OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 20, 2009**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager Air Quality Division
THROUGH:	Kendal Stegmann, Senior Environmental Manager Compliance and Enforcement
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	Eric L. Milligan, P.E., Engineering Section
SUBJECT:	Evaluation of Permit Application No. **2007-115-C (M-1) PSD** Associated Electric Cooperative, Inc. Chouteau Power Plant Mid America Industrial Park, Mayes County SW/4, SW/4 of Section 10, T20N, R19E Latitude: 36.2225N; Longitude: 95.2778W Directions: From the Mid America Industrial Park east off of State Highway 412B and North on Robertson Street

SECTION I. INTRODUCTION

Associated Electric Cooperative, Inc. (AECI) has submitted an application for construction of a natural gas-fired combined cycle (two-on-one) electricity generating facility located next to the existing Chouteau Power Plant in Mayes County, Oklahoma. The major components of the new facility will include the following:

1) Two Combustion Turbines, each mated to a nominal 178 MW generator
2) Two Heat Recovery Steam Generating Units (HRSGs) with Duct Burners that supply steam to a single 182 MW generator
3) Two Selective Catalytic Reduction units to control NO_X emissions from each combustion turbine and the duct burners
4) One Cooling Tower with nine (9) individual cells equipped with drift eliminators
5) One Auxiliary Boiler to maintain the system in hot/ready standby
6) One Fuel Gas Water Bath Heater to heat incoming gas to the combustion turbines
7) Two pressurized 10,000 gallon anhydrous ammonia tanks
8) One Emergency Diesel Generator limited to 500 hours
9) One Emergency Fire Water Pump limited to 500 hours

The new facility's emissions are in excess of the Prevention of Significant Deterioration (PSD) threshold levels. The existing facility is currently operating as authorized by Permit No. 2007-115-TVR, issued on April 23, 2008.

SECTION II. FACILITY DESCRIPTION

A. Proposed Equipment

The main emission sources from the new equipment are the two combustion turbines. The combustion turbine equipment will be supplied by Siemens-Westinghouse, and is nearly identical to the existing units. As with the existing combustion turbine units, these will also be operated with a single steam turbine in combined-cycle mode. These combustion turbines will be limited to using natural gas as a fuel, which will be obtained from a local pipeline.

The V84.3A model combustion turbines incorporate lean pre-mix dry low NO_X combustors as well as the add-on Selective Catalytic Reduction (SCR) to minimize NO_X formation. In addition, these units will utilize a new Siemens technology that will allow the combustion turbines to operate in the pre-mix mode throughout the load range. In the pre-mix mode, fuel combustion is more efficient and results in lower NO_X emissions. In contrast, the existing units must reach approximately 60% of the rated turbine load before pre-mix operation is permissible.

Each turbine's exhaust gas will duct through a natural gas fired heat recovery steam generator (HRSG) where steam will be produced and used by a steam turbine to generate additional electricity. Each HRSG is specifically designed to match the operating characteristics of the combustion turbines to provide optimum performance for the total power cycle. Each HRSG is a three-pressure, superheat and reheat, duct fired, natural circulation unit with a horizontal gas turbine exhaust flow receiver containing vertical heat tube transfer sections. Both HRSGs may utilize duct firing at 100 percent load. Duct firing generates additional heat (99 MMBTUH each) to the exhaust gases of the combustion turbines by burning natural gas. This heat energy is then converted to steam and electricity.

The primary consumer of the steam is a reheat, condensing steam turbine. It consists of a high pressure section, which receives high-pressure superheated steam from the HRSGs and exhausts to the reheat section of the HRSG. The steam from the reheat section is then supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure section of the steam turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the condenser unit. Emissions from the combustion gas turbine generator and the duct fired HRSG system will be exhausted through two stacks 130 feet above the ground surface. The combustion gas turbine generators will be shut down as necessary for scheduled maintenance, or as dictated by economic or electrical demand.

Similar to the existing facility, the system will include a 9-cell mechanical draft cooling tower with up to seven cycles of concentration. Drift (water loss) from the tower is estimated at 0.0005% of total water flow. Water treatment chemicals will be non-chromium chemicals including sodium hypochlorite and sulfuric acid. The facility may also use scale inhibitor/corrosion inhibitor, non-oxidizing biocides, and liquid dispersants similar to those currently employed on the existing system.

The new equipment will also include an auxiliary boiler (natural gas), a fuel gas heater (natural gas), and emergency fire water pump (diesel), an emergency generator (diesel), and two pressurized 10,000-gallon (anhydrous) ammonia tanks. Since this equipment is yet to be purchased, AECI will permit these new emission sources as identical to the existing auxiliary boiler, fire water pump, gas heaters, and emergency diesel generator. The equipment that is eventually purchased for the installation will meet or exceed the emission rates and have heat input capability at or below the assumed capacities. The fire water pump and emergency generator will be limited to 500 hours and are not considered in the air quality impact analysis included in this permit application.

B. Existing Facility – Title V Permit 2007-115-TVR

The existing facility will contain a "two-on-one" combined cycle gas turbine (CCGT) plant firing exclusively natural gas. Hot exhaust gases from the gas turbines are passed through two separate drum-type heat recovery steam generators (HRSG) where the heat is converted to steam which drives a single conventional steam turbine that adds about 182 MW to the plant's capacity. Waste heat is rejected through a condenser and mechanical draft-cooling tower.

Each of the two gas turbines are Siemens KWU, Model V84.3A, advanced gas turbine design with a rated output of 176 MW (1,783 MMBTUH) at IS0 conditions. This model utilizes Siemens hybrid burner ring combustor designed for pre-mix firing above 60 percent output. This machine has a 15-stage compressor and 4-stage turbine. Advanced design features, in addition to the low-NO_X hybrid burner ring combustor, include single crystal blade castings and extensive use of film cooling. Film cooling ensures high cooling efficiency in the first two turbine stages. The design allows slightly higher firing temperatures, higher exhaust temperatures, and improved heat rates, in both simple and combined cycle modes.

The HRSGs are three-pressure level boilers (low, intermediate, and high) with superheat and reheat sections. The gas turbines exhaust gases at about 1,050 °F that contact the boiler surfaces and transfer heat to the feed water and steam. This arrangement enables higher efficiencies of the combined cycle power plant by using the exhaust gas energy. Each HRSG produces about 375,000 pounds of steam per hour at 1,566 psia and 1,016 °F. The HRSGs house a selective catalytic reduction (SCR) system for each unit to reduce NO_X emissions.

The steam turbine is a Siemens K36-16/N36-2 x 6.9 two-cylinder tandem compound flow machine. The three electrical generators used to produce the nominal 530 MW are Siemens, Model TLRI-108146-36, designed for dual drive from both the steam and gas turbines.

The cooling tower is a nine cell mechanical draft tower with up to seven cycles of concentration. Drift (water loss) from the tower is about 15,000-18,000 gallons (i.e., 0.0005% of total water flow) per day at full load. Water treatment chemicals are non-chromium chemicals including sodium hypochlorite (14 lbs/day) and sulfuric acid (5,000 gallons/year). The facility may also use NALCO 1333T, a scale inhibitor/corrosion inhibitor (300-310 lbs/day) and/or NALCO 7330 a non-oxidizing biocide (1,200 lbs/year). In addition, a liquid dispersant, NALCO 8301 D is used at an approximate rate of 6.8 lbs/day.

The facility also includes an auxiliary boiler and a fuel gas heater that fire natural gas only and two pressurized 10,000-gallon anhydrous ammonia tanks. The auxiliary boiler is a Donlee boiler with a maximum design capacity of 33.5 MMBTUH. The design features include a low NO_X burner control. The boiler is utilized to maintain the turbine system in hot-ready standby. This helps minimize the duration of the startup period for each turbine, which lowers the overall emissions and the amount of time spent in the diffusion mode (high emission levels) of operation. The boiler was originally not expected to operate more than 3,000 hours in a given year. However, the boiler is permitted for continuous operation and will normally be used only when the turbines are not in operation or during startup. The fuel gas heater, rated at 18.8 MMBTUH, is used predominantly during winter months to heat a glycol/water solution that will circulate in a small heat exchanger preheating the supply of gas to prevent icing.

The plant is designed for base load operation, but has the ability to cycle. Other than specified maintenance periods, the plant is designed to have an availability of over 90 percent. However, emissions estimates for this permit were based on continuous operation and 100% load.

Other than startup, shutdown, and malfunctions, both combustion turbines are operated at approximately 60 percent rated turbine load and above to assure operations in the "pre-mix" mode. Pre-mix is the operating mode for the burner that optimizes combustion efficiency and produces the lowest NO_X emissions. However, elevated levels of NO_X and CO can result during cold startups and/or in the diffusion mode for periods up to four hours. Although the permit does limit the diffusion mode of operation to four hours, the auxiliary boiler may shorten this time to three hours, under normal operating conditions. (i.e outside startup, shutdown, and malfunctions).

SECTION III. EQUIPMENT

A. Proposed Equipment

EUG 1. Electric Generating Units

EU	Name & Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
1-03	Siemens V84.3A w/Duct Burner	1,882	800451	2009
1-04	Siemens V84.3A w/Duct Burner	1,882	800461	2009

TBD – To Be Determined

EUG 2. Auxiliary Boiler

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-02	TBD	33.5	TBD	2009

TBD – To Be Determined

EUG 3. Fuel Gas Water Bath Heater

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-02	TBD	18.8	TBD	2009

TBD – To Be Determined

EUG 4B. Emergency Diesel Generator

EU	Make/Model	hp	Serial #	Installed Date
4-02	TBD	2,200	TBD	2009

TBD – To Be Determined

EUG 5B. Emergency Fire Pump (Diesel)

EU	Make/Model	hp	Serial #	Installed Date
5-02	TBD	267	TBD	2009

TBD – To Be Determined

EUG 6. Cooling Towers

EU	Make/Model	No. of Towers	Installed Date
6-01	TBD	9	2009

TBD – To Be Determined

B. Existing Equipment

EUG 1. Electric Generating Units

EU	Name & Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
1-01	Siemens V84.3A	1,783	800390	1999
1-02	Siemens V84.3A	1,783	800394	1999

EUG 2. Auxiliary Boiler

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-01	Donlee	33.5	9920891	1999

EUG 3. Fuel Gas Water Bath Heater

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-01	ThermoFlux/CryoFlux	18.8	9105	1999

EUG 4A. Emergency Diesel Generator

EU	Make/Model	hp	Serial #	Installed Date
4-01	Detroit Diesel/T1237K36	2,200	5262000436	2000

EUG 5A. Emergency Fire Pump (Diesel)

EU	Make/Model	hp	Serial #	Installed Date
5-01	Caterpillar/3306- A552598	267	64Z29015	1999

EUG 6. Cooling Towers

EU	Make/Model	No. of Towers	Installed Date
6-01	Psychometrics, Inc	9	1999

SECTION III. SCOPE OF REVIEW AND EMISSIONS

Since the project will increase emissions by more than the PSD significance thresholds for NO_X, CO, and PM_{10} the project is subject to full PSD review. The project is also subject to NSPS, Subpart GG for combustion turbines. Numerous Oklahoma Air Quality rules affect the new turbines, duct burners, backup diesel generator, diesel fire water pump engine, and auxiliary boiler as fuel-burning equipment, rules including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities are evaluated for all pollutant-specific rules, regulations and guidelines.

This project involves a number of emission points. Emissions are generated by combustion at the turbines, at the duct burners, at the auxiliary boiler and fuel gas water bath heater, and to a much smaller extent at the backup diesel generator and fire water pump. Each HRSG stack exhausts combustion emissions from the duct burner and related turbine. Very small emissions of VOC are expected from the diesel storage tanks. Ammonia is supplied to the SCR process in amounts slightly above the stoichiometric requirement, so there will be some emissions of ammonia, called “ammonia slip,” in the exhaust.

A. Criteria Pollutants - Proposed Equipment

Turbine emissions are based on continuous operation of the turbines, use of SCR, and the manufacturer's data as listed below:

Pollutant	Units	Concentration
NO_X	ppmvd @ 15% O_2	2.0
CO	ppmvd @ 15% O_2	8.0
VOC	ppmvd @ 15% O_2	0.3
Ammonia	ppmvd @ 15% O_2	10.0

Although the plant is expected to operate at a 70 to 75% capacity factor, short and long term emissions for the turbines were based on 100% load since this resulted in the highest emissions. VOC emissions, from the turbines with duct burners firing, are estimated at 0.0028 lb/MMBTU for the turbines with duct burners. SO_2 emissions, from the turbines with duct burners firing, are estimated at 0.00056 lb/MMBTU based on usage of natural gas with a sulfur content of 0.25 grains/100 SCF. PM_{10} emissions, from the turbines with duct burners firing, are estimated at 0.0035 lb/MMBTUH based on stack testing of a similar unit.

Since market forces and other factors may force the facility to experience many startups and shutdowns during the course of a year an analysis of annual emissions for NO_X and CO based on the historical number of startups and shutdowns was used to determine annual emissions. Startup and shutdown are not expected to affect emissions of VOC, SO_2, and PM_{10}.

Estimated NO_X Emissions (Per Unit) Combustion Turbine with Duct Burner

Operating Mode	Event Duration (hr)	Number of Events	Total Hours	lb/event	lb/hr	TPY
Cold Startup	4	20	120	568	142.00	5.68
Warm Startup	3	120	360	426	142.00	25.56
Hot Startup	2.5	100	250	355	142.00	17.75
Shutdown	1	240	240	142	142.00	17.04
Normal	----	----	7,790	N/A	15.25	59.42
Total						**125.45**

Estimated CO Emissions (Per Unit) Combustion Turbine with Duct Burner

Operating Mode	Event Duration (hr)	Number of Events	Total Hours	lb/event	lb/hr	TPY
Cold Startup	4	20	120	1,596.00	399.00	15.96
Warm Startup	3	120	360	1,197.00	399.00	71.82
Hot Startup	2.5	100	250	997.50	399.00	49.88
Shutdown	1	240	240	399.00	399.00	47.88
Normal	----	----	7,790	N/A	51.32	199.89
Total						**385.43**

Emissions from the auxiliary boiler and fuel gas water bath heater are based on manufacturer's data and 8,760 hours/year of operation. Emissions from the backup diesel generator are based on NSPS, Subpart IIII emission limits and 500 hours/year of planned operation. Emissions from the diesel fire water pump are based on NSPS, Subpart IIII emission limits and 500 hours/year of planned operation except for SO_2 emissions which are based on AP-42 (10/96), Section 3.4. SO_2 emissions from the backup diesel generator and diesel fire water pump are based on a fuel sulfur content of 0.05 % sulfur by weight. Emissions from the cooling tower were based on a conservative estimate of 10,920-ppmw of Total Dissolved Solids (TDS) in the cooling tower drift and a total circulating water flow of 130,000 gallons per minute. The expected drift is approximately 0.0005% of the circulating water flow.

