OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **August 8, 2007**

TO:	Phillip Fielder, P.E., Permits & Engineering Group Manager, Air Quality Division
THROUGH:	Grover Campbell, P.E., Existing Source Permits Section
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	David Schutz, P.E., New Source Permits Section
SUBJECT:	Evaluation of Permit Application No. **2003-403-C (M-1)(PSD)** Public Service Company of Oklahoma (PSO) Southwestern Power Station Washita, Caddo County Sec. 10 – T7N – R11W Directions: From Anadarko, 7 Miles West on SH-9, North 2 Miles, East 0.5 Mile, North 2 Miles Latitude: 35.093ºN, Longitude -98.347º

SECTION I. INTRODUCTION

Public Service Company of Oklahoma (PSO) has requested a modified construction permit for installation of two 1,078 MMBTUH gas-fired turbines in peaking unit service (89 MW each) at their Southwestern Power Station, an electric generating station (SIC Code 4911). The facility is currently operating as authorized by Permit No. No. 2003-403-TVR, issued October 24, 2006.

This permit will have the following changes from Permit No. 2003-403-C (PSD):

- Include the allowances of 40 CFR Part 75.19 for "Low Mass Emitters" (i.e., units with NOx emissions less than 100 TPY and SO_2 emissions less than 25 TPY), specifically, for different emissions monitoring than annual RATA testing in Specific Conditions No. 3.c, 3.d, 4.b, and 8.

- Allow explicitly for using Method 3A in performance testing as required by Specific Condition No. 7. This allowance is already implicit but the application requests that it be made explicit.

- A detailed statement of monitoring requirements currently in Specific Condition No. 8 will be replaced by a more generic statement requiring following the monitoring requirements of 40 CFR Part 75.

- The application requested that the permit be modified to state that "excess emissions that occur during periods of startup, shutdown, or upset conditions should also be exempt from being considered a violation of the applicable limits if the owner or operator complies with the reporting requirements of Subchapter 9 as currently stipulated near the end of this paragraph. The permit, per EPA guidance, already defines what is an acceptable emission during start-up and shutdown, therefore, no change will be made for that part of the request. However, "upset" conditions will be added provided that the upset results from unforeseeable circumstances or circumstances beyond the control of the operator (e.g., lightning strikes on equipment).

- In Specific Condition No. 1.e.v, the applicant requests that "ppmv" be changed to "ppmdv."

- The definition of "start-up" in Specific Condition No. 1.f will be changed from "Startup begins when fuel is supplied to the Gas Turbine" to "Startup for each gas turbine begins when fuel is supplied to the Gas Turbine and combustion is initiated." This change will be made since there is a reasonable expectation that the operator would cease to supply fuel to a turbine if combustion does not initiate.

- The application requests that a seasonal variation in maximum power output (due to ambient temperature differences between summer and winter) be accounted for in the testing requirements. Such an allowance would be in conflict with EPA's "Clean Air Act National Stack Testing Guidance" issued September 30, 2005, and cannot be granted.

- The application requested that Specific Condition No. 7.c state explicitly that stack testing reports be submitted *to the Air Quality Division.*

This permit keeps the full PSD review from the initial construction permit. Project emissions will exceed the PSD Significant Emission Rate (SER) for NO_x, CO and PM_{10}. Therefore, the project is subject to Prevention of Significant Deterioration (PSD) review. The PSD regulations require Best Available Control Technology (BACT) and air quality analyses for each pollutant for which the project is significant.

SECTION II. PROJECT DESCRIPTION

PSO proposes to construct and operate two natural gas-fired combustion turbine electric generating peaking units at the existing Southwestern Power Station. The power block will consist of two GE7EA simple cycle combustion turbine generators (CTGs). Each of the turbines have a peak heat input of approximately 1,078 MMBTUH and an average heat input of approximately 930 MMBTUH. The combustion turbines will fire pipeline-quality natural gas only and are equipped with General Electric's 9/42 Dry low-NO_x (DLN) combustor technology. The proposed new units will have a combined nominal electrical generating capacity of 178 MW.

SECTION III. FACILITY DESCRIPTION

The existing facility produces power using four Babcock and Wilcox pressure-fired steam generators. The total combined steam output from the steam generators is sufficient to generate 500 MW-Gross. The steam is produced by these boilers to drive turbine-generators. Boilers are primarily run on natural gas with No. 2 fuel oil as an alternate fuel, along with small periodic quantities of "on-spec" used oil. Pipeline quality natural gas has been the primary fuel for the boilers since 1995. All four boilers are capable of operating on a continuous basis, but only the #3 boiler is actually operated continuously due to business demand. The other generators, #1N, #1S, and #2 are peaking units, which operate only when it is economically feasible, such as during peak demand. However, the estimated potential emissions listed in the emissions table are based on continuous operation of all four boilers. Also on site are one 2,700-hp diesel-fired emergency generator and seven storage tanks: two 2,100,000-gallon fuel oil tanks, one 84,000-gallon diesel fuel tank, one 16,800-gallon natural gas condensate tank, and three 3,000-gallon lube oil tanks.

SECTION IV. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in the following outline. The new turbines are in EUG 5.

EUG 5 New Combustion Turbines

EU ID#	Point ID#	EU Name, Model	MMBTUH	MW Gross	Serial No.	Installed Date
4	4	GE7EA Combustion Turbine	1,078	89	Not yet available	2007
5	5	GE7EA Combustion Turbine	1,078	89	Not yet available	2007

Both turbines were manufactured in 2002.

EUG 1 Steam Generators

EU ID#	Point ID#	EU Name, Model	MMBTUH	MW Gross	Serial No.	Const. Date
1N	1N	Babcock/Wilcox, S-1853	482**	42	17210	Jan. 1952*
1S	1S	Babcock/Wilcox, S-9747	482**	42	17209	Jan. 1952*
2	2	Babcock/Wilcox, S-9742	940**	84	17438	Feb. 1954*
3	3	Babcock/Wilcox, RB-426	3,290**	332	BW21718	May 1967*

*Date is actual start-up date, not construction start date due to the lack of records available.
**Actual full load used by system operations.

EUG 2 VOL Storage Tanks

EU ID#	Point ID#	Contents	Capacity		Construction Date
			Barrels	Gallons	
TANK1	T-1	Fuel Oil	50,000	2,100,000	1952
TANK2	T-2	Fuel Oil	50,000	2,100,000	1954
TANK3	T-3	Diesel Fuel	2,000	84,000	1954
TANK4	T-4	Condensate	400	16,800	1980*
TANK5	T-5	Lube Oil	71.5	3,000	1954
TANK6	T-6	Lube Oil	71.5	3,000	1966
TANK7	T-7	Lube Oil	71.5	3,000	1966

*This tank is owned and operated by the natural gas supplier, Enogex, Inc.

EUG 3 Emergency Generator

EU ID#	Point ID#	EU Name/Model	hp	Serial No.	Const. Date
EG1	EG1	**General Motors/MP-36**	2,700	63074	April 1962*

*This unit was moved to Southwestern Power Station in 1966.

EUG 4 Fugitive Emissions

Fugitive emissions from this facility are expected to be negligible.

SECTION V. EMISSIONS

Air emissions from the new facility have been calculated using the following methods and factors:

A. <u>Criteria Pollutants – Existing Units</u>

The estimated potential criteria pollutants emissions from boilers are based on the emission factors in AP-42 (7/98), Tables 1.4-1 and 1.4-2, Section 1.4, "Natural Gas Combustion" when gas is burned. The emission factors from AP-42 (9/98), Tables 1.3-1, 1.3-2, and 1.3-3, Section 1.3, "Fuel Oil Combustion" are used when the No. 2 fuel oil (average heating value of 140 MBTU/gal and 0.7 wt % sulfur) is burned.

Table 1 Emission Factors for Boilers (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
Natural Gas	0.2800	0.0840	0.0006	0.0055	0.0076
No. 2 Fuel Oil	0.1714	0.0357	0.7100	0.0054	0.0143

The criteria pollutants emissions from the emergency generator are based on the emission factors in AP-42 (10/96), Tables 3.4-2 and 3.4-5, Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines."

Table 2 Emission Factors for Emergency Generator (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
No. 2 Fuel Oil	3.100	0.081	0.707	0.100	0.0573

The estimated potential emissions for the facility are based on the 8,760 hours/year continuous operation for the boilers, and 500 hours/year for the emergency generator. The selection of 500 hours/year is based on the EPA memo (September 6, 1995), entitled "Calculating Potential to Emit for Emergency Generators" which states that 500 hours is an appropriate default for estimating emissions from these sources.

Table 3 presents the facility-wide estimated potential emissions from natural gas combustion and Table 4 presents the facility-wide estimated potential emissions from No. 2 fuel oil combustion.

Table 3 Facility-Wide Existing Potential Emissions from Natural Gas Combustion

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 1N	134.96	591.12	40.49	177.34	0.29	1.27	2.65	11.61	3.66	16.04
Unit 1S	134.96	591.12	40.49	177.34	0.29	1.27	2.65	11.61	3.66	16.04
Unit 2	263.20	1152.82	78.96	345.84	0.56	2.47	5.17	22.64	7.14	31.29
Unit 3	921.20	4034.86	276.36	1210.46	1.97	8.65	18.10	79.26	25.00	109.52
Unit EG1	21.26	5.31	0.56	0.14	4.85	1.21	0.69	0.17	0.39	0.10
TOTALS	**1475.58**	**6375.24**	**436.85**	**1911.12**	**7.97**	**14.86**	**29.25**	**125.29**	**39.87**	**173.00**

Table 4 Facility-Wide Existing Potential Emissions from No. 2 Fuel Oil Combustion

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 1N	82.61	361.85	17.21	75.37	378.37	1657.26	2.60	11.40	6.89	30.19
Unit 1S	82.61	361.85	17.21	75.37	378.37	1657.26	2.60	11.40	6.89	30.19
Unit 2	161.12	705.69	33.56	146.98	737.90	3232.00	5.08	22.23	13.44	58.88
Unit 3	563.91	2469.91	117.45	514.44	2582.65	11312.01	17.77	77.82	47.05	206.07
Unit EG1	21.26	5.31	0.56	0.14	4.85	1.21	0.69	0.17	0.39	0.10
TOTALS	**911.51**	**3904.62**	**185.98**	**812.30**	**4082.14**	**17859.74**	**28.73**	**123.02**	**74.67**	**325.42**

B. Criteria Pollutants – New Turbines

Criteria pollutant emissions from the combustion turbines are estimated based on GE vendor-supplied emissions data and BACT limits for NOx, CO and PM_{10}. Estimated emissions summarized in the table below are based upon this peaking operation profile at a nominal 2,000 hours per year per unit.

In order to allow for flexibility in operations, PSO proposes to limit the annual fuel usage in the two combustion turbines combined to 4,228 MMscf/yr rather than set fuel usage or hours of operation limits on each turbine individually. This will allow PSO to operate each combustion turbine based on demand for power since one unit or several units may not operate at full capacity. In addition, this will allow PSO to operate one combustion turbine at the facility if the other turbine is unavailable due to malfunction or maintenance issues.

Table 5 Emission Factors for New Turbines

Pollutant	Units	Emission Factor
NO_X	ppmvd @ 15% O_2	9
CO	ppmvd @ 15% O_2	25
VOC	ppmvd @ 15% O_2	1.4
PM_{10}	lb/hr	10
SO_2	lb/MMBTU	0.012
H_2SO_4	% of SO_2	10%

Sulfuric acid mist emissions are based on the applicant's assumption that 10% of SO_2 will be converted to SO_3 and 100% of SO_3 will be converted to H_2SO_4.

Table 6 Potential Emissions from New Combustion Turbines

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Unit 4	35.00	42.29	59.00	71.30	15.00	0.75	2.00	2.00	10.00	10.00
Unit 5	35.00	42.29	59.00	71.30	15.00	0.75	2.00	2.00	10.00	10.00
TOTALS	**70.00**	**84.59**	**118.00**	**142.59**	**30.00**	**1.51**	**4.00**	**4.00**	**20.00**	**20.00**

The applicant expects a large amount of additional emissions resulting from start-ups and shutdowns.

<u>Peaking Operations</u>

Due to their operation as peaking units, these turbines can be expected to experience a regular cycle of startup and shutdown events during which NO_x and CO emission rates are higher than at normal baseload levels. These elevated levels of emissions are accounted for in the pollutant estimates described below. Weekly emission calculations are based on an average of one cold start day per week and three warm start days per week.

PSO is requesting an emissions limit for both turbines combined as opposed to individual emissions limits. By incorporating elevated emission rates during startup and shutdown, higher than during normal operations, the emissions listed above represent the most conservative estimate for the annual emission totals.

Table 7 Estimated Daily Peaking Operation

Cold Start Day	Hours of Operation	NO_x[1]		CO[2]	
		lb/hr	**lb/event**	**lb/hr**	**lb/event**
Normal Operation	9.82	35.00	343.70	59.00	579.38
Cold Start	2	186.06	372.12	313.64	627.28
Shutdown	1	20.29	20.29	34.20	34.20
Downtime	11.18	-	-	-	-
Total (per day)	**24**	**-**	**736.11**	**-**	**1,240.86**

Warm Start Day	Hours of Operation	NO_x[1]		CO[2]	
		lb/hr	lb/event	lb/hr	lb/event
Normal Operation	9.82	35.00	343.70	59.00	579.38
Warm Start	2	56.81	113.62	95.77	191.54
Shutdown	1	20.29	20.29	34.20	34.20
Downtime	11.18	-	-	-	-
Total (per day)	**24**	**-**	**477.61**	**-**	**805.12**

1) Normal operation NOx emission factor based on 9 ppm. Emissions during startup/shutdown based upon CEMS data from operation of a similar-sized GE turbine.
2) Normal operation CO emission factor based on 25 ppm. Emissions during startup/shutdown based upon CEMS data from operation of a similar-sized GE turbine.

Table 8 Estimated Weekly Peaking Emissions

Cold Start	Hours/ Day	Days/ Week	Hours/ Week	NO_x			CO		
				lb/hr	lbs/ week	tons/ week	lb/hr	lbs/ week	tons/ week
Normal Operation	9.82	1	9.82	35.00	343.70	0.17	59.00	579.38	0.29
Cold Start	2	1	2	186.06	372.12	0.19	313.64	627.28	0.31
Shutdown	1	1	1	20.29	20.29	0.01	34.20	34.20	0.02
Downtime	11.18	1	11.18	-	-	-	-	-	-
Subtotal	24			-		0.37	-		0.62
Warm Start				**lb/hr**	**lbs/ week**	**tons/ week**	**lb/hr**	**lbs/ week**	**tons/ week**
Normal Operation	9.82	3	29.46	35.00	1031.1	0.52	59.00	1738.14	0.87
Warm Start	2	3	6	56.81	340.86	0.17	95.77	574.62	0.29
Shutdown	1	3	3	20.29	60.87	0.03	34.20	102.6	0.05
Downtime	11.18	3	33.54	-	-	-	-	-	-
Subtotal	24			-	-	0.72	-	-	1.21
Total				**-**	**-**	**1.08**	**-**	**-**	**1.83**

Table 9 Estimated Annual Peaking Emissions

	Hours/ Week	Weeks/ Year	Hours/ Year	NO_x		CO	
				lb/hr	TPY	lb/hr	TPY
Normal Operation	39.28	39	1,532	35.00	26.81	59.00	45.19
Cold Start	2	39	78	186.06	7.26	313.64	12.23
Warm Start	6	39	234	56.81	6.65	95.77	11.20
Shutdown	4	39	156	20.29	1.58	34.20	2.67
Downtime	44.72	39	-	-	-	-	-
Total			**2,000**		**42.29**		**71.30**

Hazardous Air Pollutants (HAPs) – New and Existing Units

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the existing boilers are based on AP-42, Section 1.3 (7/98) for liquid gas fuel and Section 1.4 (9/98) for gas fuel. HAP emissions from the emergency generator are based on AP-42, Section 3.4 (10/96) but are considered negligible compared to the larger units.

Table 10 Existing Facility HAPs When Burning Liquid Fuel

Total Capacity MMBTUH	Fuel Heating Value BTU/Gal	Fuel Usage Mgal/hr	Fuel Usage Mgal/yr	HAP	Emission Factor lb/Mgal	Emissions	
						lb/hr	TPY
5194	140,000	37.1	324,996	Anthracene	1.22E-06	0.001	0.001
				Benz-a-anthracene	4.01E-06	0.001	0.001
				Benzene	0.000214	0.008	0.035
				Dibenzo(a,h)anthracene	1.67E-06	0.001	0.001
				Ethyl benzene	0.0000636	0.002	0.010
				Formaldehyde	0.033	1.224	5.362
				Naphthalene	0.00113	0.042	0.184
				PCDD	3E-09	0.001	0.001
				Phenanthrene	0.0000105	0.001	0.002
				Toluene	0.0062	0.230	1.007
				Antimony	0.00525	0.195	0.853
				Arsenic	0.00132	0.049	0.214
				Beryllium	0.0000278	0.001	0.005
				Cadmium	0.000398	0.015	0.065
				Chromium	0.000845	0.031	0.137
				Cobalt	0.00602	0.223	0.978
				HCl	0.347	12.874	56.387
				HF	0.0373	1.384	6.061
				Lead	0.00151	0.056	0.245
				Manganese	0.003	0.111	0.487
				Mercury	0.000113	0.004	0.018
				Nickel	0.0845	3.135	13.731
				Selenium	0.000683	0.025	0.111
				Vanadium	0.0318	1.180	5.167

HCl and nickel emissions are above major source thresholds.

Table 11 Existing Facility HAPs When Burning Gas Fuel

Unit Capacity MMBTUH	Fuel Heating Value BTU/SCF	Fuel Usage MMSCFH	Fuel Usage MMSCFY	HAP	Emission Factor lb/MMSCF	Emissions lb/hr	Emissions TPY
5,194	1,020	5.09	44,607	7,12-Dimethylbenz(a) anthracene	0.000016	0.001	0.000
				Anthracene	0.0000024	0.001	0.001
				Benz-a-anthracene	0.0000018	0.001	0.001
				Benzene	0.0021	0.011	0.047
				Dibenzo(a,h)anthracene	0.0000012	0.001	0.001
				Dichlorobenzene	0.0012	0.006	0.027
				Formaldehyde	0.075	0.382	1.673
				Hexane	1.8	9.166	40.147
				Naphthalene	0.00061	0.003	0.014
				Phenanthrene	0.000017	0.001	0.001
				Toluene	0.0034	0.017	0.076
				Arsenic	0.0002	0.001	0.004
				Beryllium	0.000012	0.001	0.001
				Cadmium	0.0011	0.006	0.025
				Chromium	0.0014	0.007	0.031
				Cobalt	0.000084	0.001	0.002
				Manganese	0.00038	0.002	0.008
				Mercury	0.00026	0.001	0.006
				Nickel	0.0021	0.011	0.047
				Selenium	0.000024	0.001	0.001
				Vanadium	0.0023	0.012	0.051

Hexane emissions are above major source thresholds.