Emissions from the Electrical Generating Units

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr[1]	TPY[2]	lb/hr[1]	TPY[2]	lb/hr[1]	TPY	lb/hr[1]	TPY	lb/hr[1]	TPY
1-03	15.25	125.45	51.32	385.43	5.27	23.08	1.06	4.62	6.59	28.86
1-04	15.25	125.45	51.32	385.43	5.27	23.08	1.06	4.62	6.59	28.86
Subtotal	**30.50**	**250.90**	**102.64**	**770.86**	**10.54**	**46.16**	**2.12**	**9.24**	**13.18**	**57.72**

1 - lb/hr emissions are based on the worst case scenarios for the turbines with the duct burners firing.

2 - TPY values include startup emissions based on a representative sample of data from the existing units and 8,760 hours of operation.

Emissions from the Auxiliary Boiler

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2-02	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49

Emissions from the Fuel Gas Water Bath Heater

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3-02	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44

Emissions from the Emergency Diesel Generator[1]

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4-02	23.15	5.79	12.66	3.16	1.55	0.39	0.89	0.22	0.72	0.18

1 – Based on standards from § 89.112; NO_X is inclusive of NMHC. VOC emissions are estimated based on the AP-42 (10/96), Section 3.4 TOC factor.

Emissions from the Emergency Fire Pump (Diesel)

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
5-02	4.59	1.15	1.53	0.38	0.66	0.16	0.11	0.03	0.24	0.06

1 – Based on standards from NSPS, Subpart IIII, Table 4 (2008 & earlier factors); NO_X is inclusive of NMHC. VOC emissions are estimated based on the AP-42 (10/96), Section 3.3 TOC factor.

Emissions from the Cooling Tower

EU	NOx		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
6-02	--	--	--	--	--	--	--	--	3.55	15.56

B. Criteria Pollutants - Existing Facility

Turbine emissions are based on continuous operation of the turbines, use of SCR, and the manufacturer’s data as listed below:

Pollutant	Units	Concentration
NO_X	ppmvd @ 15% O_2	12.0
CO	ppmvd @ 15% O_2	10.0
VOC	ppmvd @ 15% O_2	0.3
Ammonia	ppmvd @ 15% O_2	10.0

Although the plant is expected to operate at a 70 to 75% capacity factor, short and long term emissions for the turbines were based on 100% load since this resulted in the highest emissions. VOC emissions, from the turbines with duct burners firing, are estimated at 0.0028 lb/MMBTU for the turbines with duct burners. SO_2 emissions, from the turbines with duct burners firing, are estimated at 0.00056 lb/MMBTU based on usage of natural gas with a sulfur content of 0.25 grains/100 SCF. PM_{10} emissions, from the turbines with duct burners firing, are estimated at 0.0035 lb/MMBTUH based on stack testing of a similar unit. Emissions from the auxiliary boiler and fuel gas water bath heater are based on manufacturer’s data and 8,760 hours/year of operation. Emissions from the backup diesel generator are based on AP-42 (10/96), Section 3.4 and 500 hours/year of planned operation. Emissions from the diesel fire water pump are based on AP-42 (10/96), Section 3.3 and 500 hours/year of planned operation except for SO_2 emissions which are based on AP-42 (10/96), Section 3.4. SO_2 emissions from the backup diesel generator and diesel fire water pump are based on a fuel sulfur content of 0.05 % sulfur by weight. Emissions from the cooling tower were based on a conservative estimate of 10,920-ppmw of Total Dissolved Solids (TDS) in the cooling tower drift and a total circulating water flow of 130,000 gallons per minute. The expected drift is approximately 0.0005% of the circulating water flow.

Emissions from the Electrical Generating Units

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**
1-01	86.70	379.75	59.00	258.42	4.99	21.87	1.00	4.38	6.24	27.33
1-02	86.70	379.75	59.00	258.42	4.99	21.87	1.00	4.38	6.24	27.33
Subtotal	**173.40**	**759.50**	**118.00**	**516.84**	**9.98**	**43.74**	**2.00**	**8.76**	**12.48**	**54.66**

[1] - lb/hr emissions are based on the worst case scenarios for the turbines.

Emissions from the Auxiliary Boiler

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-01	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49

Emissions from the Fuel Gas Water Bath Heater

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
3-01	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44

Emissions from the Emergency Diesel Generator

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
4-01	52.80	13.20	12.10	3.03	1.41	0.35	0.89	0.22	1.54	0.39

Emissions from the Emergency Fire Pump (Diesel)

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
5-01	8.28	2.07	1.78	0.45	0.66	0.17	0.11	0.03	0.59	0.15

Emissions from the Cooling Tower

	NO_x		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
6-01	--	--	--	--	--	--	--	--	3.55	15.56

Facility Wide Criteria Pollutant Emissions from the Facility

	NOx		CO		VOC		SO_2		PM_{10}	
EUs	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Proposed										
1-03 & 04	30.50	250.90	102.64	770.86	10.54	46.16	2.12	9.24	13.18	57.72
2-02	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49
3-02	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44
4-02	23.15	5.79	12.66	3.16	1.55	0.39	0.89	0.22	0.72	0.18
5-02	4.59	1.15	1.53	0.38	0.66	0.16	0.11	0.03	0.24	0.06
6-02	--	--	--	--	--	--	--	--	3.55	15.56
Subtotals	**63.30**	**280.01**	**122.24**	**798.10**	**13.39**	**49.52**	**3.16**	**9.67**	**18.13**	**75.45**
Existing										
1-01 & 02	173.40	759.50	118.00	516.84	9.98	43.74	2.00	8.76	12.48	54.66
2-01	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49
3-01	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44
4-01	52.80	13.20	12.10	3.03	1.41	0.35	0.89	0.22	1.54	0.39
5-01	8.28	2.07	1.78	0.45	0.66	0.17	0.11	0.03	0.59	0.15
6-01	--	--	--	--	--	--	--	--	3.55	15.56
Subtotals	**239.54**	**796.94**	**137.29**	**544.02**	**12.69**	**47.07**	**3.04**	**9.19**	**18.60**	**72.69**
Total	**302.84**	**1,077.0**	**259.53**	**1,342.1**	**26.08**	**96.59**	**6.20**	**18.86**	**36.73**	**148.14**

C. Hazardous Air Pollutants (HAPs) - Proposed Equipment

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the auxiliary boiler and heater are based on AP-42, Section 1.4 (7/98). HAP emissions from the emergency generator and fire water pump are based on AP-42, Sections 3.4 and 3.3 (10/96), respectively. Only emissions greater than 1.0E-3 (lb/hr and TPY) are listed.

HAP Emissions
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
HAP	**CAS #**	**lb/hr**	**TPY**
1,3-Butadiene	106990	0.002	0.008
Acetaldehyde	75070	0.151	0.660
Acrolein	107028	0.024	0.105
Arsenic	7440382	0.000	0.001
Barium	7440393	0.055	0.191
Benzene	71432	0.139	0.610

HAP Emissions (Continued)
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
Ethylbenzene	100414	0.121	0.528
Formaldehyde	50000	2.638	11.556
Hexane	110543	0.081	0.354
Naphthalene	91203	0.005	0.022
POM	N/A	0.011	0.035
Propylene Oxide	75569	0.109	0.478
Toluene	108883	0.490	2.144
Xylene	1330207	0.241	1.055

D. Hazardous Air Pollutants (HAPs) – Existing Facility

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the auxiliary boiler and heater are based on AP-42, Section 1.4 (7/98). HAP emissions from the emergency generator and fire water pump are based on AP-42, Sections 3.4 and 3.3 (10/96), respectively. Only emissions greater than 1.0E-3 (lb/hr and TPY) are listed.

HAP Emissions
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
HAP	**CAS #**	**lb/hr**	**TPY**
1,3-Butadiene	106990	0.002	0.007
Acetaldehyde	75070	0.144	0.625
Acrolein	107028	0.025	0.100
Arsenic	7440382	0.000	0.001
Barium	7440393	0.055	0.191
Benzene	71432	0.139	0.610
Ethylbenzene	100414	0.114	0.500
Formaldehyde	50000	2.539	11.105
Hexane	110543	0.081	0.354
Naphthalene	91203	0.007	0.021
POM	N/A	0.011	0.035
Propylene Oxide	75569	0.007	0.021
Toluene	108883	0.468	2.032
Xylene	1330207	0.231	1.000

SECTION IV. PSD REVIEW

As shown in the emission summary below, the previously permitted and proposed facility will have potential emissions above the PSD significance levels for NO_X, CO, VOC, and PM_{10} and are reviewed below.

EMISSIONS INCREASES COMPARED TO PSD LEVELS OF SIGNIFICANCE

Pollutant	Emissions (TPY)	PSD Levels of Significance (TPY)	PSD Review Required?
NO_X	280	40	Yes
CO	798	100	Yes
VOC	50	40	Yes
SO_2	10	40	No
PM/PM_{10}	64	25/15	Yes
H_2SO_4	1	7	No

Full PSD review of emissions consists of the following:

A. Determination of best available control technology (BACT)
B. Air Quality Impacts
C. Evaluation of source-related impacts on growth, soils, vegetation, visibility
D. Evaluation of Class I area impacts

A. Best Available Control Technology (BACT)

Methodology

A BACT analysis is required for each new or physically modified emissions unit for each pollutant which exceeds an applicable PSD Significant Emission Rate (SER). The pollutants subject to review under the PSD regulations include nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulates less than or equal to 10 microns in diameter (PM_{10}). The BACT review follows the "top-down" approach recommended by the EPA.

BACT must be at least as stringent as any NSPS applicable to the emissions source. After determining whether any NSPS is applicable, the first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically infeasible for the unit in question, the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical or environmental concerns. The remaining technologies are evaluated on the basis of operational and economic effectiveness. The EPA-required top-down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc.

Presented below are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, Draft BACT Guidelines:

Step 1. Identification of all control technologies
Step 2. Determination of technical feasibility of control options
Step 3. Ranking of remaining control technologies by control effectiveness
Step 4. Evaluation of most effective controls and document results
Step 5. Selection of BACT

Control technologies and related emissions data were identified through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

The BACT analysis for this project includes two gas combustion turbines an auxiliary boiler, a fuel gas heater, a cooling tower, and auxiliary equipment as listed below.

Emission Sources included in the BACT Analysis

EU ID	**Source Description**
EU 1-03	Siemens V84.3A Turbine
EU 1-04	Siemens V84.3A Turbine
EU 2-02	Auxiliary Boiler
EU 6-02	Cooling Tower
EU 3-02, 4-02, 5-02	Auxiliary Equipment

BACT Evaluation for Gas Turbines (Normal Operations)

<u>Step 1 – Identification of all control technologies</u>

The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility. Research of emerging air-pollution control technologies for turbines and cooling towers was also performed. Summary of the control technologies identified for each of the applicable pollutants are presented on the following page.

Possible Control Technologies

Emission Unit	Pollutant	Control Technology
Combined Cycle Gas Turbines (>50MW)	NO_X	$SCONO_X$
		Catalytic Combustion (XONON[tm])
		Selective Catalytic Reduction (SCR)
		Lean-Premix (Dry Low-NO_X Combustors)
		Steam / Water Injection
		Selective Non-Catalytic Reduction (SNCR)
		Good Combustion Practices
	CO	Catalytic Oxidation
		Good Combustion Practices
	VOC	Catalytic Oxidation
		Good Combustion Practices
	PM/PM_{10}	Good Combustion Practices
		Fuel Specification: Clean-Burning Fuels
Auxiliary Boiler	NO_X	Dry Low-NO_X Combustors
	Other criteria pollutants	Natural Gas with Good Combustion Practices
Cooling Tower	PM/PM_{10}	Drift Eliminators
Auxiliary Equipment	NO_X, CO, VOC, PM/PM_{10}	Good Combustion Practices, Fuel Specification: Clean-Burning Fuels

<u>Step 2 – Determination of Technical Feasibility of Identified Control Options</u>

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those which are clearly technically infeasible are identified and not considered further.

NO_X Control Technologies

NO_X are formed during the fuel combustion process. There are three types of NO_X formations: thermal NO_X, fuel-bound NO_X, and prompt NO_X. Thermal NO_X is created by the high temperature reaction in the combustion chamber between atmospheric nitrogen and oxygen. The amount that is formed is a function of time, turbulence, temperature, and fuel to air ratios within the combustion flame zone. Fuel-bound NO_X is created by the gas-phase oxidation of the elemental nitrogen contained within the fuel. Its formation is a function of the fuel nitrogen content and the amount of oxygen in the combustion chamber. Fuel NO_X is temperature-dependent to a lesser degree; at lower temperatures, the fuel-bound nitrogen will form N_2 rather than NO_X. The fuel specification for these turbines, natural gas, has inherently low elemental nitrogen, so the effects of fuel NO_X are insignificant in comparison to thermal NO_X. Prompt NO_X occurs primarily in combustion sources that use fuel rich combustion techniques. The formation of prompt NO_X occurs through several early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The reactions primarily take place within fuel rich flame zones and are usually negligible when compared to the formation of NO_X by the thermal NO_X process. Combustion turbines generally have high mixing efficiencies with excess air, rich combustion zones rarely exist, and the formation of prompt NO_X is not deemed a significant contributing factor towards NO_X formation.

Since the formation of NO_X is largely dependent on thermal NO_X, several control technologies are used to reduce the precursors of NO_X formation or use catalysts to treat the post-combustion emissions. There are three types of emission controls for natural gas-fired turbines. The least effective are wet controls, which use steam or water injected into the combustion zone to reduce the ambient flame temperature, thus limiting NO_X formation. Intermediate are dry controls that use advanced combustor design to suppress NO_X formation. Most effective are post-combustion catalytic controls that selectively or non-selectively reduce NO_X.