Table 12 New Turbines HAPs When Burning Gas Fuel

Unit Capacity MMBTUH	Fuel Heating Value BTU/SCF	Fuel Usage MMSCFH per Turbine	Total Annual Fuel Usage MMSCFY	HAP	Emission Factor lb/MMBTU	Combined Emissions lb/hr	Combined Emissions TPY
1,078	1,020	2,114	4,228	1,3-Butadiene	0.00000043	0.001	0.001
				Acetaldehyde	0.000040	0.085	0.085
				Acrolein	0.0000064	0.014	0.014
				Benzene	0.000012	0.025	0.025
				Ethylbenzene	0.000032	0.068	0.068
				Formaldehyde	0.00071	1.501	1.501
				Naphthalene	0.0000013	0.003	0.003
				PAH	0.0000022	0.005	0.005
				Propylene oxide	0.000029	0.061	0.061
				Toluene	0.00013	0.275	0.275
				Xylene	0.000064	0.135	0.135

SECTION VI. PSD REVIEW

The project is subject to PSD because the added potential emissions of NOx, CO, and PM_{10} are greater than the PSD levels of significance for a modification at an existing major source.

Table 13 Emissions Increases Compared to PSD Levels of Significance

Pollutant	Emissions, TPY	PSD Levels of Significance, TPY	PSD Review Required?
NO_X	84.59	40	Yes
CO	142.59	100	Yes
VOC	4.00	40	No
SO_2	30.00	40	No
PM/PM_{10}	20.00	25/15	Yes
H_2SO_4	0.23	7	No

Full PSD review is required for NOx, CO, and PM_{10}. Full PSD review of emissions consists of the following:

1. Determination of best available control technology (BACT).
2. Evaluation of existing air quality.
3. Evaluation of PSD increment consumption.
4. Analysis of compliance with National Ambient Air Quality Standards (NAAQS).
5. Pre- and post-construction ambient monitoring.
6. Evaluation of source-related impacts on growth, soils, vegetation, visibility.
7. Evaluation of Class I area impact.

The two combustion turbines are subject to NSPS, Subpart GG. Numerous Oklahoma Air Pollution Control rules affect the new turbines, including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities were evaluated for all pollutant-specific rules, regulations and guidelines.

A. Best Available Control Technology (BACT)

The pollutants subject to review under the PSD regulations, and for which a BACT analysis is required, include nitrogen oxides (NO_X), carbon monoxide (CO), 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.

1. Identify all control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by effectiveness.
4. Evaluate most effective controls and document results.
5. Select BACT.

The emission units for which a BACT analysis is required are the combustion turbines. Economic as well as energy and environmental impacts are considered in a BACT analysis. 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. PSO identified these technologies and emissions data 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 following is a list of control technologies, which were identified for controlling emissions from gas turbines and their effective emission reduction levels.

Table 14 BACT Options

Pollutant	Technology	Potential Control Efficiency (%)
NOx	Catalytic Combustion (XONON™)	~95
	Selective Catalytic Reduction (SCR)	50 to 95
	Dry Low NOx Combustors (DLN)	40 to 60
	Selective Non-Catalytic Reduction (SNCR)	40 to 60
	Water / Steam Injection	30 to 50
	Good Combustion Practices	Base Case
CO	Catalytic Oxidation	60 to 80
	Good Combustion Practices	Base Case
PM / PM_{10}	Good Combustion Practices	10 to 30
	Clean Burning Fuels	Base Case

NO_X BACT Review

Nitrogen oxides (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 employ techniques 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 controlling 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. This project proposes the use of Dry-Low NO_X (DLN) combustion, so the less effective controls will not be analyzed.

SCONOX™

SCONOX™, is an emerging catalytic and absorption technology that has shown some promise for turbine applications. Recently, the manufacturer of the SCONOX™ system has announced that it will no longer offer this control technology.

Catalytic (Flameless) Combustion (XONON™)

While several companies are 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.

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 catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configuration as proposed in this application.

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. Keeping the exhaust gas temperature within this range is important. If it 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. Turbine exhaust gas is generally in excess of 1,000 °F. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (e.g., zeolite) which can operate at temperatures up to 1,100 °F are an option. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of about 80 to 95 percent.

The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. The ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

Dry Low-NOx (Lean-Premix) Technology

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. Lean-premix combustors can achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

To achieve low NO_X emission levels, the mixture of fuel and air introduced into the combustor (e.g., air/fuel ratio) must be maintained near the lean flammability limit of the mixture. Lean-premix combustors are designed to maintain this air/fuel ratio at rated load. 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, lean-premix combustors switch to diffusion combustion mode at reduced load conditions. This switch to diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled.

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. However, the more the gas turbine inlet temperature increases, the more NO_X that is produced. 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. Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions of less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control).

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. Nonuniform 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.

Water is a better heat sink than steam; therefore more steam is required to reach a particular level of NO_X emission. However, newer gas turbines usually apply steam injection. Steam injection is generally a better alternative since it does not increase the heat rate as much as water, carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe, and maintenance is reduced.

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$™

SNCR is based on the principle that ammonia or urea reacts with NO_X in the flue gas to form N_2 and H_2O. In practice, the technology has been applied in boilers by injecting ammonia into the high temperature (e.g., 1,300 ºF to 2,000 ºF) region of the exhaust stream. Incorrect location of injection points, insufficient residence times and miscalibration of injection rates may result in excess emissions of ammonia (ammonia slip), a toxic air pollutant. When successfully applied SNCR has shown reduction in NO_x emissions from boilers of 35 to 60 percent.

Thermal DeNO$_X$ is a high temperature selective non-catalytic reduction (SNCR) of NO_X using ammonia as the reducing agent. Thermal DeNO$_X$ requires the exhaust temperature to be above 1,800 ºF.

b) Technical Feasibility of The Control Techniques

XONON™

At the time this construction permit application was submitted there were no facilities using XONON™ technology. There is currently one field installation of the XONON™ technology at a municipal power company, Silicon Valley Power, in Santa Clara, California, being used to perform engineering studies of the technology. NO_X emissions are well below 2.5 ppm on the 1.5 MW Kawasaki M1A-13A gas turbine. Catalytica Combustion Systems (manufacturer of XONON™) has a collaborative commercialization agreement with General

Electric Power Systems, committing to the development of XONON™. In conjunction with General Electric Power systems, the XONON™ system has been specified to be used with the GE 7FA turbines to be used at the proposed 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California. However, because the NO_X emissions limitations of 2.5 ppm have not been demonstrated in practice by a commercial facility, this technology is not considered commercially available at this time.

Selective Catalytic Reduction (SCR)

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 2.5 ppmvd for standard combustion turbines 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. The units will 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 10 ppmvd ammonia slip at 15 percent oxygen.

Lean-Premix Technology

Lean-premix technology is the most widely applied pre-combustion control technology in natural gas turbine applications. It has been demonstrated to achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

Steam/Water Injection

Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control). Water/steam injection was not reviewed because it results in NO_X emissions that are comparable to or 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.

Table 15 NO_X BACT Determinations

RBLC ID	STATE	PROCESS DESCRIPTION	CAPACITY	CONTROL TECHNOLOGY	EMISSION LIMIT
MS-0074	MS	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE	1143.3 MMBTU/H	DLN BURNER WITH INLET GAS COOLING.	9 PPM VD @ 15% O2
OH-0291	OH	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ NATURAL GAS	85 MW	DLN BURNERS	143 LB/H
FL-0261	FL	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	50 MW	WATER INJECTION SYSTEM, SCR	5 PPMVD @15% O2
MN-0053	MN	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1663 MMBTU/H	DLN COMBUSTORS OPERATING IN LEAN PREMIX MODE.	25 PPMVD @ 15% 02
MN-0052	MN	TURBINE, SIMPLE CYCLE, NATURAL GAS	109 MW	DLN, GOOD COMBUSTION PRACTICE	9 PPM @ 15% O2
WA-0312	WA	TURBINES, SIMPLE CYCLE, (2)	108 MW	SCR	5 PPMVD
GA-0107	GA	TURBINE, SIMPLE CYCLE, NATURAL GAS, (6)	108 MW	DLN COMBUSTORS	12 PPM @ 15% O2
KY-0093	KY	TURBINE, SIMPLE CYCLE, NATURAL GAS (6)	160 MW	DLN COMBUSTORS	12 PPM @ 15% O2
MS-0057	MS	TURBINE, SIMPLE CYCLE (3)	1109.3 MMBTU/H	DLN BURNERS	9 PPM @ 15% O2
FL-0244	FL	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	DLN COMBUSTORS	9 PPMVD @ 15% O2
FL-0245	FL	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	DLN COMBUSTORS	9 PPMVD @ 15% O2
IN-0111	IN	TURBINE, SIMPLE CYCLE, NATURAL GAS (8)	80 MW	DLN COMBUSTORS	15 PPMVD @ 15% O2
VA-0282	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1624 MMBTU/H	DLN COMBUSTOR	10.5 PPMVD @ 15% O2
VA-0282	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	901 MMBTU/H	DLN COMBUSTORS	10.5 PPMVD @ 15% O2
VA-0263	VA	TURBINE, SIMPLE CYCLE, (1), NATURAL GAS	1624 MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	10.5 PPMVD @ 15% O2