$SCONO_X$™

$SCONO_X$™, is an emerging catalytic and absorption technology that has shown some promise for turbine applications. SCONOx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce CO and NO_X emissions from natural gas fired turbines. The catalyst oxidizes carbon-monoxide (CO) to carbon-dioxide (CO_2), and nitric oxide (NO) to nitrogen-dioxide (NO_2). The CO_2 is exhausted while the NO_2 absorbs onto the catalyst to form potassium nitrites (KNO_2) and potassium nitrates (KNO_3). This technology does not involve injection of ammonium, as most SCR technologies, and therefore it is not associated with ammonium slip emissions.

In 1998, the CA EPA Environmental Technology Certification Program reviewed the $SCONO_X$ technology and validated the claims of the manufacturer Emera Chem. However, the largest turbine at which the $SCONO_X$™ system has been installed is a 43 MW turbine in the City of Redding, CA. In recent years Emera Chem has come up with a new generation of the $SCONO_X$**™** technology, marketed under the name EM_X. According to the manufacturer, currently the largest application of the EM_X technology is at a 6 MW turbine.

Since the $SCONO_X$™ and EM_X technologies have not been applied at a turbine with size comparable to the size of the proposed installations, they are not considered further.

Catalytic (Flameless) Combustion (XONON™)

While several companies have been reported to be working on this technology, it was first introduced commercially by Catalytica, Inc., and is being marketed under the name XONON™. The XONON™ technology replaces traditional flame combustion with flameless catalytic combustion. NO_X control is accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_X is formed. The XONON™ combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

The XONON™ technology has been successfully implemented in a field trial at Silicon Valley Power, a municipal power company in Santa Clara, California. The NO_X emissions were well below 2.5 ppmvd on 1.5 MW Kawasaki M1A-13A gas turbines. Catalytica Combustion Systems (manufacturer of XONON™) had a collaborative commercialization agreement with General Electric Power Systems for the development of XONON™ systems for large scale gas turbines. However, in the last few years only one facility nationwide, a 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California, has attempted to employ the XONON™ system. According to a decision by the California Energy Commission (December 2000), XONON™ system was selected as the primary NO_X BACT pollution control technology for the Pastoria Energy Facility but the facility was given the option to use SCR if XONON™ system proved to be not feasible for scale up. The facility has employed SCR upon construction. The lack of large-scale operating experience and the lack of commercial availability preclude the use of XONON™ for gas turbine NO_X reduction for this project. Thus, the XONON™ catalytic combustion system is not considered further.

Selective Catalytic Reduction (SCR)
SCR systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface to form molecular nitrogen (N_2) and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules into the HRSG portion of the combined-cycle gas turbine downstream of the superheater. Ammonia is injected into the exhaust gases prior to passage through the catalyst bed. Even under normal operation of a SCR system, a portion of the injected ammonia passes unreacted through the catalyst and gets emitted out of the stack. These ammonia emissions are called ammonia slip.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 450 to 800 °F. If the temperature drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature becomes too high, the catalyst may begin to decompose and NH_3 is oxidized to NO_X. Turbine exhaust gas is generally in excess of 1,000 °F but the HRSG cools the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of 50 - 95 % control efficiency.

SCR is the most widely applied post-combustion control technology in turbine applications, and is currently accepted as LAER for new facilities located in ozone non-attainment regions. When combining with Dry-Low NO_X combustor, it can reduce NO_X emissions to as low as 2 ppmvd at 15% O_2 for standard combustion turbines with and without duct burner firing.

As mentioned previously, a possible side effect of this NO_X control system is ammonia slip. Ammonia slip occurs because the exhaust temperature falls outside the optimum catalyst reaction range or because the catalyst itself becomes prematurely fouled or exceeds its life expectancy. When the units meet the minimum temperature at the HRSG to activate the catalyst and employ the SCR, the units require only enough ammonia to control NO_X emissions to permitted levels. Negligible levels of ammonia slip should occur on these units since it is not in the interest of the facility to allow excess emissions of ammonia. Gas turbines using SCR typically have been limited to 5-10 ppmvd ammonia slip at 15 % $O_{2.}$

Lean-Premix Technology (Dry-Low NO_X)
Turbine manufacturers have developed processes that use air as a diluent to reduce combustion flame temperatures, and have achieved reduced NO_X by premixing the fuel and air before they enter the combustor. This type of process is called lean-premix combustion, and goes by a variety of names, including the Dry-Low NO_X (DLN) process of General Electric, the Dry-Low Emissions (DLE) process of Rolls-Royce and the $SoLoNO_X$ process of Solar Turbines.

The burner, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long can, an axially-centered ring of long cans (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_X. In contrast, lean-premix combustors minimize combustion temperatures by providing a lean-premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_X formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame.

To achieve low NO_X emission levels, the air/fuel ratio must be maintained near the lean flammability limit of the mixture. In the standard burner technology, such as is employed in EU 1-01 and 1-02, lean-premix combustors are designed to maintain this air/fuel ratio at around 60% of the rated load and above. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emission that occur as the air/fuel ratio reaches the lean flammability limit, standard lean-premix combustors switch to diffusion combustion mode at reduced load conditions. This operation in diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled. Lean-premix technology is the most widely applied pre-combustion control technology in natural gas turbine applications. It has been demonstrated to achieve emissions as low as 9 ppmvd NO_X at 15% O_2, with removal efficiency in the range of 40-95%.

The proposed combustion turbine units will be equipped with new burner technology that allows for operation in the pre-mix mode throughout the load range. This means that the higher emitting diffusion mode is no longer required at lower loads, and the resulting pollutant concentrations are lower during startup and shutdown compared to the standard design. In August of 2005, the Air Quality Division of ODEQ approved an equipment modification of EU 1-01 to operate in the same manner as described here. Ultimately, the combustion system of EU 1-01 was never modified to the new design. Based on the experience with the new units, AECI may revisit these modifications to EU 1-01 and 1-02 in the future.

Steam/Water Injection

Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. Conversely, more NO_X is produced as the gas turbine inlet temperature is increased. Diluent injection, or wet controls, can be used to reduce NO_X emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_X emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_X forming regions of the combustor.

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Non-uniform mixing of water and fuel creates localized “hot spots” in the combustor that generate NO_X emissions. Increased NO_X emissions require more diluent injection to meet a specified level of emission. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Newer gas turbines usually apply steam injection since it does not increase the heat rate as much as water. Further, carbon monoxide emissions are lower, pressure oscillations are less severe, and maintenance is reduced relative to water injection.

Water injection typically results in a NO_X reduction efficiency in the range 30 - 70 %, with emissions below 42 ppmvd NO_X at 15 % O_2. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions of 25 ppmvd NO_X at 15 % O_2 (30 - 82 % control efficiency range). Water/steam injection is not further reviewed in this BACT analysis because it results in NO_X emissions that are in excess of those achieved by advanced DLN combustors. In addition, the water consumption and sludge treatment/disposal requirements associated with water/steam injection do not exist for DLN combustors.

Selective Non-Catalytic Reduction (Thermal DeNO$_X$^{TM})

Selective non-catalytic reduction (SNCR), also known as Thermal DeNO$_X$ uses ammonia or urea agent which reduces the NO_X in the flue gas to N_2 and H_2O. In practice, this technology has been applied in boilers by injecting ammonia into the high temperature region of the exhaust stream (e.g., 1,300 ºF to 2,000 ºF). Incorrect location of injection points, insufficient residence times and injection rate calibration error may result in excess emissions of ammonia (ammonia slip). However, when successfully applied, SNCR has shown reduction efficiency in NO_X emissions from boilers of 35 to 60 %.

The only known commercial applications of Thermal DeNO$_X$^{TM} are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800 ºF. There are no known applications on or experience with combustion turbines. Temperatures of 1,800 ºF require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased. Since this control option has not been demonstrated on combustion turbines, it is not considered technically feasible and is precluded from further consideration in this BACT analysis.

CO Control Technologies

Carbon monoxide is formed as a result of incomplete combustion of fuel. CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors however tend to result in high NO_X emissions. Therefore, a low NO_X emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve lowest NO_X emissions rate possible while also optimizing CO emission rates.

A review of EPA's RACT/BACT/LAER Clearinghouse indicated that CO emission control methods include exhaust gas cleanup methods such as catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

Good Combustion Practices

According to the EPA's RBLC database, more than 2/3 of the recent BACT determinations for CO were use of good combustion practices. Efficient burners can minimize the formation of CO by providing excess oxygen, mixing the fuel thoroughly with air and by employing general good combustion practices. The CO emission limits set for installations with good combustion practices BACT are in the range of 2 to 40 ppmvd at 15% O_2.

Catalytic Oxidation

Another CO control technology for natural gas fired combined-cycle turbines is an oxidation catalyst system. Just like with SCR catalyst technology for NO_X control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The oxidation is carried out by the following overall reaction:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2$$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Under ideal operating conditions, this technology can achieve an 80% reduction in CO emissions.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the HRSG for proper turbine exhaust lateral distribution. It is important that the gas flow is evenly distributed across the catalyst and that proper operating temperature at base load design conditions is maintained. Operation with duct burners, at part load, or during start-up/shutdown will result in less than optimum temperatures and reduced control efficiency.

Catalyst systems are subject to loss of activity over time. Catalyst fouling occurs slowly under normal operating conditions and may be accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical

3-year guarantee to a 5 to 7 year predicted life. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system also would be expected to control a small percent (5-40%) of hydrocarbon (VOC) emissions.

A CO catalyst also will oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but is further oxidized to SO_3 across a catalyst (30% conversion is assumed). SO_3 will then be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) from the exhaust stack. These sulfates condense in the gas stream or within the atmosphere as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and to some extent VOC, but would increase emissions of PM_{10} and $PM_{2.5}$. Also, the increased backpressure of the catalyst bed would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants.

According to the EPA's RBLC database, a number of combined cycle gas fired turbines have been issued permits where oxidation catalysis systems are selected as the BACT. The CO emission limits for these BACT determinations are in the range of 1.3 to 25 ppmvd at 15% O_2.

VOC Control Technologies

A review of the EPA's RBLC indicates that VOC emissions from large gas-fired turbines are controlled either via the use of good combustion practices or the use of oxidation catalyst.

Catalytic Oxidation

As mentioned earlier, an oxidation catalyst designed to control CO would provide a side benefit of controlling 5 to 40 % of the VOC emissions. However, the same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions apply to the use of this technology for collateral control of VOC. Some of them are narrow operating temperature range, loss of catalyst activity over time, and system pressure losses leading to increased fuel consumption. According to the EPA's RBLC database, the emission limits for facilities with good combustion practices BACT were set in the range 0.4-23 ppmvd at 15% O_2.

Good Combustion Practices

Another VOC control option is the employment of combustion controls where VOC emissions are minimized by optimizing fuel mixing, excess air, and combustion temperature to assure complete combustion of the fuel. According to the EPA's RBLC database the VOC emission limits for the facilities with oxidation catalyst BACT are in the range 0.4-34 ppmvd at 15% O_2.

PM Control Technologies

Some total suspended particulates (TSP) and particulate matter less than 10 micrometers will occur from the combustion of natural gas. The EPA's AP-42, Fifth Edition, Supplement D, Section 1, considers that particulate matter from natural gas combustion is less than 1 micron; therefore it is considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles. PM_{10} emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, the use of natural gas is in and of itself a highly efficient method of controlling emissions.

A review of the EPA's RBLC database indicates that there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. The lowest PM_{10} BACT emission limit has been set at 4.1 lb/hr, while the range of emission limits is from 4.1 to 45 lb/hr.

Step 3 – Ranking of control technologies by control effectiveness

All identified controlled technologies and their control efficiencies are presented below. The technologies are ranked in order of decreasing effectiveness and the technologies determined as non-feasible are indicated as such.

Ranked controlled technologies by control efficiency

Pollutant	Control Technology	Control Efficiency (%)	Technical Feasibility
NO_X	Selective Catalytic Reduction (SCR)	50 - 95	Feasible
	Dry Low-NO_X (DLN) Combustors	40 - 95	Feasible
	Water/Steam Injection	30 - 82	Feasible
	Selective Non-Catalytic Reduction (SNCR)	35 - 60	Non-Feasible
	$SCONO_X$™	N/A	Unproven
	XONON™	N/A	Unproven
	Good combustion practices	Base Case	Feasible
CO	Oxidation Catalyst	60 - 80	Feasible
	Good combustion practices	Base Case	Feasible
VOC	Oxidation Catalyst	5 - 40	Feasible
	Good combustion practices	Base Case	Feasible
PM	Good combustion practices	Base Case	Feasible

Step 4 – Evaluation of the most effective controls

NO_X Control Technologies

A technology review showed that currently the most effective control technology for NO_X, which has been commercially proven, is Selective Catalytic Reduction (SCR). The use of a Dry-Low NO_X (DLN) combustion process has also been established as another very effective technology to control NO_X emissions from large gas-fired turbines.

The combined use of SCR (with a maximum ammonia slip of 10 ppmvd at 15% O_2) and DLN combustors is selected as BACT for NO_X for the proposed facility expansion, with NO_X emission limit of 2 ppmvd at 15% O_2 (1-hour average). A review of the EPA's RBLC indicates that the proposed emission limit is well within the range of the NO_X emission limits determined for other large combustion turbines in the last few years.

CO Control Technologies

There is no "Bright Line" cost effectiveness threshold for CO; rather, the cost presented for a specific project for control of CO are compared with the cost per ton that have been required of other sources in the same geographical area. For example, a project located in a rural attainment area where dispersion modeling shows less than significant air quality impacts would have a different cost criteria than a project located in or near an urban CO non-attainment area where there is a legitimate need to minimize emissions of CO. It should also be noted that cost effectiveness is a pollutant specific standard. For instance, the cost effectiveness of controlling the more pervasive pollutant NO_X (an acid rain pollutant, a precursor to the formation of regional haze, and a precursor to the formation of ozone) is aptly higher than for the more benign stack level emissions of CO. Areas of CO non-attainment are primarily urban and exceedances of the CO NAAQS are dominated by ground level releases due to automobiles. CO emitted from a power plant stack is quickly dispersed (as shown in the modeling analysis) and is an unstable molecule that naturally is converted to CO_2 in the atmosphere.