RBLC ID	STATE	PROCESS DESCRIPTION	CAPACITY	CONTROL TECHNOLOGY	EMISSION LIMIT
VA-0263	VA	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	901 MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	10.5 PPMVD @ 15% O2
VA-0266	VA	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1624 MMBTU/H	DLN BURNERS.	9 PPMVD @ 15% O2
VA-0280	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1624 MMBTU/H	DLN COMBUSTORS WHEN FIRING NATURAL GAS, WATER INJECTION WHEN FIRING FUEL OIL.	10.5 PPMVD
IA-0063	IA	SIMPLE CYCLE TURBINE, NATURAL GAS	80 MW	DLN (NATURAL GAS), WATER INJECTION (FUEL OIL)	0.037 LB/MMBTU
IA-0064	IA	TURBINE, SIMPLE CYCLE	495 MMBTU/H	DLN BURNERS	0.06 LB/MMBTU
MS-0079	MS	TURBINES, SIMPLE CYCLE, NATURAL GAS (4)	959.8 MMBTUH	LOW NOX BURNERS	46.7 LB/H
VA-0265	VA	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1862 MMBTU/H	DLN COMBUSTOR AND A CONTINUOUS EMISSIONS MONITORING SYSTEM.	107 LB/H
VA-0281	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	182.6 MW	DLN COMBUSTORS	107 LB/H
CA-1095	CA	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	48.7 MW	SCR SYSTEM (HIGH TEMP SCR CATALYST)	3.5 PPMVD @ 15% O2
VA-0279	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	82 MW	DLN COMBUSTOR TECHNOLOGY EMPLOYING LEAN PREMIX COMBUSTION CONTROLS	30.6 LB/H
VA-0269	VA	COMBUSTION TURBINES, SIMPLE CYCLE, (4)	82 MW	DLN COMBUSTOR AND CONTINUOUS EMISSION MONITORING SYSTEM.	30.6 LB/H

RBLC ID	STATE	PROCESS DESCRIPTION	CAPACITY	CONTROL TECHNOLOGY	EMISSION LIMIT
CA-1098	CA	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	49.9 MW	SCR SYSTEM AND OXIDATION CATALYST	2.5 PPMVD @ 15% O2
VA-0262	VA	TURBINE, SIMPLE CYCLE, (4)	84 MW	LEAN PRE-MIX LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES. SCR SYSTEM AND A CONTINUOUS EMISSION MONITORING DEVICE.	9 PPMVD @ 15% O2
IL-0086	IL	COMBUSTION TURBINES, SIMPLE CYCLE, 8 EACH	1000.5 MMBTU/H	ADVANCED LOW NOX COMBUSTORS	9 PPMDV @ 15% O2
OH-0274	OH	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW	WATER INJECTION	113 LB/H
OH-0274	OH	TURBINE, SIMPLE CYCLE, NATURAL GAS, UNIT B003	80 MW	WATER INJECTION AND DLN COMBUSTORS	62 LB/H
PA-0205	PA	TURBINE, SIMPLE CYCLE, (8)	84 MW	LOW NOX BURNERS	349 T/YR
VA-0258	VA	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1731 MMBTU/H	LOW NOX BURNER AND CONTINUOUS EMISSION MONITOR	9 PPMVD @ 15% O2
NM-0048	NM	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW	DLN BURNER AND GOOD COMBUSTION PRACTICES	9 PPMV DRY @15% O2
OH-0262	OH	COMPRESSOR TURBINES (2), SIMPLE CYCLE	122 MMBTU/H	DLN BURNERS NATURAL GAS ONLY FUEL	17.1 LB/H
IN-0114	IN	TURBINES, SIMPLE CYCLE, NATURAL GAS, (4)	1490.5 MMBTU/H	DLN COMBUSTORS, GOOD COMBUSTION PRACTICES, CLEAN FUEL -- NATURAL GAS	9 PPMVD @ 15% O2
MI-0345	MI	TURBINE, SIMPLE-CYCLE, NATURAL GAS, (3)	170 MW	DLN BURNERS. CEM FOR NOX. REQUIRED TESTING PER NSPS-GG, 60-180 DAYS	9 PPMVD @ 15% O2

RBLC ID	STATE	PROCESS DESCRIPTION	CAPACITY	CONTROL TECHNOLOGY	EMISSION LIMIT
OH-0253	OH	COMBUSTION TURBINES (2), SIMPLE CYCLE	1115 MMBTU/H	WATER INJECTION	113 LB/H
OH-0253	OH	COMBUSTION TURBINE (1), SIMPLE CYCLE	1115 MMBTU/H	WATER INJECTION AND DRY LOW NOX COMBUSTORS	62 LB/H
FL-0232	FL	TURBINE, SIMPLE CYCLE, NATURAL GAS	1591 MMBTU/H	WATER INJECTION	25 PPMVD
IA-0058	IA	COMBUSTION TURBINES -SIMPLE CYCLE	350 MW		0.09 LB/MMBTU
*LA-0157	LA	SIMPLE CYCLE GAS TURBINE, EPN 2-1		USE OF NATURAL GAS AS FUEL AND GOOD OPERATING PRACTICES. LOW NOX BURNERS AND/OR SCR	58 LB/H
TX-0388	TX	GAS TURBINES, SIMPLE CYCLE (4)	48 MW (EACH)	DLN BURNERS	5 PPM @ 15% O2
NC-0084	NC	TURBINES, SIMPLE CYCLE, NATURAL GAS, (6)	155 MW	DLN COMBUSTORS	10.5 PPMVD
NC-0086	NC	TURBINE, SIMPLE CYCLE, NATURAL GAS (2)	1702 MMBTU/H	DLN COMBUSTORS AND SCR	9 PPMVD

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$™

The only known commercial applications of Thermal DeNO$_X$™ 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. This option has not been demonstrated on CTs. Thus, this control technology was not considered technically feasible and was precluded from further consideration in this facility's BACT analysis.

c) Control Technology Effectiveness and Impacts

The most effective control technology for NO$_X$ is SCR, which is routinely required for units which operate year-round but not for peaking units whose operations are limited to much lower levels. A review of the RBLC indicates that the established emission limit is comparable to what has been approved for other large combustion turbines in recent years.

The BACT proposal was reviewed using the EPA RACT/BACT/LAER Clearinghouse at the EPA web site. The reference cited several other gas-fired peaking turbines for which BACT was reviewed in the U.S. recently. The turbines ranged from 902 MMBTUH to 1,701 MMBTUH. The smallest of the turbines had a NOx limitation of 25 ppm, while those larger turbines had limitations in the range of 5-10.5 ppm. Thus, for turbines of this size, the BACT limitation of 9 ppm proposed is consistent with other facilities nation-wide.

In addition, the average cost per ton of NOx controlled would be excessive using SCR. The applicant has estimated control costs at $65,849 per ton NOx removed.

Dry low-NOx is acceptable as BACT for these turbines.

CO BACT Review

Carbon monoxide is formed as a result of incomplete combustion of fuel. 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 also tend to result in high NO$_X$ emissions. Conversely, 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.

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. Alternative CO 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.

a) Identification of Control Techniques

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of CO control, which may be achieved for natural gas fired gas turbines. Emission levels and control technologies have been identified and ranked as follows:

- 2 to 10 ppm: CO oxidation catalyst;
- 10 to 25 ppm: Combustion control for natural gas firing.

These levels of control are evaluated in terms of best available control technology in the following sections.

The most stringent CO control level available for the gas turbines would be achieved with the use of an oxidation catalyst system, which can remove approximately 80 percent of CO. A CO oxidation catalyst is concluded to represent the top control technology for CO for natural gas-fired turbines.

b) Technical Feasibility of The Control Techniques

As 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 of CO to CO_2 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. 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}.

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 turbine exhaust (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 1.5 to 3.0 inches of water (Engelhard 1999). Pressure losses in this range correspond roughly to a 0.15 to 0.30 percent loss in power output and fuel efficiency (General Electric 1997).

Catalyst systems are subject to loss of activity over time. 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.

c) Control Technology Effectiveness and Impacts

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 (10% 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 $PM_{2.5}$. 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.

Capital and annual costs associated with installation of an oxidation catalyst system were calculated using vendor quotes. The average cost effectiveness of installing a catalyst system to control emissions of CO was estimated at $23,723 per ton of CO removed.

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.

Table 16 CO BACT Determinations

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
MS-0074	MS	12/10/2004	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE	1143.3 MMBTU/H		20 PPM VD @ 15% O2
OH-0291	OH	11/17/2004	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ NG	85 MW		83 LB/H
FL-0261	FL	10/26/2004	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	50 MW	OXIDATION CATALYST	6 PPMDV @ 15% O2
MN-0053	MN	7/15/2004	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1663 MMBTU/H	GOOD COMBUSTION PRACTICES.	10 PPMVD @ 15% 02
MN-0052	MN	9/10/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS	109 MW	GOOD COMBUSTION PRACTICES - OPTIMIZED OPERATION OF GAS TURBINE	25 PPM @ 15% O2
GA-0107	GA	6/9/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (6)	108 MW	GOOD COMBUSTION PRACTICE	0.019LB/MMBTU
KY-0093	KY	6/6/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (6)	160 MW	GOOD COMBUSTION PRACTICE	9PPM @ 15% O2
MS-0057	MS	5/29/2003	TURBINE, SIMPLE CYCLE (3)	1109.3 MMBTU/H	GOOD OPERATING PRACTICES	25 PPMVD @ 15% O2
FL-0244	FL	4/16/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	GOOD COMBUSTION DESIGN AND PRACTICES	8PPMVD @ 15% O2
FL-0245	FL	4/15/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	GOOD COMBUSTION DESIGN AND PRACTICES	7.4 PPMVD @ 15% O2
IN-0111	IN	3/13/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (8)	80 MW	GOOD COMBUSTION PRACTICE	25 PPMVD @ 15% O2
VA-0282	VA	3/11/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1624 MMBTU/H	GOOD COMBUSTION PRACTICES	9 PPMVD
VA-0282	VA	3/11/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	901 MMBTU/H	GOOD OPERATING PRACTICES	25 PPMVD