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) emissions. Further, the catalyst bed would create an increased backpressure which would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants. In addition, the cost effectiveness of a catalyst system to control emissions of CO is estimated at $9,600 per ton of removed CO, which is well above the benchmark of $2,000 per ton removed pollutant. Capital and annual costs associated with installation of an oxidation catalyst system were calculated using vendor quotes.

The fact that the use of oxidation catalyst for CO reduction would be associated with increase in other emissions, the very high cost per ton of this technology, as well as the regional air quality conditions, leads to the determination that combustion controls represent BACT for large gas-fired turbines. In addition, the resulting CO emissions do not exceed the Modeling Significance Levels (MSLs). There are no expected adverse economic, environmental or energy impacts associated with the use of the proposed control alternative. The proposed CO BACT limit is 8 ppmvd at 15% O_2.

VOC Control Technologies

Since the use of oxidation catalyst has been shown to not be cost effective for the control of CO, it could not be cost effective for control of 5-40 % of the VOC emissions. Therefore, an oxidation catalyst cannot be considered to represent BACT for VOC emissions. The proposed BACT is good combustion practices with emission limit of 0.3 ppmvd at 15% O_2.

PM Control Technologies

The established BACT for PM_{10} emissions from the large natural gas-fired combustion turbines is the use of a low ash fuel (natural gas) and efficient combustion. This BACT choice is protective of any reasonable opacity standard. Typically, plume visibility is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative. The proposed PM_{10} emission limit for this facility expansion is 6.59 lb/hr (filterable plus condensable) which is in the range of the set BACT PM_{10} limits for similar facilities.

<u>Step 5 – Selection of BACT</u>

Summary of Selected BACT for Gas Turbines

Pollutant	Control Technology	Proposed Permit Limit
NO_X	SCR with Dry Low-NO_X combustors	2 ppmvd @ 15% O_2
CO	Good combustion practices	8 ppmvd @ 15% O_2
VOC	Good combustion practices	0.3 ppmvd @ 15% O_2
PM_{10}	Good combustion practices	10.56 lb/hr (filter + cond)

BACT Evaluation for Gas Turbines (Startup/Shutdown)

A review of the EPA's RBLC database in April 2008 did not identify any control technologies for gas turbines specifically during the startup and shutdown periods. Therefore, BACT is proposed as a limit on the quantity of emissions during startup and shutdown while minimizing the startup and shutdown periods.

Event	Maximum Duration (hr)	NO_X Emissions (lbs/event)	CO Emissions (lbs/event)
Startup	4	568	1,596
Shutdown	1	142	399

BACT Evaluation for Cooling Tower

The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

The performed research showed that the only PM control technology for cooling towers is the design of cooling towers to minimize/eliminate drift. The drift eliminators are specifically designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to a review of the EPA's RBLC, can reduce drift to 0.0005 % of cooling water flow, which reduces particulate emissions. The use of drift eliminators to attain an emission rate of 0.40 lb/hr per cell is determined as BACT for cooling tower particulate emissions. This BACT does not have any adverse environmental or energy impacts.

BACT Evaluation for Auxiliary Boiler

The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

The boiler design will incorporate low-NO_X burners for NO_X control, which is common for natural gas-fired auxiliary boilers. Since the auxiliary boiler will fire natural gas, the same properties that applied to the combustion turbines will also apply to this application. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for the other criteria pollutants requiring add-on controls. Therefore, BACT is proposed to be the use of low-NO_X burners and efficient combustion. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative.

BACT Evaluation for Auxiliary Equipment

Prospective auxiliary equipment for the facility includes the following:

- Fuel Gas Water Bath Heater No. 2 (natural gas fired)
- Emergency Generator No. 2 (diesel fired)
- Emergency Fire Pump No. 2 (diesel fired)

Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

These units will incorporate modern combustion design to minimize emissions. Baseline emissions are based on the NSPS, if available. Baseline emissions for the compression ignition engines are based on NSPS, Subpart IIII emission limits. Fuel specifications will require "Clean-Burning Fuels" to further reduce emissions. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for the criteria pollutants requiring add-on controls. Therefore, BACT is proposed to be the use of good combustion design, efficient combustion and fuel specification for clean burning fuels. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative.

Summary of Selected BACT

Pollutant	Gas Turbine with Duct Burner (permit limit)	Gas Turbine Startup (permit limit)	Gas Turbine Shutdown (permit limit)
NO_X	SCR with dry low-NOx combustors (2.0 ppmvd @ 15% O_2 & 10 ppmvd ammonia slip)	568 lb/event & a maximum of 4 hours/event	142 lb/event & a maximum of 1 hour/event
CO	Good combustion control (8 ppmvd @ 15% O_2)	1,596 lb/event & a maximum of 4 hours/event	399 lb/event & a maximum of 1 hour/event
VOC	Good combustion practice (5.27 lb/hr)	N/A	N/A
SO_2	Low sulfur fuel – natural gas (1.06 lb/hr)	N/A	N/A
PM_{10}	Good combustion control & use of natural gas (6.59 lb/hr)	N/A	N/A

Summary of Selected BACT (Continued)

Pollutant	Auxiliary Boiler (permit limit)	Fuel Gas Heater (permit limit)	Diesel Engine/Fire Water Pump (permit limit)
NO_X	Low NO_X burners (2.36 lb/hr)	Good design & operating practices (2.70 lb/hr)	NSPS, Emission Limits[1] (23.15/4.59 lb/hr)
CO	Good combustion practices (5.02 lb/hr)	Good combustion practices (0.39 lb/hr)	NSPS, Emission Limits (12.66/1.53 lb/hr)
VOC	Good design & operating practices (0.54 lb/hr)	Good design & operating practices (0.10 lb/hr)	Good engine design (1.55/0.66 lb/hr)
SO_2	Low sulfur fuel – natural gas (0.03 lb/hr)	Low sulfur fuel – natural gas (0.01 lb/hr)	0.05% sulfur diesel (0.89/0.11 lb/hr)
PM_{10}	Good combustion practice (0.34 lb/hr)	Good combustion practice (0.10 lb/hr)	NSPS, Emission Limits (0.72/0.24 lb/hr)

[1] - NOX is inclusive of NMHC.

B. Air Quality Impacts

Prevention of Significant Deterioration (PSD) is a construction permitting program designed to ensure air quality does not degrade beyond the National Ambient Air Quality Standards (NAAQS) or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then it triggers this review process.

EPA has provided significance impact levels (SIL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted for NO_2, CO, and PM_{10} to determine if ambient impacts would be above the SIL and monitoring significance levels (MSL). For NO_X, the total NO_X emissions were modeled and then the maximum predicted impacts were converted to NO_2 using the Ambient Ratio Method (ARM) for comparison SIL and MSL. If impacts are above the SIL, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the SIL. If a ROI is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a ROI, no further air quality analysis is required for the Class II area.

The ROI is used to determine the distance out to which nearby sources need to be reviewed for inclusion in the NAAQS and increment modeling. The nearby source inventories for each pollutant that exceeded the SIL were obtained from the AQD using the determined ROI. Inventory sources included in the full impact analysis are generally sources that are within the ROI plus 50 km.

AERMOD (07026) was used for the modeling analyses. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and is the preferred model for these analyses. The modeling analysis was performed using the regulatory default models settings, which include stack heights adjusted for stack-tip downwash and missing data processing.

Source and building elevations were obtained from engineering elevation drawings. Receptor terrain elevations entered into the model were the highest elevations extracted from USGS 7.5 minute digital elevation model (DEM) data of the area surrounding the proposed site. For each receptor elevation, the maximum terrain elevation associated with the four DEM points surrounding the receptor will be selected.

In order to account for building wake effects, direction-specific building dimensions used as input to the model were calculated using the algorithms of the Building Profile Input Program (BPIP). BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, and the Building Downwash Guidance document while incorporating the enhancements to improve prediction of ambient impacts in building cavities and wake regions.

As described in the *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits*, meteorological data was derived from Oklahoma Mesonet surface data, National Climactic Data Center (NCDC) Integrated Surface Hourly (ISH) data, and FSL/NCDC Radiosonde upper air data. Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma and supported by the taxpayers of Oklahoma. The model runs were performed using 2001-2005 meteorological data using NWS surface observations from Tulsa, upper air measurements from Springfield, Missouri, and adjusting the surface data using the Oklahoma Mesonet data from Pryor, OK. The 2001-05 data set used in this analysis was provided by the AQD.

Three Cartesian grids for the modeling analyses were defined as follows:

1. A Fence Line Grid containing receptors spaced at 50 meter intervals along the facility fence line.
2. A Fine Grid containing receptors spaced at 100 meter intervals extending approximately 3.0 km from the fence line, exclusive of the Fence Line Grid.
3. A Coarse Grid containing receptors spaced at 1.0 km intervals extending approximately 17.0 km beyond the Fine Grid.

Significance Analyses

In addition to emissions from normal operations, the modeling analysis included emissions from startup and shutdown periods of operation. The combustion turbines operate under several different types of startup conditions, as described below. During these startup and shutdown periods, the combustion turbine typically exhibits NO_X and CO emission levels greater than what is listed in the manufacturer's emission guarantee, which corresponds to normal operations. The facility has made very conservative estimates regarding the duration of each of these startup events and their expected emission rates based on a combination of manufacturer-provided data and the operating performance of the existing turbines. Emissions of other criteria pollutants, such as PM_{10}, SO_2, and VOC, are considered unaffected by startup/shutdown conditions. Modeled NO_X and CO emissions are based on the specific event durations.

For NO_X, the total annual emissions for a single turbine including startup and shutdown emissions are 164.38 TPY and were average over an 8,760 hour operating year. The modeled PM_{10} emission rates are based on the maximum hourly emission rate of 6.59 lb/hr. The modeled one hour CO emissions represent the maximum amount of emissions released over a one hour period, which corresponds to a shutdown period. The modeled eight hour CO emission rates represent the maximum amount of emissions released over an eight hour period. This would correspond to a cold start (four hours), followed by four hours of normal operation. A summary of eight hour CO emissions calculation is shown on the following page.

CO EMISSION SUMMARY (8-HRAVERAGING PERIOD)

Operating Mode	Duration (hours)	Emission Rate (lb/hr)	Total Emissions (lbs)
Cold Startup	4	399	1,596
Normal Operations	4	64	256
Total	8	--	1,852[1]

[1] - This corresponds to an 8-hr average emission rate of 231.5 lb/hr. Modeling was conducted at 304.75 lb/hr. If the facility is in compliance at the higher emission rate the facility will be in compliance at the lower emission rate.

The remaining sources, including the cooling tower, auxiliary boiler, and fuel gas water bath heater are not affected by any startup/shutdown issues. The modeled emissions for these sources were based on the short term (lb/hr) emission rate. Source parameters for the proposed new units are based on the designs of the comparable existing units and are shown below.

Modeled Source Parameters

EU #	EU Description	UTM Coordinates (meters) East	West	Stack Height (m)	Stack Temp. Kelvin	Exit Velocity (m/s)	Stack Diameter (m)
1-03	Turbine No.3	295504	4011041	39.63	366	19.95	5.69
1-04	Turbine No.4	295535	4011041	39.63	366	19.95	5.69
2-02	Auxiliary Boiler No.2	295519	4011064	7.62	478	14.15	0.70
3-02	Fuel Gas Heater No.2	295281	4011093	4.27	383	9.75	0.52
6-02-1	Cooling Tower, Cell 1	295635	4010951	12.80	299	8.89	16.46
6-02-2	Cooling Tower, Cell 2	295635	4010968	12.80	299	8.89	16.46
6-02-3	Cooling Tower, Cell 3	295635	4010985	12.80	299	8.89	16.46
6-02-4	Cooling Tower, Cell 4	295635	4011002	12.80	299	8.89	16.46
6-02-5	Cooling Tower, Cell 5	295635	4011018	12.80	299	8.89	16.46
6-02-6	Cooling Tower, Cell 6	295635	4011035	12.80	299	8.89	16.46
6-02-7	Cooling Tower, Cell 7	295635	4011052	12.80	299	8.89	16.46
6-02-8	Cooling Tower, Cell 8	295635	4011068	12.80	299	8.89	16.46
6-02-9	Cooling Tower, Cell 9	295635	4011085	12.80	299	8.89	16.46

Modeled Source Emissions

EU #	EU Description	NO_X (Annual) (g/s)	CO (1-hour) (g/s)	CO (8-hour) (g/s)	PM_{10} (24-hr, Annual) (g/s)
1-03	Turbine No.3	4.73[1]	70	38.4	1.330
1-04	Turbine No.4	4.73[1]	70	38.4	1.330
2-02	Auxiliary Boiler No.2	0.30	0.63	0.63	0.043
3-02	Fuel Gas Heater No.2	0.34	0.05	0.05	0.013

[1] - Turbine NO_X emissions modeled are greater than what was permitted.

Modeled Source Emissions

EU #	EU Description	NO_X (Annual) (g/s)	CO (1-hour) (g/s)	CO (8-hour) (g/s)	PM_{10} (24-hr, Annual) (g/s)
6-02-1	Cooling Tower, Cell 1	----	----	----	0.050
6-02-2	Cooling Tower, Cell 2	----	----	----	0.050
6-02-3	Cooling Tower, Cell 3	----	----	----	0.050
6-02-4	Cooling Tower, Cell 4	----	----	----	0.050
6-02-5	Cooling Tower, Cell 5	----	----	----	0.050
6-02-6	Cooling Tower, Cell 6	----	----	----	0.050
6-02- 7	Cooling Tower, Cell 7	----	----	----	0.050
6-02-8	Cooling Tower, Cell 8	----	----	----	0.050
6-02-9	Cooling Tower, Cell 9	----	----	----	0.050

A summary of results from the significance analysis is shown below. For the PM_{10} 24-hour standard the emissions were modeled using five years of combined meteorological data. The PM_{10} 24-hour average emission result shown below is the sixth highest high over the five-year period modeled.