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
VA-0263	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (1), NATURAL GAS	1624 MMBTU/H	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	9 PPMVD @ 15% O2
VA-0263	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	901 MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	25 PPMVD @ 15% O2
VA-0266	VA	2/14/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1624 MMBTU/H	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUEL.	9 PPMVD
VA-0280	VA	2/14/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1624 MMBTU/H	GOOD COMBUSTION PRACTICE	9 PPMVD
MS-0079	MS	1/30/2003	TURBINES, SIMPLE CYCLE, NATURAL GAS (4)	959.8 MMBTUH	GOOD COMBUSTION PRACTICES	58LB/H
VA-0265	VA	1/10/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1862 MMBTU/H	CLEAN BURNING FUELS AND GOOD COMBUSTION PRACTICES.	3.7LB/H
VA-0281	VA	1/10/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	182.6 MW	CLEAN FUEL, GOOD COMBUSTION CONTROL	81 LB/H
CA-1095	CA	1/10/2003	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	48.7 MW	OXIDATION CATALYST	6 PPMVD @ 15% O2
VA-0279	VA	1/8/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	82 MW	GOOD COMBUSTION PRACTICE	51.7 LB/H
VA-0269	VA	1/8/2003	COMBUSTION TURBINES, SIMPLE CYCLE, (4)	82 MW	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	51.7 LB/H
CA-1098	CA	12/15/2002	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	49.9 MW	SCR SYSTEM AND OXIDATION CATALYST	6 PPMVD @ 15% O2
VA-0262	VA	12/6/2002	TURBINE, SIMPLE CYCLE, (4)	84 MW	GOOD COMBUSTION PRACTICES.	51 PPMVD @ 15% O2
IL-0086	IL	11/27/2002	COMBUSTION TURBINES, SIMPLE CYCLE, 8 EACH	1000.5 MMBTU/H	GOOD COMBUSTION PRACTICES	25 PPMVD @ 15% O2

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
OH-0274	OH	10/1/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW		1700 LB/H
OH-0274	OH	10/1/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, UNIT B003	80 MW		301 LB/H
PA-0205	PA	9/17/2002	TURBINE, SIMPLE CYCLE, (8)	84 MW	GOOD COMBUSTION PRACTICE	71 T/YR
VA-0258	VA	8/29/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1731 MMBTU/H	GOOD COMBUSTION PRACTICE	8 PPMVD @ 15% O2
NM-0048	NM	8/19/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW	GOOD COMBUSTION PRACTICES, NG AS PRIMARY FUEL	203 PPM @ 15% O2
OH-0262	OH	8/15/2002	COMPRESSOR TURBINES (2), SIMPLE CYCLE	122 MMBTU/H	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	22.6 LB/H
IN-0114	IN	7/24/2002	TURBINES, SIMPLE CYCLE, NATURAL GAS, (4)	1490.5 MMBTU/H	GOOD COMBUSTION PRACTICES, CLEAN FUEL -- NATURAL GAS.	9 PPMVD @ 15% O2
MI-0345	MI	7/1/2002	TURBINE, SIMPLE-CYCLE, NATURAL GAS, (3)	170 MW	GOOD COMBUSTION	7.9 PPMVD @ 15% O2
OH-0253	OH	6/4/2002	COMBUSTION TURBINES (2), SIMPLE CYCLE	1115 MMBTU/H		1700 LB/H
OH-0253	OH	6/4/2002	COMBUSTION TURBINE (1), SIMPLE CYCLE	1115 MMBTU/H		301 LB/H
FL-0232	FL	4/25/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS	1591 MMBTU/H	GOOD COMBUSTION	10 PPM
IA-0058	IA	4/10/2002	COMBUSTION TURBINES - SIMPLE CYCLE	350 MW		0.023 LB/MMBTU
*LA-0157	LA	3/8/2002	SIMPLE CYCLE GAS TURBINE, EPN 2-1		GOOD OPERATING PRACTICES, USE OF NATURAL GAS AS FUEL. BACT FOR NOX, LOW NOX BURNERS AND/OR SCR, IS ALSO BACT FOR CO.	28 LB/H
TX-0388	TX	2/12/2002	GAS TURBINES, SIMPLE CYCLE (4)	48 MW (EACH)	LIMITED TO 2,750 HOURS PER YEAR. SEE NOTE	43 PPM @ 15% O2
NC-0084	NC	1/25/2002	TURBINES, SIMPLE CYCLE, NATURAL GAS, (6)	155 MW	COMBUSTION CONTROL	9 PPMVD

Table 17 PM_{10} BACT Determinations

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
MS-0072	MS	12/10/2004	GENERAL ELECTRIC COMBUSTION TURBINES			15.8 LB/H
MS-0072	MS	12/10/2004	GENERAL ELECTRIC COMBUSTION TURBINES			15.8 LB/H
MS-0072	MS	12/10/2004	GENERAL ELECTRIC COMBUSTION TURBINES			15.8 LB/H
MS-0074	MS	12/10/2004	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE	1143.3 MMBTU/H		10 LB/H
FL-0261	FL	10/26/2004	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	50 MW	CLEAN FUELS	2.45 LB/H
MN-0053	MN	7/15/2004	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1663 MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.01 LB/MMBTU
NE-0022	NE	6/22/2004	GAS-FIRED COMBUSTION TURBINE	1 MMSCF/H	LOW ASH CONTENT NG	10 LB/H
NE-0021	NE	6/22/2004	2-173 MW COMBUSTION TURBINES	173 MW		0.12 LB/MMBTU
WA-0312	WA	7/18/2003	TURBINES, SIMPLE CYCLE, (2)	108 MW	GOOD COMBUSTION PRACTICE	0.01 GR/DSCF
GA-0107	GA	6/9/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (6)	108 MW	LOW SULFUR FUEL	0.023 LB/MMBTU
KY-0093	KY	6/6/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (6)	160 MW	GOOD COMBUSTION PRACTICE	19 LB/H
MS-0057	MS	5/29/2003	TURBINE, SIMPLE CYCLE (3)	1109.3 MMBTU/H	LOW ASH FUEL (NATURAL GAS) AND GOOD COMBUSTION PRACTICES.	10 LB/H
FL-0244	FL	4/16/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	CLEAN FUEL - PIPELINE NATURAL GAS	
FL-0245	FL	4/15/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	CLEAN FUEL	
GA-0098	GA	3/24/2003	COMBUSTION TURBINE, (2)	171.7 MW	NATURAL GAS	0.011 LB/MMBTU

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
IN-0111	IN	3/13/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (8)	80 MW	CLEAN FUEL -- NATURAL GAS	
VA-0263	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (1), NATURAL GAS	1624 MMBTU/H	GOOD COMBUSTION PRACTICES.	18 LB/H
VA-0263	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	901 MMBTU/H	GOOD COMBUSTION PRACTICES.	10 LB/H
VA-0282	VA	3/11/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1624 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	18 LB/H
VA-0282	VA	3/11/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	901 MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION	10 LB/H
VA-0266	VA	2/14/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1624 MMBTU/H	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUEL.	18 LB/H
VA-0280	VA	2/14/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1624 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	18 LB/H
IA-0064	IA	1/31/2003	TURBINE, SIMPLE CYCLE	495 MMBTU/H	GCP, NATURAL GAS ONLY	0.02 LB/MMBTU
MS-0079	MS	1/30/2003	TURBINES, SIMPLE CYCLE, NATURAL GAS (4)	959.8 MMBTUH	USE OF CLEAN FUEL: NATURAL GAS.	7 LB/H
MS-0079	MS	1/30/2003	TURBINES, SIMPLE CYCLE, NATURAL GAS (4)	959.8 MMBTUH	USE OF CLEAN FUEL: NATURAL GAS	7 LB/H
CA-1095	CA	1/10/2003	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	48.7 MW		0.01 G/SCF
VA-0265	VA	1/10/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	1862 MMBTU/H	CLEAN BURNING FUELS AND GOOD COMBUSTION PRACTICES.	27 LB/H
VA-0281	VA	1/10/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	182.6 MW	CLEAN FUEL, GOOD COMBUSTION CONTROL	27 LB/H
VA-0269	VA	1/8/2003	COMBUSTION TURBINES, SIMPLE CYCLE, (4)	82 MW	GOOD COMBUSTION PRACTICES.	10 LB/H
VA-0279	VA	1/8/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	82 MW	GOOD COMBUSTION, CLEAN FUEL	10 LB/H

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
CA-1098	CA	12/15/2002	GAS TURBINE: SIMPLE CYCLE >= 2 MW AND < 50 MW	49.9 MW		3 LB/H
VA-0262	VA	12/6/2002	TURBINE, SIMPLE CYCLE, (4)	84 MW	GOOD COMBUSTION PRACTICES. DRIFT ELIMINATORS.	10 LB/H
IL-0086	IL	11/27/2002	COMBUSTION TURBINES, SIMPLE CYCLE, 8 EACH	1000.5 MMBTU/H	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS FUEL.	0.014 LB/MMBTU
OH-0274	OH	10/1/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW		8 LB/H
OH-0274	OH	10/1/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, UNIT B003	80 MW		8 LB/H
VA-0258	VA	8/29/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	1731 MMBTU/H		13.8 LB/H
TX-0390	TX	8/21/2002	GAS TURBINES NO1 & NO2 (2)	87 MW		5 LB/H
NM-0048	NM	8/19/2002	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	80 MW	GOOD COMBUSTION PRACTICES, NATURAL GAS AS PRIMARY FUEL.	10 PPH
OH-0262	OH	8/15/2002	COMPRESSOR TURBINES (2), SIMPLE CYCLE	122 MMBTU/H	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	3.2 LB/H
IN-0114	IN	7/24/2002	TURBINES, SIMPLE CYCLE, NATURAL GAS, (4)	1490.5 MMBTU/H		0.012 LB/MMBTU
IA-0060	IA	7/23/2002	COMBUSTION TURBINE	33.77 BILLION CF/YR		0.0051 LB/MMBTU
IA-0060	IA	7/23/2002	COMBUSTION TURBINE	33.77 BILLION CF/YR		0.0051 LB/MMBTU
IA-0060	IA	7/23/2002	COMBUSTION TURBINE	33.77 BILLION CF/YR		0.0098 LB/MMBTU
IA-0060	IA	7/23/2002	COMBUSTION TURBINE	33.77 BILLION CF/YR		0.0098 LB/MMBTU