Class II Area Significance Analysis Results

Pollutant	Averaging Period	SIL $\mu g/m^3$	Max Impact $\mu g/m^3$	Full Impact Analysis Required?
NO_2	Annual	1	6.5	Yes
CO	1-hr	2,000	885.6	No
	8-hr	500	151.8	No
PM_{10}	24-hr	5	10.5	Yes
	Annual	1	0.8	No

As seen above, NO_2 (annual) and PM_{10} (24-hr) exceeded their respective SIL and requires a full impact analysis. The modeling results were then compared to the Class I area SIL. This was done to determine if a Class I Increment Analysis is required. If the Class I SIL were not exceeded within the modeling domain, then a Class I Area Increment analysis is not required.

Class I Area Significance Analysis Results

Pollutant	Averaging Period	SIL $\mu g/m^3$	Distance km	Full Impact Analysis Required?
NO_2	Annual	0.1	1.0	No
PM_{10}	24-hr	0.3	6.6	No
	Annual	0.2	0.5	No

The modeling results were then compared to the MSL. If the impacts from the proposed project exceed the MSL then the facility might be required to do pre-construction monitoring.

Monitoring Significance Level Comparison

Pollutant	Averaging Period	MSL $\mu g/m^3$	Max Impact $\mu g/m^3$
NO_2	Annual	14	7
CO	8-hr	575	152
PM_{10}	24-hr	10	11
VOC/Ozone	8-hr	100 TPY	50 TPY

The PM_{10} impacts exceed the MSL. However, since there is an existing monitoring site located approximately 2.3 km ESE of the facility, no pre-construction monitoring is required of the facility.

NAAQS Analysis

Significance results indicated that the furthest significance receptor for either NO_X or PM_{10} was located approximately 8 km from the plant, resulting in an ROI of 58 kilometers. The inventory source data provided by the AQD included review of major sources located 65 km from the plant, and minor sources within 10km. To complete the NAAQS Analysis, the proposed emissions from the facility were modeled simultaneously with the emissions from the NAAQS sources identified in the inventory provided by the AQD. A full list of the sources used in the modeling was provided in the application. Permit allowable emission rates were modeled for all short-term averaging periods. For annual averaging periods, the potential emissions were multiplied by an operating factor which was based on the past actual 2-year average of operating hours reported in the emission inventory data. The background concentrations were added to the modeled concentration for comparison with the NAAQS.

Monitoring data from the state's network of ambient monitors was utilized to develop background concentrations for use in NAAQS analysis. The Mayes County monitors were used as the most representative monitoring data and are approximately 2.3 km ESE of the facility.

NAAQS Background Concentrations

	Averaging	Concentrations		Monitor	
Pollutant	**Period**	**ppm**	**$\mu g/m^3$**	**Site ID**	**Year**
NO_2	Annual	0.004	8	400979014	2007
PM_{10}	24- hr[1]	----	58	400979014	2007-5

[1] – The fourth highest concentration over the most recent three years of data.

The results of the NAAQS analysis, after accounting for the ARM and including background concentrations are summarized below.

NAAQS Analyses Results

Pollutant	Averaging Period	Impact $\mu g/m^3$	Background $\mu g/m^3$	Total $\mu g/m^3$	NAAQS $\mu g/m^3$
NO_2	Annual	18	8	26	100
PM_{10}	24- hr[1]	93	58	151	150

As seen above, the modeling predicts a single exceedance of the PM_{10} NAAQS. As described in the NSR/PSD Workshop Manual, when an exceedance is predicted at one or more receptors in the impact area, the applicant must:

> "[..] determine if the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of the predicted violation, and at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation."

The modeling was reviewed to determine if the emissions from the Chouteau Plant expansion had a significant impact at the specific receptor when the modeled exceedance occurred. The impact of the PM_{10} emissions from the Chouteau Plant expansion was less than 5 $\mu g/m^3$ (3.1 $\mu g/m^3$) at the specific receptor when the modeled exceedance occurred. Therefore, the emissions from the modification of the Chouteau Plant do not cause or contribute to the modeled PM_{10} NAAQS violation.

PSD INCREMENT ANALYSIS

The PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The major source baseline date depends upon the county in which the facility is located and on the pollutant in question. Sources that contribute to emissions increases after the baseline date are obtained from the AQD, and total facility-wide potential emissions are modeled simultaneously with the PSD Increment inventory sources provided by the AQD. As with the NAAQS analysis, permit allowable emission rates were modeled for all short-term averaging periods. For annual averaging periods, the potential emissions were multiplied by an operating factor which was based on the past actual 2-year average of operating hours reported in the emission inventory data.

Class II PSD Increment Analyses Results

Pollutant	Averaging Period	Impact $\mu g/m^3$	Allowable $\mu g/m^3$
NO_2	Annual	15	25
PM_{10}	24- hr[1]	380	30

The increment modeling was reviewed to determine if the emissions from the Chouteau Plant expansion had a significant impact at the specific receptor when the modeled exceedance occurred. The impact of the PM_{10} emissions from the Chouteau Plant expansion was less than 5 $\mu g/m^3$ at the specific receptors when the modeled exceedance occurred. Therefore, the emissions from the modification of the Chouteau Plant do not cause or contribute to the modeled PM_{10} Increment violation.

Class I Area Visibility Analysis

The nearest Class I areas are the Caney Creek Wilderness in western-central Arkansas, the Hercules Glades Wilderness in southwestern Missouri, and Upper Buffalo Wilderness located in north-central Arkansas. AECI strives to comply with the most current guidelines and utilized the method recommended by the Federal Land Managers (FLM) for Class I Area impact analysis. The FLM have proposed new guidance that uses the 10D Rule (Q/D<10). In this equation, Q is equal to the sum of the emission increases of NO_X, SO_2, and PM_{10} that will result from the proposed project (in TPY). The variable D is the distance from the source to the Class I Area (in km), and must be greater than 50 km. If the calculated Q/D value exceeds 10, then a Class I area analysis evaluating Air Quality Related Values (AQRV) (deposition and visibility) must be conducted. Otherwise, no additional analyses are required. As shown below, since Q/D is less than 10 no AQRV analyses need to be conducted.

10D Rule Screening Analysis

	Distance	**Emissions**	
Class I Area	**km**	**TPY**	**Q/D**
Caney Creek	200	486	2.4
Hercules Glade	215	486	2.3
Upper Buffalo	260	486	1.9

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, Visibility

Mobile Sources

The facility currently employs no more than 30 workers. The expansion will not result in additional employees beyond a total of 30, and will therefore result in a negligible increase in mobile source emissions.

Growth Impacts

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. As mentioned previously, staffing of new permanent jobs is expected to be limited and the facility will likely employ fewer than 30 individuals over all shifts. As a result, additional growth impacts are expected to be minimal.

Soils and Vegetation Impact

The following discussion will review the project's potential to impact its agricultural surroundings based on the facility's allowable emission rates and resulting ground level concentrations of NO_2, VOC, CO, and PM_{10}.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. PM can impact vegetation through deposition and removal. The effects of this deposition include depleting nutrients in soils, damaging sensitive forests and farm crops, and affecting ecosystem diversity. These effects are generally associated with the removal of large quantities of soils from ecosystems, not with the possible addition of smaller quantities of fine materials. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. As described previously, the Chouteau plant expansion is not predicted to cause or contribute to a violation of the NO_2 or PM_{10} primary NAAQS. As a result, compliance with the secondary NAAQS is also expected.

At the levels of CO that occur in urban air, there are no detrimental effects on materials or plants, however human health may be adversely affected at such levels. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents, and extends to agricultural soil. Modeled CO impacts do not trigger modeling significance levels (MSLs). As a result, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed power plant.

Visibility Impairment

A screening analysis was conducted in order to evaluate the Chouteau Plant expansion's impact on Class II visibility. VISCREEN, the screening tool recommended for Class I visibility screening analyses, was used per guidance provided by the Oklahoma DEQ. In the absence of any guidance on the topic of Class II visibility screening analysis, default values and screening parameters for Class I visibility screening were used as recommended by U.S. EPA.

VISCREEN allows for two levels of visibility impact screening. Level 1 screening involves a series of conservative calculations designed to identify those emissions sources that have little potential for adversely affecting visibility. If visibility impairments are indicated, a Level 2 analysis, which allows for modification of default parameters including meteorological data, is performed. Both Level 1 and Level 2 analyses were performed for this study.

The default meteorological conditions of F-stability and 1 m/s wind speed were used. For emission rates, only annual emissions of NO_2 and PM_{10} from the combustion turbines were input into the model. The default values were chosen for primary NO_2, soot, and primary sulfate emissions. A background visual range of 40 km was used.

Based upon a geographic analysis of the local area, the closest large population center (Pryor, OK), is located 10 km from the Chouteau Plant. This distance was used for source-observer input distance. In addition, since this Class II analysis does not involve a formal Class I area boundary, a Class II boundary was selected (per DEQ guidance) extending from 1 km to 10 km from the source.

VISCREEN analyzes a matrix of conditions for regions within and outside the Class I area boundaries (in this case, the "Class II" boundaries). This matrix includes forward scattering and backward scattering impacts viewed against the sky and the surrounding terrain (e.g., mountains, hills, etc.). The forward scattering case assumes that the sun is in front of the observer at an angle of 10° above the horizon. The backward scatter case assumes that the sun is at the observer's back at an angle of 140° above the horizon.

Results from the VISCREEN model are expressed in terms of perceptibility (ΔE) and contrast. The EPA default Class I screening criteria for perceptibility and contrast are 2.0 and 0.05, respectively. For a Class II analysis, the AQD guidance suggests that 3 × the screening criteria be used, resulting in perceptibility and contrast thresholds of 6.0 and 0.15.

VISCREEN RESULTS

		Azimuth	Dist.	Alpha	ΔE		Contrast	
Background	**(degrees)**	**(degrees)**	**(km)**	**(degrees)**	**Critical**	**Plume**	**Critical**	**Plume**
SKY	10	10	4.8	159	6	6.793	0.15	0.004
SKY	140	10	4.8	159	6	2.574	0.15	-0.039
TERRAIN	10	1	1	168	6	9.697	0.15	.111
TERRAIN	140	1	1	168	6	2.089	0.15	.077

As seen from these results, the perceptibility threshold is marginally exceeded when viewed against a sky background, and exceeded when viewed against terrain. Although the modeled visibility impact is greater than 3 × the EPA default Class I threshold, AECI believes that the predicted impact will not result in actual visibility impairment.

Endangered Species Act (ESA)

An endangered species analysis was conducted for Mayes County in order to demonstrate compliance with the ESA. Based upon the latest County Species List for Mayes County, OK, there are five species present on the county species list for Mayes County:

- the American peregrine falcon (bird),
- Arkansas darter (fish),

- bald eagle (bird),
- Ozark cavefish (fish), and
- piping Plover (bird, endangered).

Of these five species, the U.S. Fish and Wildlife Service's (FWS) critical habitat mapper does not indicate the presence of any critical habitat in Mayes County. As a result, the proposed expansion at the Chouteau plant is not expected to adversely affect endangered species.

SECTION VI. 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. Compliance with the NAAQS is addressed in the "PSD Review" section.

OAC 252:100-5 (Registration, Emission Inventory, And Annual 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. This facility has recently submitted the required emission inventories and has paid the applicable or fees.

OAC 252:100-8 (Major Source/Part 70 Permits) [Applicable]
<u>Part 5</u> includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) 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 single HAP that the EPA may establish by rule

Emissions limitations have been established for each emission unit based on information from the permit application and Permit No. 98-270-TV (PSD) (M-2).

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release that results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in 252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

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]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. The units listed below are subject to the requirements of this subchapter and will be in compliance as shown in the following table.

Equipment	Max. Heat Input (MMBTUH) (HHV)	Allowable PM Emission Rate (lb/MMBTU) (HHV)	Potential PM Emissions (lb/MMBTU) (HHV)
Each New Turbine	1,882	0.17	<0.01
Each Existing Turbine	1,783	0.17	<0.01
Auxiliary Boiler (2)	33.5	0.45	0.01
Fuel Gas Water Bath Heater (2)	18.8	0.52	0.01
Backup Generators (2)	<10	0.60	0.10
Diesel Fire Water Pump (2)	<10	0.60	0.31

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. All of the emission units are subject to this subchapter. The turbines, Auxiliary Boiler, and Fuel Gas Water Bath Heater will assure compliance with this rule by ensuring “complete combustion” and utilizing pipeline-quality natural gas as fuel. The Backup Diesel Generator and the Diesel Fire Water Pump assure compliance with this rule by ensuring “complete combustion.”

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. No activities are expected that would produce fugitive dust beyond the facility property line.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels, the limit is 0.2 lb/MMBTU heat input, three-hour average. The permit will require the new/existing turbines to be fired with pipeline-grade natural gas with SO_2 emissions of 2.2/2.0 lb/hr, which is equivalent to 0.001 lb/MMBTU. The auxiliary boiler and fuel gas heater emissions are approximately 0.0009 and 0.004 lb/MMBTU, respectively. The backup diesel generator and diesel fire water pump fire diesel fuel with a maximum sulfur content of 0.05 % by weight. This fuel will produce emissions of approximately 0.05 lbs/MMBTU, which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTU. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, and equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitoring requirement, so the turbines do not require such monitoring.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits emissions of NO_X from new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to a three-hour average of 0.2 lb/MMBTU. Listed below is the 3-hr average emission limit (lb/hr) of NO_X for each combustion turbine and the equivalent emission rates (lb/MMBTU) based on the maximum heat input, which are below the standard of 0.2 lb/MMBTU. However, for operational flexibility, the permit will establish a limit based on the Subchapter 33 allowable of 0.2 lb/MMBTU, three-hour average. The Auxiliary Boiler, Fuel Gas Water Bath Heater, Backup Diesel Generator, and the Diesel Fire Water Pump are below 50 MMBTUH heat input and are, therefore, not subject to this regulation.

	MMBTUH	**lb/hr**	**lb/MMBTU**
New Turbines	1,882	15.25	0.012
Existing Turbines	1,783	86.70	0.050

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The anticipated diesel tanks will be below the 1.5 psia threshold.
Part 5 limits the VOC content of coatings used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions of VOC. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of VOC.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
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 Area of Concern (AOC) has been designated anywhere in the state, 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 Emissions 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	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SECTION VI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility is a listed source as a fossil fuel-fired electric plant of more than 250 MMBTU heat input with emissions greater than 100 TPY. PSD review has been completed in Section IV.