RBLC ID	STATE	PERMIT DATE	PROCESS NAME	CAPACITY	CONTROL DESCRIPTION	EMISSION LIMIT
MI-0345	MI	7/1/2002	TURBINE, SIMPLE-CYCLE, NATURAL GAS, (3)	170 MW	NATURAL GAS ONLY	18.4 LB/H
OK-0070	OK	6/13/2002	SW COMBUSTION TURBINE	1872 MMBTU/H	LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0092 LB/MMBTU
OH-0253	OH	6/4/2002	COMBUSTION TURBINES (2), SIMPLE CYCLE	1115 MMBTU/H		8 LB/H
OH-0253	OH	6/4/2002	COMBUSTION TURBINE (1), SIMPLE CYCLE	1115 MMBTU/H		8 LB/H
OK-0067	OK	5/29/2002	COMBUSTION TURBINES	308 MW	GOOD COMBUSTION PRACTICES	134 T/YR
SC-0064	SC	5/23/2002	TURBINE, GAS FIRED, (3) EACH	170 MW	CLEAN FUELS (NATURAL GAS), GOOD COMBUSTION PRACTICES	24 LB/H
OK-0072	OK	5/6/2002	COMBUSTION TURBINES	1832 MMBTU/H	USE OF NATURAL GAS	0.012 LB/MMBTU
IA-0058	IA	4/10/2002	COMBUSTION TURBINES - SIMPLE CYCLE	350 MW		0.0094 LB/MMBTU
TX-0351	TX	3/11/2002	(2) GE 7241FA GAS TURBINES (TEMP STACK), S-1&2	1910 MMBTU/H	NONE INDICATED	18 LB/H
TX-0351	TX	3/11/2002	(2) GE7121EA GAS TURBINES, S-3&4	1079 MMBTU/H	NONE INDICATED	14 LB/H
*LA-0157	LA	3/8/2002	SIMPLE CYCLE GAS TURBINE, EPN 2-1		LOW NOX BURNERS AND/OR SCR, GOOD OPERATING PRACTICES AND USE OF NATURAL GAS AS FUEL.	18 LB/H
TX-0388	TX	2/12/2002	GAS TURBINES, SIMPLE CYCLE (4)	48 MW	GOOD COMBUSTION PRACTICE	4.5 LB/H
NC-0084	NC	1/25/2002	TURBINES, SIMPLE CYCLE, NATURAL GAS, (6)	155 MW	COMBUSTION CONTROL	9 LB/H

d) Summary

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) emissions and is not considered cost effective. A review of EPA's RBLC database indicates that other combustion turbines that utilize natural gas have been issued permits with BACT-based CO emissions in the range of 3 to 60 ppm (based on full load operation). Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the emission limits are believed to be representative of the top level of emission control. Using combustion control has been determined to represent BACT for the turbines. The resulting emission levels results in modeled impacts that are less than the 1-hour and 8-hour CO NAAQS. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative. Good combustion controls applied to the combustion turbines can achieve carbon monoxide emission levels of 25 ppmvd corrected to 15% oxygen when operating in the normal "premix" mode.

PM_{10} BACT Review

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 to be less than 1 micron, so all emissions are 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. The maximum estimated PM_{10} emission rate is 0.0093 lbs/MMBTU (HHV) from the turbines. Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the 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.

Startup / Shutdown BACT Review

The turbine manufacturer would not guarantee in writing a time frame for start-up and shutdown. Emissions during start-up and shutdown were calculated assuming a 2-hour period but with a reasonable expectation that full pre-mixed operation can occur in a fraction of that time.

The BACT analysis for start-up and shutdown continued from the normal operation BACT analysis, determining a cost per ton of pollutant removed. Catalytic oxidation was used for CO emissions and SCR for NOx emissions. Annualized control costs were calculated at $2,041,743 to remove 9 TPY NOx, or $240,376 per ton. Annualized control costs for CO were calculated $1,623,234 to remove 20 TPY CO, or $81,162 per ton. These costs are excessive.

In the absence of manufacturer guarantees, the permit will define "start-up" as being the first two hours of operation. BACT for these periods is acceptable as no add-on controls.

Table 19: Startup / Shutdown BACT Limits

Event	Maximum Duration (hr)	NO_x Emissions (lbs)	CO Emissions (lbs)
Startup (cold)	2	372	627
Startup (warm)	2	114	192
Shutdown	1	21	35

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 or modification has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels 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 to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the modeling significance levels, a radius of impact is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area. Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility did not exceed the PSD modeling significance levels.

Modeling Methodology

Modeling was conducted using AERMOD PRIME to determine if a significant impact area for each pollutant occurred. A Cartesian receptor grid was used in the modeling analysis. A grid extending to 10 kilometers with variable spacing was used. From the plant site out to one kilometer, a 100-meter spacing was used, from one kilometer to five kilometers, a 500-meter spacing was used, and from five kilometers to 10 kilometers, a 1000-meter spacing was used. Receptors were placed at 50-meter intervals along the site fence line.

The meteorological data were pre-processed in AERMET using land-use/micromet parameters, i.e., Albedo, Bowen ratio, and surface roughness provided by the Oklahoma DEQ. A summary of these parameters is provided below.

Table 20 AERMET Land-Use Parameters

Property	Winter Dec-Jan-Feb	Spring Mar-Apr-May	Summer Jun-Jul-Aug	Autumn Sep-Oct-Nov
Albedo Values	0.60	0.14	0.20	0.18
Bowen Ratio Average Values	1.40	0.30	0.50	0.70
Surface Roughness Values	0.05	0.10	0.20	0.10

A downwash analysis was completed using EPA's BPIP model. The site is located in a rural area and the only buildings that could potentially affect the emissions from the facility are the turbine structures. The downwash analysis was completed to insure that wake effects from the structures at the site will not cause the emissions from the facility to result in concentrations that exceed the PSD Class II increments or NAAQS.

United States Geological Survey Digital Elevation Models (DEM) were obtained and terrain elevations in the vicinity of the site were taken from the DEM and entered into the model input files. Terrain elevations were selected as the highest of each four surrounding points.

Surface meteorological data from the OKC airport were used in conjunction with upper air data from Oklahoma City and Norman to produce the meteorological input files for the modeling analysis. In 1989, the National Weather Service's upper air site was moved from Oklahoma City to Norman, resulting in a three week loss of data. As such, the 1989 data was not used in this analysis. Upper air data from Oklahoma City were used for 1986 through 1988, and upper air data from Norman were used for 1990 and 1991. The anemometer height at this time was 6.09 meters.

The turbines will normally be operated in the 75-100% load range except during startup, shutdown, and malfunctions. Emissions from the turbines in this load range are highest at 100% load, therefore, emissions of NOx, CO, and PM_{10} were modeled at 100% load. The stack parameters following and the emission rates on the following page were used in the modeling analysis.

Table 21 Stack Parameters

Source	Height feet	Diameter feet	Temperature degrees F	Flowrate ACFM
Unit 4	92	22.0	947	2,693,620
Unit 5	92	22.0	947	2,693,620

Modeling Results

The modeling results shown are the highest resulting concentrations and show that the proposed turbines will not result in a significant impact on ambient air quality in the vicinity of the site. Although new PM_{10} modeling protocol requires comparing the fourth-high 24-hour estimate to the standard, PSO has shown compliance with the highest 24-hour modeled concentration.

Table 22 Significance Level Comparisons

Pollutant	Averaging Period	Year	Maximum Concentrations ($\mu g/m^3$)	Significance Levels ($\mu g/m^3$)
NO_2	Annual	1986	0.38	1
CO	8-hour	1988	289.07	500
	1-hour	1986	134.51	2000
PM_{10}	Annual	1986	0.10	1
	24-hour	1986	4.54	5

The modeling indicates added facility emissions will result in ambient concentrations below the significance levels in which an area of impact is defined. Therefore, no additional modeling for increment or NAAQS compliance is required.

C. Ambient Monitoring

The predicted maximum ground-level concentrations of pollutants by air dispersion models have demonstrated that the ambient impacts of the facility are below the monitoring exemption levels. No pre-construction nor post-construction ambient monitoring will be required. The maximum ambient impacts of the source and the monitoring exemption levels are shown following.

Table 23 Comparison of Modeled Impacts to Monitoring Exemption Levels

Pollutant	Monitoring Exemption Levels		Ambient Impacts	
	$\mu g/m^3$	Averaging Time	$\mu g/m^3$	Averaging Time
NO_2	14	annual	0.38	annual
CO	575	8-hour	134.51	8-hour
PM_{10}	10	24-hour	4.54	24-hour
VOC / Ozone	100 TPY Added VOC		4.0 TPY Added VOC	

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

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. Few employees will be needed. The fuel for the plant will arrive by pipeline rather than by vehicle.

Growth Impacts

Since the plant will require a small permanent staff, no significant air quality impact is expected. Modification of the plant would not result in an increase in the number of permanent residents. No significant industrial or commercial secondary growth will occur as a result of the project since the number of permanent employees needed is small.

Soils and Vegetation

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. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted NO_2 pollutant concentrations from the power plant are expected to be below the secondary NAAQS. No significant adverse impact on soil and vegetation due to NO_2 emissions is anticipated due to the addition of the two proposed peaking units.

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. This protection extends to agricultural soil. The maximum predicted CO pollutant concentrations from the proposed turbines are expected to be below the NAAQS. As discussed in the dispersion modeling report, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed project.

PM can be carried over long distances by the wind and settle on the ground. 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 use of natural gas fuel (only) in the proposed peaking units ensures minimal PM emissions from the project.

Visibility Impairment

The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It was approved that a minimum distance of 1 km could be screened using visibility-screening procedures. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of discharges, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

E. Class I Area Impact Analysis

Federal Class I Areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. These areas were established as part of the PSD regulations included in the 1977 Clean Air Act Amendments. Federal Class I Areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. Class I Modeling Significance Levels (MSLs) for certain criteria pollutants have been proposed by the EPA and Federal Land Managers (FLMs) in the Federal Register (July 23, 1996, 40 CFR 51). The lower values proposed by the FLMs are summarized in the table below.

Table 24 Class I MSLs (Recommended)

Pollutant	Modeling Significance Level ($\mu g/m^3$)		
	Annual	24-hr	3-hr
SO_2	0.03	0.07	0.48
PM_{10}	0.08	0.27	-
NO_2	0.03	-	-

In addition to these MSLs, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) has published a Phase I report that defines certain Air Quality Related Values (AQRVs) that must be addressed in a Class I air quality analysis. AQRV indicators typically identified by FLMs include visibility impairment and acidic deposition. Although the FLMs are also concerned about ozone affects on vegetation, there are currently no models available to predict the impact of emissions from a single source on ozone concentrations in Class I Areas. Therefore, the FLMs analyze the results of the visibility and deposition analysis to gauge the impact of NO_X emissions from a facility on Class I Areas. If the results of the visibility and deposition analysis are acceptable, it is a good indicator that NO_X emissions from the facility will not adversely impact ozone concentrations in the Class I Areas

The Wichita Mountains National Wildlife Refuge, managed by the Fish and Wildlife Service, is located approximately 45 km away from the Southwestern Station and is the only Federal Class I area within 300 km. As described below, a significance analysis and evaluation of visibility was conducted for the Wichita Mountains. Acidic deposition is not specifically addressed beyond demonstrating that SO_2 and sulfuric acid mist (SAM) emissions from the proposed project are minimal and do not trigger PSD SERs.

As with the Class II analysis, the Significance Analysis determines whether the facility will forego further analysis for a particular pollutant and defines the ROI within which a Full Impact Analysis, if necessary, would be required. Similarly, the U.S. EPA does not require that additional analyses (i.e. the Full Impact Analysis) be performed for a particular pollutant when emissions of that pollutant from the proposed emissions units do not result in concentrations above the proposed Class I MSLs.

As described in the permit application, both NO_2 and CO exceed their PSD SERs. CO, however, is not evaluated because there are not separate Class I MSL or PSD Increment standards, nor is it considered a precursor to visibility impairment. As a result, the Class I significance analysis for the Wichita Mountains focused on NO_2.

An AQRV is generally defined as a resource, as identified by the FLM or one or more federal areas, that may be adversely affected by a change in air quality. In addition to visibility and acidic deposition, other AQRVs include effects to flora, fauna, or cultural/archeological/ paleontological artifacts). In their Phase I Report, FLAG has established certain levels of concern for different types of visibility impairments. For single sources located within 50 km of a view (as is the case with this project), FLAG has suggested the following parameters for screening analyses: an absolute value of contrast (i.e., the difference between the plume and the background) of C = 0.05 and a color difference index (ΔE) of 2. These levels of concern are considered thresholds for closer scrutiny by the FLM.

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 minimal 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. For the initial analysis, Level 1 parameters were used for this project.

Table 25 Level 1 VISCREEN Parameters

Parameter	Value	Units	Source
Background visual range of region	40	Km	U.S. EPA Office of Air Quality Planning and Standards. Workbook for Plume Visual Impact Screening and Analysis (Revised). Research Triangle Park, NC. EPA-454/R-92-023. October 1992.
Distance to closest Class I boundary	44.5	Km	Based upon source-receptor coordinates as provided by National Park Service, http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm
Distance to furthest Class I boundary	57.30	Km	
Source-observer distance	44.5	Km	Set equal to minimum Class I boundary distance
Background Ozone	0.04	ppm	
Atmospheric Stability	6		Worst-case stability
Wind speed	1	m/s	Worst-case wind speed

Default worst case meteorological conditions were utilized as recommended by the VISCREEN model. In addition, VISCREEN requires input data on several pollutants that contribute to visibility impairment, including NO_x, NO_2, PM_{10}, soot and sulfate (SO_4-^{2}). There are no emissions of primary NO_2, soot, or sulfate from this project.

A summary of results from the VISCREEN model is presented in the table below. As seen in this table, the screening thresholds established by FLAG in its Phase I report (Dec. 2000, pg. 26) are not exceeded. As a result, additional review is not necessary.

Table 26 VISCREEN Analysis Results

Distance to Nearest Class I boundary (km)	Distance to Furthest Class I Boundary (km)	Maximum E (Screening Limit 2.0)	Contrast (Screening Threshold –0.05)
44.5	57.3	0.233	-0.001

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are duplicated below. Records are available to confirm the insignificance of the activities. Appropriate recordkeeping of activities indicated below with "*" is specified in the Specific Conditions.

1. * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or distillate fuel oil which are used exclusively for emergency power generation not to exceed 500 hours/year. The backup diesel generator is used for emergency power generation and is not expected to operate more than 500 hours/year.

2. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTU/hr heat input (commercial natural gas). None identified but may be used in the future.

3. * Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period.

4. * Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature.

5. * Bulk gasoline or other fuel distribution with a daily average throughput less than 2,175 gallons per day, including dispensing, averaged over a 30-day period.

6. Gasoline and aircraft fuel handling activities, equipment, and storage tanks except those subject to New Source Performance Standards and standards in OAC 252:100-37-15, 252:100-39-30, 252:100-39-41, and 252:100-39-48.

7. * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. None identified but may be used in the future.

8. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1).

9. Cold degreasing operations utilizing solvents that are denser than air.

10. * Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes.

11. Torch cutting and welding of under 200,000 tons of steel fabricated per year.

12. Emissions from landfills and landfarms unless otherwise regulated by an applicable state or federal regulation.

13. Surface coating operations which do not exceed a combined total of more than 60 gallons per month of coatings, thinners, and clean-up solvents at any one emission unit.

14. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

15. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas.

16. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. None identified but may be used in the future.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (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 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they existed on September 1, 2005, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, Subpart BBBB, Subpart DDDD, Subpart HHHH and Appendix G. NSPS requirements are addressed in the "Federal Regulations" 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]
Part 5 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.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which 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 operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.60 lbs/MMBTU for all equipment at this facility with a heat input rating of 10 Million BTU per hour (MMBTUH) or less. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the following equipment is subject to the requirements of this subchapter. Emission factors shown in Section III (Emissions) above indicate that all units are in compliance.

Equipment	Maximum Design Heat Input, (MMBTUH)	Appendix C Emission Limit, (lbs/MMBTU)	Potential Emission Rate, (lbs/MMBTU)
Unit 4	1,078	0.18	0.0093
Unit 5	1,078	0.18	0.0093

This subchapter also limits emissions of PM from industrial processes. Per AP-42 factors, there are no significant PM emissions from any other industrial activities at this facility.

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 will assure compliance with this rule by ensuring "complete combustion" and utilizing pipeline-quality natural gas as the primary fuel.

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 fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. The permit will require the turbines to be fired with pipeline-grade natural gas with SO_2 emissions limits equivalent to 0.012 lb/MMBTU.
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. The boilers pre-dated this rule and the Backup Diesel Generator is below 50 MMBTUH heat input and are, therefore, not subject to this rule.

Units	**MMBTUH**	**lb/hr**	**lb/MMBTU**
Turbines	1,078	35.00	0.047

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]
<u>Part 3</u> requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The fuel oil tank (T-1) and diesel fuel tank (T-2) are exempt based on vapor pressures below the 1.5 psia level.
<u>Part 3</u> requires VOC loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading and is not subject to this requirement.
<u>Part 5</u> limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment. No coating operation is located at this facility.
<u>Part 7</u> requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement.
<u>Part 7</u> requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.
<u>Part 7</u> also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. All of the pumps and compressors at this facility are subject to these requirements.

OAC 252:100-41 (Hazardous Air Pollutants) [Applicable]
<u>Part 3</u> addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on September 1, 2005, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY,

ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS and TTTTT are hereby adopted by reference as they exist on September 1, 2005. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.
Part 5 was a **state-only** requirement governing sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42, effective June 15, 2006.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superceded by this subchapter. 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 IX. 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 VI.

NSPS, 40 CFR Part 60 [Subparts A and GG are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction of any affected facility, the facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility will be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the facility. The facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ.

Subpart 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 proposed 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 each turbine is 9 ppmdv at 15% O_2 and is therefore more stringent than the Subpart GG standards. Performance testing by Reference Method 20 is 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 KKKK affects stationary gas turbines that commenced construction, modification, or reconstruction after February 18, 2005. Although these turbines are being relocated to the Southwestern facility, they were originally manufactured pre-2003. As a result, Subpart KKKK does not apply.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: asbestos, benzene, beryllium, coke oven emissions, radionuclides, or vinyl chloride except for trace amounts of arsenic, benzene, beryllium, and mercury. 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 [Not 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. The turbines were both built in 2002, therefore, are "existing" gas-fueled turbines. There are no standards in Subpart YYYY for existing units.