NSPS, 40 CFR Part 60 [Subparts Dc and GG are Applicable]
Subpart Da, Electric Steam Generating Units. This subpart affects electric steam generating units with a design capacity greater than 250 MMBTUH constructed after September 18, 1978. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV), and therefore are not subject to Subpart Da. Furthermore, since the turbines are subject to NSPS, Subpart GG, they would be exempt from this subpart as per § 60.40a(b).

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects electric steam generating units with a design capacity greater than 100 MMBTUH constructed after June 19, 1984. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV), and therefore are not subject to Subpart Db. Furthermore, since the turbines are subject to NSPS, Subpart GG, they would be exempt from this subpart as per § 60.40b(i).

Subpart Dc, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. For gaseous-fueled units, the only applicable standard of Subpart Dc is a requirement to keep records of the fuels used. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV). However, since the turbines are subject to NSPS, Subpart GG, the duct burners are exempt from this subpart as per § 60.40c(e). The 33 MMBTUH (LHV) gas-fired auxiliary boilers are affected units as defined in the subpart since the heating capacity is above the de minimis level. Recordkeeping will be specified in the permit.

Subpart GG, Stationary Gas Turbines. This subpart affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Each of the new turbines has a rated heat input of greater than 10 MMBTUH and is subject to this subpart.

EPA guideline document EMTIC, GD-009 advises to use zero for the value of F with gas turbines. So, the lowest NO_X limit is 0.0075% or 75 ppmdv when Y = 14.4. The NO_X emission limitation for turbines EU 1-01 and 1-02 is 12 ppmdv at 15% O_2 and is therefore more stringent than the Subpart GG standards. Similarly, the NO_X emission limitation for proposed turbines EU 1-03 and 1-04 is 2 ppmdv at 15% O_2 and puts them at an even greater compliance margin compared to the Subpart GG standard. Performance testing by Reference Method 20 was required. Monitoring fuel for nitrogen content is not required if the owner or operator does not claim an allowance for fuel bound nitrogen per § 60.334(h)(2).

Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur or the exhaust gases shall not contain SO_2 in excess of 150 ppm. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted if the gaseous fuel is demonstrated to meet the definition of "natural gas" using either the gas quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or using representative fuel sampling data. The maximum total sulfur content of "natural gas" is 20 grains/100 SCF (680 ppmw or 338 ppmv) or less.

Subpart IIII, Stationary Compression Ignition Internal Combustion Engines. This subpart affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The existing backup diesel generator (EU 4-01) was manufactured prior to the applicability date of this subpart and is not subject to this subpart. However, the proposed backup diesel generator (EU 4-02) will likely have been manufactured after the April 1, 2006 date (for units procured after July 11, 2005). Therefore, the new unit will be subject to the requirements in Subpart IIII. It is expected that the unit will have a displacement of less than 30 liters and a heat input rating of 1,640.5 kW. According to the NSPS, this unit must meet the following emission limitations:

NSPS Emission Limits for Emergency Engines

NMHC + NO_X	**CO**	**PM**	**Opacity**		
g/kW-hr (lb/hr)	**g/kW-hr (lb/hr)**	**g/kW-hr (lb/hr)**	**Acceleration**	**Lugging**	**Peak**
6.4 (23.15)	3.5 (12.66)	0.2 (0.72)	20%	15%	50%

Similarly, the proposed emergency Fire-Water Pump (EU 5-02) will likely be subject to the emissions limitations found in Table 4 of Subpart IIII. Assuming a similar horsepower rating as the existing fire pump (EU 5-01 is 267 hp), the following limitations would apply:

NSPS Emission Limits for Fire Pump Engines[1]

NMHC + NO_X	**CO**	**PM**
g/hp-hr (lb/hr)	**g/hp-hr (lb/hr)**	**g/hp-hr (lb/hr)**
7.8 (4.59)	2.6 (1.53)	0.40 (0.24)

[1] **– Based on 2008 & earlier emissions.**

Subpart KKKK, Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU) per hour, based on the higher heating value of the fuel, that commenced construction, modification, or reconstruction after February 18, 2005. The new stationary combustion turbines in this permit were constructed prior the applicability date of this subpart and therefore are not subject to this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, concerns only process streams that contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Subpart ZZZZ is Applicable]
Subpart YYYY, Stationary Combustion Turbines. This subpart was promulgated on March 5, 2004 and affects stationary combustion turbines that are located at major source of HAP. On August 18, 2004, the EPA stayed the effectiveness of two subcategories of this subpart: lean premix gas-fired turbines and diffusion flame gas-fired turbines pending the outcome of EPA's proposal to delete these subcategories from the source category list. This facility is a major source but the turbines located at this facility are in the lean pre-mix gas-fired turbine category and are expected to be deleted from the source category list.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE with a site-rating greater than 500 brake horsepower and which are located at a major source of HAP emissions. The subpart establishes emission and operating limitations for each affected source. This facility is a major source of HAPs. Existing emergency stationary RICE are exempt from this subchapter. The existing emergency generator at this facility is exempt from this subpart. The new emergency generator is subject to this subpart and must meet the requirements of this part by meeting the requirements of 40 CFR Part 60, Subpart IIII, for compression ignition engines.

Subpart DDDDD, Industrial Boilers and Process Heaters. Subpart DDDDD regulated HAP emissions from industrial boilers and process heaters. In March, 2007, the DC Circuit Court of Appeals filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (less than 10 MMBTUH heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.

EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACTs. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. Until such time as more guidance is received, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

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

The turbines use a control device to meet an applicable emission limit and have the potential to emit greater than major source levels. However, the turbines are subject to a continuous monitoring requirement and are exempt from this part per § 64.2(b)(vi).

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable At This Time]
There will be no regulated substances used, stored or processed at the facility above threshold levels as a result of this project except possibly ammonia. If ammonia will be stored above the applicable threshold, the facility will need to comply with the requirements of this part by the date on which the regulated substance (ammonia) is present above the threshold quantity. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it will commence operation after November 15, 1990, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, U.S. EPA, has confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which can waive this requirement and has done so. The applicant submitted a Phase II Acid rain permit application on June 2, 2008.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
This part provides for allocation, tracking, holding, and transferring of SO_2 allowances.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
The facility shall comply with the emission monitoring and reporting requirements of this Part.

Acid Rain, 40 CFR Part 76 (NO_X Requirements) [Not Applicable]
This part provides for NO_X limitations and reductions for coal-fired utility units only.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are 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).

<u>Subpart A</u> 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.

<u>Subpart F</u> 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.

Conditions are included in the standard conditions of the permit to 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.

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.

SECTION VII. COMPLIANCE

Tier Classification and Public Review of Modified Construction Permit

This application has been determined to be Tier II based on the request for a construction permit for an existing major stationary source. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant has option to purchase the land.

The applicant published the "Notice of Filing a Tier II Application" and the "Notice of Tier II Draft Permit" in *The Daily Times* a daily newspaper in Mayes County on October 30, 2008. The "Notice of Filing a Tier II Application" stated that the application was available for public review at the Pryor Public Library located at 505 E Graham Ave., Pryor, Oklahoma and the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma. The "Notice of Tier II Draft Permit" stated that the draft permit was available for public review at the Pryor Public Library located at 505 E Graham Ave., Pryor, Oklahoma, the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma, and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/. No comments were received from the public.

This site is within 50 miles of the Oklahoma – Arkansas and Oklahoma – Missouri borders. The states of Arkansas and Missouri were notified of the draft permit. No comments were received from the states of Arkansas or Missouri.

This permit was approved for concurrent public and EPA review. The draft permit was forwarded to EPA for a 45-day review period. Since there were no comments received from the public the draft permit was deemed the proposed permit. The EPA submitted comments concerning the proposed permit in a letter dated December 8, 2009. Listed below are the comments from the EPA from the December 8, 2009 letter, responses from the applicant (AECI), and the final determination made by the AQD.

<u>EPA's 1st Comment</u>:

> "COMMENT 1: In the Preliminary Determination Summary, the State, in its analysis did not provide a detailed administrative record documenting appropriate best available control technology (BACT) determinations for the new emissions of nitrogen oxide (NO_X), particulate matter nominally 10 microns and less (PM_{10}), and carbon monoxide (CO). In particular, there is no comparison of emission rates/control units with other similar types of operations nationwide. Please provide the State's rationale for the BACT determinations and your analysis of federal /state /1ocal NSR permits, including an analysis of the technical and economic feasibility of available control technologies."

<u>Response from the Applicant</u>:

> "In the original permit application and in the draft permit, a number of control technologies were considered and determinations were made on either a technical or economic basis. Although a comparison to specific facilities was not included, the technologies selected in the BACT determinations for NO_X, CO, and PM_{10} are consistent with other RBLC entries for combined cycle turbines. EPA's comments make clear that they do not consider the emission levels proposed as BACT to be sufficiently stringent. As discussed in the responses below [to the remaining comments], the proposed emission limits represent the lowest emission rates the turbine manufacturer indicated these turbines could reasonably be expected to achieve. Further, it should be noted that the proposed units are of a similar vintage to the existing units constructed nearly ten (10) years ago.

> Despite the presence of RBLC entries indicating lower emission rates, AECI is not comfortable with reducing the proposed emission limits considering that the permit limits are enforceable for the life of the plant. AECI believes the permit limits are firmly within the RBLC range."

<u>AQD's Final Determination</u>:
The permit memorandum does contain a detailed analysis of BACT for NO_X, PM_{10}, and CO including an analysis of the technical and economic feasibility of available control technologies and also compares the originally established BACT levels to those established nationwide. However, after further review the BACT determinations have been revised based on the remaining comments from EPA.

<u>EPA's 2nd Comment</u>:

> "COMMENT 2: In the permit Special Condition No. 1, the proposed BACT used to control the emissions of NO_X from the new gas-fired combined cycle establishes an emission rate of 3 ppmvd at 15% O_2 annual average. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 2 ppmvd at 15% O_2 1-hr average. In addition, there are similar rates for other facilities in the Clearinghouse database with lower then 3.0 ppmvd limits on 1-hr average. Furthermore, the Texas Commission on Environmental Quality (TCEQ) has recently changed its BACT guidance for natural gas combustion turbines in combined cycle mode to be 2 ppmvd at 15% oxygen for NO_X, on a 24-hour average basis. A search of recent TCEQ air permits that have been issued for natural gas turbines as well as the EPA's RBLC revealed that in several permits, BACT for NO_X was the use of DLN combustors in combination with SCR. Please provide the State's rationale for why, after analyzing the technical and economic feasibility of available control technologies, a 2 ppmvd at 15% O_2 1-hr average NO_X limit cannot be achieved by this facility."

<u>Response from the Applicant</u>:

> <u>Initial Response</u>
> "While preparing the permit application, a review of RBLC search results and current TCEQ BACT determinations did indicate instances of new combined-cycle turbines operating at NO_X emission rates less than the proposed 3 ppmvd @ 15% O2. For several reasons, the Chouteau turbines cannot achieve a lower emission rate:
>
> - The turbines at the Chouteau plant, while new to the facility, are not newly manufactured units. The proposed Siemens V84.3A units are of late-1990s vintage/manufacture. While combined cycle turbines have achieved lower emission rates in the intervening ten (10) years through improved DLN burner efficiency and improvements in catalyst technology, the age of these units precludes them from meeting the BACT requirements established in recent years. The proposed emission level will require AECI to operate sufficiently

below 3 ppmvd NO_X to comply with the rolling average limitation. We believe the proposed limitation is at the point of testing the technological limits of the equipment and a more aggressive use of the SCR system would certainly increase the likelihood of creating higher levels of ammonia slip.

- The majority of the RBLC entries that commit to a 2 ppmvd NO_X limit also contain ammonia permit limits of 10 ppm, including the permit commented upon by the EPA, Gila Bend Power Generating Station (AZ-0038). As discussed in Comment 5, several of the most recent permits (such as the CPV Warren Plant, RBLC ID VA-0304, Permit Date 6/5/2007). AECI is already proposing a 10 ppm ammonia slip limit; based upon technical assessments provided by the turbine manufacturer, we do not believe further NO_X reductions can be achieved without operating the SCR system more aggressively (i.e. with greater levels of ammonia injection).

AECI believes that a twelve-month rolling average is sufficiently protective given that the NAAQS specifies an annual standard for NO_X. Even so, AECI is agreeable to a thirty (30) day rolling average to address the agency's concern."

<u>Letter dated December 30, 2008, addressing AQD letter to AECI concerning NO_X limit</u>:
"The NO_X emission rate in question (i.e. 3.0 PPM corrected to 15% O_2; as listed in Table 5-4 of the BACT analysis) was developed to represent a federally enforceable BACT permit limit over the life of the plant. Therefore, as allowed by the NSR Manual and upheld by the Environmental Appeals Board, the BACT emission rates should include an operating margin to allow a reasonable chance of achieving compliance on a consistent basis[1]. The information provided here is intended to address your request and to further support the NO_X limit as presented in the BACT and in the draft permit.

<u>Setting the PPM Limit for NO_X</u>
The main emission sources of the proposed 2-on-1 combined-cycle plant are the V84.3A combustion turbines with duct burners. You are correct in citing the new nomenclature as SCC6-4000F. The proposed units were constructed in the late 90s and it is our understanding that this model is no longer actively sold in the 60 Hz market. The proposed units are subject to the New Source Performance Standards found at 40 CFR Part 60 Subpart GG and are sited in Mayes County. Mayes County is an attainment/non-classified area for ozone.

These units, along with most other major components of the plant were originally purchased for installation in the state of Arizona. The project was eventually dropped by the original owner and the equipment became available for purchase on the secondary market. Attachment 1 to this submittal is from the equipment guarantee to the original owner. Please note that the NO_X guarantee is for 2.5 PPM @ 15% O_2 and for "new and clean" equipment.

Associated has been advised that an additional row of catalyst would be required to continuously achieve an emission rate in compliance with the suggested limit of 2.0 PPM NO_X @ 15% O_2. We are working on the incremental cost adder on a dollars-per-ton basis to determine the financial impact of controlling to the lower limit. At a minimum, the relevant cost factors will include a) the need for increased catalyst surface area, b) power loss due to increased back-pressure on the system, c) the increased cost of adding more ammonia, and d) the cost of purchasing replacement power due to the increase in unit heat rate.

While the financial impact is important to AECI and our member-owners, of notable consequence is the increase in emissions that would result from adding another obstruction (i.e. catalyst) to the effluent gas stream. The additional row of catalyst will increase the back-pressure to the system and force the system operator to burn more fuel to achieve the same electrical output from the generator. The increase in heat rate will result in an increase of all emissions on a lb/MWh basis as well as forcing AECI to generate or purchase electricity from a higher emitting source. AECI owns 38% of GRDA Unit 2 located upwind approximately 2.4 (linear miles) from the Chouteau facility. It is quite possible that the lost megawatts from the Chouteau facility would be replaced with energy dispatched from GRDA Unit 2. The average emission rate for GRDA unit 2 during all of 2007 was 154 PPM NO_X - or, about 7,700% higher than the suggested permit limit of 2.0 PPM for the Chouteau project. Associated is working to obtain the information regarding the heat rate penalty as expeditiously as possible.

In your letter you also mention the limitations of monitoring NO_X at these low levels. To this point, we believe that there are two factors that may introduce error into the CEM readings. These factors have less impact where the instruments are spanned at much higher levels, but at lower spans may interject a significant degree of uncertainty. The NO_X CEMS at Chouteau would be monitored per instrumental test Method 7E as described in 40 CFR Part 60 Appendix A-4. The method indicates process sensitivity as high as 2% of the instrument span. Where facilities must monitor very low levels of stack pollutants, the instrumentation department prefers to set the span as high as possible. To meet the annual requirement to monitor more than 50% of hourly emissions at or above 20% of instrument span (and less than 80% of span), we would expect to set the upper limit of the analyzer to 9 ppm for a limit of 2 or 3 ppm NO_X. Therefore, the implied error of the method could be as high as 0.18 PPM for a span set at 9 PPM. This would be almost 10% of the permit limit were it set at 2 PPM.

Similarly, Appendix A of 40 CFR Part 75 at 5.1.4(b) stipulates that EPA protocol reference gases must have a producer-certified uncertainty of no more that 2.0 percent of the certified concentration. Again, the implied error is 0.18 PPM if the high span gas is set at 9 PPM. The cumulative uncertainty due to allowed measurement error (i.e. Method 7E and EPA Protocol reference gases) would be 0.36 PPM - nearly 20%

of a permit limit at 2 PPM and almost twice the measurement error if one were to assume a permit limit of 3 PPM.

Averaging Time

To begin addressing the concern regarding the averaging period of the NO_X limit, AECI identified the Blythe facility located in the Mohave Desert Air Quality Maintenance District (MDAQMD) in California[2]. The Blythe facility is nearly identical to the proposed project at Chouteau. The facility was permitted at 2.5 PPM NO_X (corrected to 15% O2) on a three (3)-hour average basis. To evaluate the performance of the unit with respect to permit limit, we downloaded the most recent quarterly CEM report from the EPA web site at http://camddataandmaps.epa.gov/gdm/ and corrected the hourly NO_X emissions to 15% O_2. We then compared the hourly data to the permit limit of 2.5 PPM and the suggested and draft limits of 2.0 and 3.0 PPM, respectively. The results are listed in the table below:

Table 1 – Blythe Units 1 and 2 (Blythe, CA)

Blythe Unit	Permit Limit (NO_X PPM[1])	Hours of Valid QA NO_X Data	Hours > Permit Limit	Hours > 2 PPM[1]	Hours > 3 PPM[1]
1	2.5	1,301	102	1,287	43
2	2.5	1,194	80	1,193	46

[1] Corrected to 15% O_2 on a 1-hour basis.

While one might argue that the facility was only concerned with meeting the limit of 2.5 PPM on a 3-hour basis, we believe that the data is still instructive. Considering the comparison of emissions data to the higher limit of 2.5 PPM, it is apparent that the facility struggled to meet the limit on a continuous basis. It is also instructive to note the magnitude of many of these hours where unit emissions are >2.5 PPM. This information is included electronically with this transmittal.

It is the goal of AECI to comply with the permit conditions one-hundred percent of the time. We do not believe it is wise to create a situation where the ODEQ Enforcement Section is faced with continuously applying enforcement discretion toward a facility that is not capable of continuously achieving a federally enforceable permit limit.

Summary

Associated is providing this initial transmittal to respond to the Notice of Deficiency dated December 23, 2008. As indicated above, AECI is investigating the financial and environmental impacts of further reducing NO_X emissions to 2.0 PPM @ 15% O_2. We maintain that the limit of 3.0 PPM @ 15% O2 as presented in the draft permit is already at the threshold at which the facility can comply on a continuous basis. Further, AECI believes that the draft permit limit is sufficiently protective of the NAAQS and is not a major consumer of increment. At this time, we would like to request that the ODEQ AQD advise AECI of further data collection (i.e. similar to the Blythe analysis or other such efforts) that would be useful for your determination."

AQD's Final Determination:

Even though the specific facility that is referenced in the EPA comment was not built and is not operating, there are other facilities in the RBLC database that do have a NO_X emission limit of 2.0 ppmdv @ 15% O_2, 1-hr average which are operating. After review of all the data submitted, there is not enough data to indicate that the NO_X emission limit of 2.0 ppmdv @ 15% O_2, 1-hr average is not technically or economically infeasible. The BACT analyses submitted by the applicant indicate that the overall cost effectiveness of controlling NOX emission to 2 ppmdv with the use of an additional row of catalyst is approximately $2,000/ton. Therefore, the permit has established 2.0 ppmdv @ 15% O_2, 1-hr average as the BACT emission limit for this facility.

EPA's 3rd Comment:

> "COMMENT 3: In the permit Special Condition No.1, the proposed BACT used to control the emissions of CO from the new gas-fired combined cycle establishes an emission rate of 10 ppmvd at 15% O_2 annual average. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 4 ppmvd at 15% O_2, 3-hr average. In addition, there are similar rates for other facilities in the Clearinghouse database with lower then 4.0 ppmvd limits on 3-hr average. Please provide the State's rationale for why, after analyzing the technical and economic feasibility of available control technologies, a 4 ppmvd at 15% O_2 1-hr average CO limit cannot be achieved by this facility."

Response from the Applicant:

> As presented in the attached economic analysis, Catalytic Oxidation is considered economically infeasible. Although other facilities have committed to 4 ppmvd CO limits based upon good combustion practices as BACT, discussions with the turbine manufacturer indicated that CO emission levels lower than 10 ppm cannot be guaranteed for the entire operating range. Based on stack testing from similar combustion turbines in AECI's generation fleet, we believe that we can achieve a CO emission limit of 5 ppmvd at 75% of the load range and above. Below 75% load, CO emissions may be expected to climb as the burner flame is more dependent upon the more stable (but less efficient) pilot flame and less dependent upon the lower emitting pre-mix flame.
>
> The new combustion turbine NSPS at 40 CFR 60 Subpart KKKK (note: these older units are subject to Subpart GG) appropriately recognizes that the emissions profile of such units can be considerably different at lower loads. For natural gas fired combustion turbines > 850 MMBTUH, the NSPS at Subpart KKKK assigns an emission rate (maximum) of 15 ppm NO_X for loads > 75% of peak load. At loads less than 75%, the turbine may emit up to 96 ppm NO_X. This amounts to a difference of 640% percent from one load range to the other for a pollutant with a much tighter ambient standard than CO.

Historically, AECI’s combined cycle gas plants have operated between the morning-evening peak cycle. However, this is changing with the inclusion of wind generation on the AECI system. Because of the unpredictable nature of wind generation and to maintain a stable supply of electricity on the grid, AECI must “chase” the output from the wind farms with output from prompt-response resources. For AECI, this means regulating output from our gas fleet to stabilize the impact of the wind farms on the distribution system. This may be accomplished with either simple or combined-cycle units and must be addressed around the clock. The combined-cycle units at the Chouteau facility are a better option than peaking units for chasing wind generation. This is true both environmentally and economically.

Environmentally Preferred:
With the combined-cycle units at the Chouteau plant, AECI can reduce consumption of fuel by backing down the combustion turbine output while still maintaining operation of the steam turbine. This is not possible with a simple-cycle gas turbine EGU. At a combined-cycle plant, the heat recovery steam generating (HRSG) units greatly increase the efficiency of the plant. This means that the facility can put out more electricity per unit of pollutant. This is true because the steam turbine operates from the waste-heat captured at the HRSGs and can generate electricity without emitting pollutants. Further, because the combined cycle unit has a selective catalytic reduction (SCR) system to control NO_X emissions, these units can operate at a lower lb/MWh than can a simple-cycle gas turbine peaking unit that does not have SCR.

In addition, it is better (for the environment) to reduce the fuel consumption on a unit that is operating at maximum efficiency (e.g. a combined-cycle unit at base load) than to start up a cold peaking unit that will create its highest emissions during startup.

Economically Preferred:
By balancing the system output from the wind farms with a combined-cycle plant vs. a less efficient peaking plant, AECI should realize a lower $/MWh charge that will help keep rates as low as possible for our member-owners. A 2007 survey of AECI's member systems revealed 46 percent of respondents live in households earning annual gross incomes of $40,000 or less, and 32 percent are age 65 or older. About 17 percent live in households earning $20,000 or less. The survey also revealed 43 percent of members earning $40,000 or less pay on average more than $100 per month for electricity alone.

Summary:
Low load operations will be relatively infrequent and will typically occur only between the evening-morning peak (e.g. between 10PM and 8AM) and to avoid elevated startup/shutdown emissions and equipment startup penalties (e.g. from the effects of metal fatigue over time, lower efficiency at ramp-up, etc.) from brief unit shutdowns when the generation is not needed. In addition, lower load operations may occur as system dispatchers work to counteract the effect of wind generation and stabilize the grid.

> AECI proposes to limit emissions of CO from the proposed units to 5 ppm at loads $\geq$ 75%. At loads < 75%, CO emissions would be allowed without condition except where operation is limited by the startup and shutdown conditions found at Specific Condition 1.d and 1.e. Low load operations shall not be less than 40% of the rated unit load of the combustion turbine in question. Alternatively, AECI proposes to maintain the limit of 10 ppm CO as written in the draft permit."

AQD's Final Determination:
Again, the specific facility that is referenced in the EPA comment was not built and is not operating. However, there are other facilities in the RBLC database that do have lower CO emission limits which are operating but these facilities are permitted with the requirement for oxidation catalyst. Based on the information submitted by the applicant, it was determined that installation of an oxidation catalyst is considered economically infeasible for this particular facility at approximately $9,000/ton. The applicant submitted data from the turbine manufacturer guaranteeing an emission rate of 8 ppmdv @ 15% O_2. Therefore, after taking into account the EPA's comments and responses from the applicant AQD has established the CO emission limit at 8 ppmdv @ 15% O_2, 3-hr average.

EPA's 4th Comment:

> "COMMENT 4: The EPA is concerned that no short term emission limits based on 3-hr or 24-hr averaging periods for VOC and PM_{10} have been included in the draft permit. The EPA believes that short-term limits are necessary to ensure protection of the NAAQS and to adequately assess and protect increment consumption. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 4 ppmvd at 15% O_2 3-hr average for VOC and 0.011 lb/mmBtu 3-hr average. Please provide the State's rationale for why, short term limits are not achievable for VOC and PM_{10}."

Response from the Applicant:
AECI is willing to establish PM_{10} and VOC emission limits on a three (3) hour average basis. The averaging times for the test methods (i.e. methods 5, 17, or 201 and 202 for PM_{10} and method 25 for VOC) are on a three (3) hour basis (i.e. three one (1) hour runs equals one test). Compliance with the applicable test method and a result equal to or less than the permit limit will equate to compliance with the emission limit in the permit.

AQD's Final Determination:
Based on EPA's comment and response from the applicant the PM_{10} and VOC emission limits were based on a 3-hr average.

EPA's 5th Comment:

"COMMENT 5: ODEQ should consider permit conditions to reduce the ammonia slip from the SCR used by the facility to control NO_X. According to the RBLC database, some recently approved combined cycle projects with NO_X limits of 2.0 ppm also included Ammonia (NH_3) limits of 5 ppm in those determinations to address ammonia slip. However, such limits are not necessarily required by the PSD regulations. With the use of the SCR, the facility may consider adding an enhancer to the ammonia, in its pure form, which tends to reduce the ammonia slip and utilizes ammonia better than other processes. Another process would be to mix the ammonia with urea or with urea and water. In either case, the urea would act as a catalyst, and the mixture would tend to be more effective than its components alone.

In addition, the "Technical Support Document for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule): Reconsideration Notice of Proposed Rule," December 2005, states that recent SCR technology developments have emphasized minimization of ammonia slip, along with SO_2-to-SO_3 conversion levels. The new SCR installations are routinely being designed to maintain ammonia slip at a 2 to 3 ppmv level (see 7 referenced documents within the TSD for further information on the related technology)."

Response from the Applicant:

"As discussed in the notes to Comment 2, the Chouteau units are not newly manufactured turbines. Maintaining low NO_X concentrations potentially requires very aggressive use of ammonia in the SCR system, as in the case of the Chouteau turbines. Most combined-cycle turbines that commit to 2-3 ppmvd NO_X emission levels by necessity require relatively high limits for ammonia slip (5-10 ppm). Although newer SCR designs are optimized to reduce ammonia slip, it is only the most recent entries that contain very low limits on both NO_X and Ammonia. Older projects (pre-2005) that commit to 2-3 ppmvd NO_X and 5 ppm Ammonia slip were either not constructed, or are located in California (and are more reflective of LAER and not BACT). Based upon the assessment of the manufacturer, 10 ppm Ammonia slip is the lowest level attainable while maintaining 3 ppmvd NO_X. Given the age of the turbines, this ammonia level should be considered the best achievable emission rate."

AQD's Final Determination:

While ammonia is not regulated by PSD, it could be regulated by state BACT if the emissions exceeded 100 TPY but they are less than 100 TPY. There is no documentation that indicates that use of urea with anhydrous ammonia would act as a catalyst and increase the reduction efficiency of anhydrous ammonia. The seven reference documents referenced by EPA are not accessible through the EPA web site and are generally related to SCR where control of NO_X is not as stringent as the limits established by the current permit. Based on the applicant's comments and other available data the ammonia emission limits listed in the proposed permit have not been changed.

Fees Paid
Construction permit application fee of $2,000.

SECTION VIII. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Associated Electric Cooperative, Inc.
Chouteau Power Plant **Permit No. 2007-115-C (M-1) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on July 1, 2008 and all supplemental materials. The Evaluation Memorandum dated January 20, 2009, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

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

EUG 1. Electric Generating Units.

Emission limits and standards for Emission Units (EUs) 1-01 and 1-02 (Turbines with Duct Burners); The emission limits for each EU include but are not limited to the following:

Pollutant	lb/hr	TPY[3]	ppmvd[1]	lb/MMBTU[5]
NO_X	86.70[2]	379.75	12[3]	0.20[2]
CO	59.00	258.42	10	
VOC	4.99	21.87		
SO_2	1.00	4.38		
PM_{10}	6.24	27.33		0.0035
Ammonia	18.14[4]	79.46		
H_2SO_4	0.15[4]	0.61		

1 All concentrations are corrected to 15% O_2, per turbine.
2 Three-hour rolling average, based on contiguous operating hours.
3 Twelve-month rolling total.
4 24-hour average.
5 Based on HHV.

Emission limits and standards for EU 1-03 and 1-04 (Turbines with Duct Burners); The emissions limits for each EU include but are not limited to the following:

Pollutant	**lb/hr**	**TPY[3]**	**ppmvd[1]**	**lb/MMBTU[5]**
NO_X	15.25[2]	125.45	2.0[2]	0.20[4]
CO	51.32[3]	385.43	8.0	
VOC	5.27[3]	23.08		
SO_2	1.06[3]	4.62		
PM_{10}	6.59[3]	28.86		0.0035[6]
Ammonia	18.14[4]	79.46		
H_2SO_4	0.15[4]	0.61		

[1] All concentrations are corrected to 15% O_2, per turbine.
[2] One-hour average.
[3] Three-hour average.
[4] Three-hour rolling average, based on contiguous operating hours.
[6] 24-hour average.
[7] Based on HHV.

a. The turbines shall only be fired with natural gas as defined in New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

b. The turbines shall be equipped with dry low-NO_X burners. [OAC 252:100-8-34]

c. Emissions from each turbine and duct burner shall be controlled by a properly operated and maintained SCR. [OAC 252:100-8-34]

d. During startups and shutdowns, alternate short term emission limits apply to the combustion turbines. The short term emission limits for each combustion turbine during startup and shutdown are shown below:

Event	**Maximum Duration (hr)**	**NO_X Emissions (lbs/event)**	**CO Emissions (lbs/event)**
Startup	4	568	1,596
Shutdown	1	142	399

e. To demonstrate compliance with the startup and shutdown emission limits for NO_X, the permittee shall calculate the total emissions during the event and compare it to the table above. Startup ends when the turbine reaches normal operating mode and the SCR is operational. Compliance with the CO emission limits shall be based on the duration of the event and compliance with the NO_X emission limit. The existing units shall have ninety (90) days from the issuance of this permit to comply with this condition. [OAC 252:100-8-6(a)(1)]

f. Turbines 1-01, 1-02, 1-03, and 1-04 are subject to the NSPS for Stationary Gas Turbines, 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR § 60.330 to § 60.335]

i. § 60.332: Standard for nitrogen oxides
ii. § 60.333: Standard for sulfur dioxide
iii. § 60.334: Monitoring of operations
iv. § 60.335: Test methods and procedures
v. Monitoring of the fuel sulfur content is not required if the permittee can demonstrate that the gaseous fuel meets the definition of "natural gas" with a maximum total sulfur content of less than 20 grains/100 SCF (680 ppmw or 338 ppmv) or less using either a current valid purchase contract, tariff sheet, or transportation contract or representative fuel sampling. Monitoring of fuel nitrogen content under NSPS, 40 CFR Part 60, Subpart GG shall not be required unless the permittee claims an allowance for fuel bound nitrogen.

EUG 2. Auxiliary Boilers. Emission limits and standards for EU 2-01 and 2-02 include but are not limited to the following:

	NO_X		CO		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-01	2.36	10.34	5.02	21.99	0.54	2.37
2-02	2.36	10.34	5.02	21.99	0.54	2.37

a. The Auxiliary Boilers shall be equipped with low-NO_X burners. [OAC 252:100-8-34]

b. The Auxiliary Boilers shall only be fired with natural gas as defined in NSPS, 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

c. The permittee shall maintain a record of the amount of natural gas burned in the Auxiliary Boilers for compliance with NSPS, 40 CFR Part 60, Subpart Dc. [40 CFR § 60.48c(g) & § 60.13(i)]

EUG 3. Fuel Gas Water Bath Heaters. Emission limits and standards for EU 3-01 and 3-02 include but are not limited to the following:

	NO_X		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**
3-01	2.70	11.83	0.39	1.71
3-02	2.70	11.83	0.39	1.71

a. The Fuel Gas Water Bath Heaters shall only be fired with natural gas as defined in NSPS, 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

b. The permittee shall maintain a record of the amount of natural gas burned in the Fuel Gas Water Bath Heaters for compliance with NSPS, 40 CFR Part 60, Subpart Dc. [40 CFR § 60.48c(g) & § 60.13(i)]

EUG 4A. Backup Diesel Generator. Emission limits and standards for EU 4-01 include but are not limited to the following:

EU	NO_X		CO	
	lb/hr	**TPY**	**lb/hr**	**TPY**
4-01	52.80	13.20	12.10	3.03

a. EU 4-01 the Backup Diesel Generator shall not operate more than 500 hours per in any 12-month period. [OAC 252:100-8-6(a)(1)]

b. EU 4-01 the Backup Diesel Generators shall each be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

c. EU 4-01 the Backup Diesel Generators shall only be fired with fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

d. Replacement (including temporary periods of 6 months or less for maintenance purposes), of the internal combustion engine associated with the Backup Diesel Generator with an engine of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions:

   i. The permittee shall notify AQD in writing not later than 7 days in advance of the start-up of the replacement engine. Said notice shall identify the equipment removed and shall include the new engine make, model, and horsepower; date of the change, fuel usage, stack flow (ACFM), stack temperature (^oF), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location and any change in emissions.

   ii. Replacement equipment and emissions are limited to equipment and emissions which do not subject the engine/turbine to an applicable requirement not already included in this permit.

   iii. The permittee shall calculate the net emissions increase resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by Specific Condition 1, EUG 4A, (d). [OAC 252:100-8-6 (f)]

EUG 4B. Backup Diesel Generator Subject to NSPS, Subpart IIII. Emission limits and standards for EU 4-02 include but are not limited to the following:

EU	NO_X		CO		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4-02	23.15	5.79	12.66	3.16	0.72	0.18

a. EU 4-02 the Backup Diesel Generator is subject to the federal NSPS for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE), 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements:

[40 CFR § 60.4200 - § 60.4219]

What This Subpart Covers

i. 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

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

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

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

Fuel Requirements for Owners and Operators

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

Other Requirements for Owners and Operators

vi. 60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?

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

Compliance Requirements

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

Testing Requirements for Owners and Operators

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

Notification, Reports, and Records for Owners and Operators

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

General Provisions

xi. 60.4218 What parts of the General Provisions apply to me?

Definitions

xii. 60.4219 What definitions apply to this subpart?

b. EU 4-02 the Backup Diesel Generator shall not operate more than 500 hours per in any 12-month period. [OAC 252:100-8-6(a)(1)]

c. The Backup Diesel Generators shall each be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

EUG 5A. Emergency Fire Water Pump (Diesel). EU 5-01 is considered an insignificant activity and is limited to the following:

EU	Make/Model	Hp
5-01	Caterpillar/3306- A552598	267

a. EU 5-01 the Emergency Fire Water Pump shall not operate more than 500 hours in any 12-month period. [OAC 252:100-8-6(a)(1)]

b. EU 5-01 the Emergency Fire Water Pump shall be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

c. The Emergency Fire Water Pump shall only be fired with a fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

EUG 5B. Emergency Fire Water Pump (Diesel) Subject to NSPS, Subpart IIII. Emission limits and standards for EU 5-02 include but are not limited to the following:

EU	Make/Model	Hp
5-02	To Be Determined	267

a. EU 5-02 the Emergency Fire Water Pump is subject to the NSPS for Stationary CI-ICE, 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements: [40 CFR § 60.4200 - § 60.4219]

What This Subpart Covers

i. 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

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

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

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

Fuel Requirements for Owners and Operators

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

Other Requirements for Owners and Operators

vi. 60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?

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

Compliance Requirements

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

Testing Requirements for Owners and Operators

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

Notification, Reports, and Records for Owners and Operators

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

General Provisions

xi. 60.4218 What parts of the General Provisions apply to me?

Definitions

xii. 60.4219 What definitions apply to this subpart?

b. The Emergency Fire Water Pump shall not operate more than 500 hours in any 12-month period. [OAC 252:100-8-6(a)(1)]

c. The Emergency Fire Water Pump shall be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

d. The Emergency Fire Water Pump shall only be fired with a fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

EUG 6. Cooling Towers. EU 6-01 and 6-02 are considered insignificant activities and are limited to the following standards:

EU	Make/Model	No. of Towers
6-01	Psychometrics, Inc	9
6-02	To be determined	9

a. The Cooling Towers shall be equipped with drift eliminators. [OAC 252:100-8-34]

2. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines, auxiliary boiler, and fuel gas water bath heater continuously (24 hours per day, every day of the year). [OAC 252:100-8-6]

3. The turbines, Auxiliary Boiler, Fuel Gas Water Bath Heater, Backup Diesel Generator, and Emergency Fire Water Pump shall have a permanent (non-removable) identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

4. The permittee shall comply with all acid rain control permitting requirements and SO_2 emissions allowances and SO_2, NO_X, and O_2 continuous emissions monitoring and reporting. SO_2 emissions shall be monitored in accord with Part 75, Appendix D.

5. When monitoring shows concentrations or 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 for excess emissions including during start-up, shutdown, and malfunction of air pollution control equipment. Due to technological limitations on emissions during turbine start-up and shutdown, the owner or operator may submit an initial written notification of this condition and thereafter immediate notice and quarterly reports as provided in Paragraph 3.1(b)(2). Requirements for periods of other excess emissions include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

6. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities.

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

a. For stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or distillate fuel oil which are used exclusively for emergency power generation: records of hours of operation, size of engines, and type of fuel.
b. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of capacity of the tanks and contents.
c. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

7. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

a. Total fuel consumption for each turbine, the Auxiliary Boilers and the Fuel Gas Water Bath Heaters (monthly and 12-month rolling totals).
b. Operating hours for the Backup Diesel Generators and Emergency Fire Water Pumps (monthly and 12-month rolling totals).
c. For fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 1.
d. Diesel fuel consumption for the Backup Diesel Generators and Emergency Fire Water Pumps (12-month rolling totals).
e. CEMS data required by the Acid Rain program.
f. Records required by NSPS, Subparts Dc and GG.

8. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit (December 6, 2002), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]

9. Within 60 days of achieving maximum power output from each new turbine generator set (1-03 and 1-04), not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart GG for the combustion turbines and Subpart Dc for the auxiliary boiler. [OAC 252:100-8-6(a)]

10. The permittee shall conduct NO_X, CO, PM_{10}, and VOC testing on the new turbines (1-03 and 1-04) at the 60% and 100% operating rates, with testing at the 100% turbine load to include testing at both a 70% and 100% duct burner operating rate. NO_X and CO testing shall also be conducted on the turbines at two additional intermediate points in the operating range, pursuant to 40 CFR §60.335(c)(2). Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct sulfuric acid mist testing on the new turbines and duct burners (1-03 and 1-04) at the 100% operating rate of both the turbine and duct burner. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct formaldehyde testing on the new turbines (1-03 and 1-04) at the 50% and 100% operating rates, without the duct burners operating.

The permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, including back half condensable particulate. If the permittee reports USEPA Method 5 PM emissions as PM_{10}, testing using USEPA Method 201 or 201A need not be performed.

Performance testing shall be conducted while the new units are operating within 10% of the desired testing rates. Testing protocols shall describe how the testing will be performed to satisfy the requirements of the applicable NSPS. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.

The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 6C	Quality Assurance procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201/201A	Determination of PM_{10} Emissions
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

14. The permittee shall apply for a modification of their current Title V operating permit and an Acid Rain permit within 180 days of operational start-up.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(December 22, 2008)

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, 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 document 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." However, an exceedance report that must be submitted within ten days of the exceedance under Section II (Reporting Of Deviations From Permit Terms) or Section XIV (Emergencies) may be submitted without a certification, if an appropriate certification is provided within ten days thereafter, together with any corrected or supplemental information required concerning the exceedance.

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1) and OAC 252:100-9-3.1(c)]

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 (PM_{10}). 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, 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; and a statement that the facility will continue to comply with all applicable requirements. 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:

(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).

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

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(18) 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:

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

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:
   (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. [OAC 252:100-25]

(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:

(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. [40 CFR 82, Subpart A]

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:

(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. [40 CFR 82, Subpart F]

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]

Associated Electric Cooperative, Inc.
Attn: Mr. Todd Tolbert
Environmental Specialist
2814 S. Golden, P.O. Box 754
Springfield, MO 65801-0754

Re: Permit Number 2007-115-C (M-1) (PSD)
Chouteau Power Plant
Location: Mid America Industrial Park, Mayes County

Dear Mr. Tolbert:

Enclosed is the construction permit authorizing installation of the referenced facility. Please note that this permit is issued subject to the 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 on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or 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, please contact me at eric.milligan@deq.state.ok.us or (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2007-115-C (M-1) PSD

Associated Electric Cooperative, Inc.,

having complied with the requirements of the law, is hereby granted permission to construct/modify/operate the Chouteau Power Plant located in Section 10, T20N, R19E, Mayes County, Oklahoma, subject to the Standard Conditions dated December 22, 2008, and Specific Conditions, both of which are attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division

1-23-09

Date