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 are not subject to CAM monitoring since the low-NOx combustors are not considered add-on control devices.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable At This Time]
The facility has two 10,000-gallon (~64,218 lbs) anhydrous ammonia storage tanks, which can store above the applicable threshold for anhydrous ammonia (10,000 lbs). If ammonia is 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, 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 has submitted their acid rain permit application.

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).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.
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.

SECTION X. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be Tier I based on the request for a minor modification to a construction permit for a Part 70 source. Minor modifications are considered any modifications that:

1. Do not violate any applicable requirement, or state-only requirements (This modification will not violate any applicable requirements.);
2. Do not involve significant changes to existing monitoring, reporting or recordkeeping requirements in the permit (This modification will require new monitoring, reporting, and recordkeeping requirements for the new equipment but will not change any existing requirements.);
3. Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis (This modification does not require a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis.);

4. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include federally-enforceable emissions caps assumed to avoid classification as a modification under any provision of Title I and alternative emissions limits approved pursuant to regulations promulgated under § 112(i)(5) of the Act (This permit does not establish or change a permit term or condition to avoid applicable requirements.); and
5. Are not modifications under any provision of Title I of the Act. (This modification is not a modification under any provision of Title I of the Act since no emission rate or PSD analysis is affected.)

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

The "proposed" permit was submitted to EPA for a 45-day review period. No comments were received from Region VI.

The "proposed" permit was also available for public review on the Air Quality Section of the DEQ Web Page at *http://www.deq.state.ok.us*. This facility is not located within 50 miles of the Oklahoma border.

Fees Paid
Minor modification of a Part 70 construction permit application fee of $500.

SECTION XI. SUMMARY

The facility has demonstrated the ability to comply with applicable state and federal air pollution control 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 that would prohibit issuance of this modified operating permit. Issuance of the construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Public Service Company of Oklahoma (PSO)
Southwestern Power Station **Permit No. 2003-403-C (M-1)(PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on August 18, 2006, with additional information submitted on September 11, 2006 and June 11, 2007. The Evaluation Memorandum dated August 8, 2007, 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 and standards for each point:
[OAC 252:100-8-6(a)(1)]

EUG 5. Combustion Turbines. Emission limits and standards for Emission Units (EUs) 4 and 5 include but are not limited to the following:

Each of the Two Combustion Turbines are limited to the following:			**The Two Turbines Combined Are Limited to the Following Sums:**
Pollutant	**lb/hr** [1]	**ppmvd**[2]	**TPY** [3]
NO_X	35.00	9	84.59
CO	59.00	25	142.59
VOC	2.00	--	4.00
SO_2	15.00	--	30.00
PM_{10} [4]	10.00	--	20.00
H_2SO_4	0.12	--	0.24

[1] Three-hour rolling average, based on the arithmetic average of three contiguous one-hour operating periods.
[2] All concentrations are corrected to 15% O_2, per turbine.
[3] Twelve-month rolling total.
[4] PM_{10} limits are for filterable plus condensable PM_{10}.

a. The turbines shall only be fired with pipeline-quality natural gas.
[OAC 252:100-31 & 8-34]

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

c. The turbines shall burn no more than a total of 4,228 MMSCFY (combined total, based on an average heating value of 1,020 Btu/CF) of pipeline-grade natural gas per 12-month rolling period. [OAC 252:100-8-5]

d. During start-up, the turbines shall not operate more than 2-hours outside the pre-mix mode. During normal operations, the turbines shall not operate below 60 percent of the rated turbine load. Excess emissions that result from upset conditions, malfunctions or maintenance are exempt from the limits established above if the owner or operator complies with the requirements of OAC 252:100-9-3.1 and OAC 252:100-9-3.3(c) and demonstrates that the conditions of OAC 252:100-9-3.3(a)(1)-(9) or OAC 252:100-9-3.3(b)(1)-(7) apply. For an excess emission to be deemed to result from "upset" conditions, it must result from unforeseeable circumstances or circumstances beyond the control of the operator (e.g., lightning strikes on equipment). [OAC 252:100-9]

e. Each turbine is subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR 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 ppmdv) 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 Subpart GG shall not be required unless the permittee claims an allowance for fuel bound nitrogen.

f. During startups and shutdowns alternate emission limits apply to the combustion turbines. Startup events shall not exceed two hours per turbine. Shutdown events shall not exceed one hour per turbine. Emission limits for NO_x and CO during startups and shutdowns shall be as listed in Specific Condition No. 1.f. The following definitions apply.

Startup: Startup for each gas turbine begins when fuel is supplied to the Gas Turbine and combustion is initiated. Startup ends when the gas turbine reaches DLN mode (as direct by the control system).
Shutdown: Shutdown begins when the turbine exits the DLN mode. Shutdown ends with the termination of fuel flow to the turbine.
Cold Start: A startup beginning more than 24 hours after the same unit shutdown.
Warm Startup: A startup beginning less than 24 hours after the same unit shutdown.
For startup and shutdown operations, the emission limitations for each combustion turbine are listed below:

Event	Maximum Duration (hr)	NO_x Emissions (lbs)	CO Emissions (lbs)
Startup (cold)	2	372	627
Startup (warm)	2	114	192
Shutdown	1	21	35

2. Each new combustion turbine shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

3. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following:

   a. SO_2 actual emissions equal or less than allowances held.
   b. Report quarterly emissions to EPA per 40 CFR Part 75.
   c. Conduct RATA tests per 40 CFR Part 75 or qualify as "low mass emitters" under 40 CFR 75.19; if the latter is followed, representative NOx emissions testing shall be conducted and a QA/QC plan for the monitoring system shall be followed.
   d. Maintain a QA/QC plan for the monitoring system.

4. 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 252:100-43]

   a. Usage of natural gas in each turbine (monthly and 12-month rolling total).
   b. RATA test results or representative test results per 40 CFR Part 75, Appendix E.

5. No later than 180 days after operational start-up of the first turbine, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, an application to incorporate the turbines into the facility's Part 70 operating permit. [OAC 252:100-8-6]

6. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility at this time:
[OAC 252:100-8-6(d)(2)]

   a. 40 CFR Part 60, NSPS except for Subpart GG
   b. 40 CFR Part 61, NESHAP
   c. 40 CFR Part 63, NESHAP
   d. 40 CFR Part 64, Compliance Assurance Monitoring
   e. 40 CFR Part 68, Chemical Accident Prevention Provisions
   f. OAC 252:100-21, PM Emissions from Wood-Waste Burning Equipment
   g. OAC 252:100-19-12, PM Emissions from Directly Fired Fuel-Burning Units and Industrial Processes

7. Within 180 days following commencement of operations of each new turbine, performance testing shall be conducted on each new turbine. [OAC 252:100-43]

   a. Performance testing by the permittee shall use the following test methods specified in 40 CFR 60:

Method 1: Sample and Velocity Traverses for Stationary Sources.
Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4: Determination of Moisture in Stack Gases.
Method 7 or 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources
Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources
Method 18 or 25A: Determination of Volatile Organic Compounds Emissions From Stationary Sources
Method 201/201A: Determination of PM_{10} Emissions
Method 202: Determination of Condensable Particulate Emissions

b. Performance testing shall be conducted while the units are operating within 10% of maximum production rate.

c. A written report documenting results of emissions testing shall be submitted to the Air Quality Division within 60 days of completion of on-site testing.

d. At least 30 days prior to testing, a pre-testing plan shall be submitted to the Air Quality Division.

8. Emissions monitoring shall be performed in compliance with the requirements of 40 CFR Part 75.

9. This permit supersedes Permit No. 2003-403-C (PSD), which is now null and void.

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. 2003-403-C (M-1)(PSD)

Public Service Company of Oklahoma (PSO),

having complied with the requirements of the law, is hereby granted permission to construct two _89-MW peaking generator units at their Southwestern Power Station located in Section 10, T7N, R11W, Caddo County, Oklahoma, subject to standard conditions dated December 6, 2006, and specific conditions, both attached.

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

______________________________ ______________________________

Permits & Engineering Group Manager **Date**
Air Quality Division

Public Service Company of Oklahoma (PSO)
Attn: Mr. Kris Gaus
Senior Environmental Specialist
1201 Elm Street
Dallas, TX 75270

SUBJECT: Permit No. **2003-403-C (M-1)(PSD)**
Southwestern Power Station
Location: Washita, Caddo County

Dear Mr. Gaus:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to the certain standards 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.

If you have any questions, please refer to the permit number above and contact the permit writer at David.Schutz@deq.state.ok.us or at (405) 702-4198.

Sincerely,

David S. Schutz, P.E.
New Source Permits Section
AIR QUALITY DIVISION

Enclosures

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(December 6, 2006)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) 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, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All terms and conditions (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[40 CFR §70.6(b), OAC 252:100-8-1.3 and 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. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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. Oral notifications (fax is also acceptable) shall be made to the AQD central office 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 the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under OAC 252:100-8-6 (a)(3)(C)(iii) shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iii)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. Unless a different retention period or retention conditions are set forth by a specific term 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), 8-6 (c)(1), and 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 as 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. [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 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.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under OAC 252:100-8-6 and OAC 252:100-43 shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. 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 preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. 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. [40 CFR §70.6(a), 40 CFR §51.212(c)(2), 40 CFR § 70.7(d), 40 CFR §70.7(e)(2), OAC 252:100-8-6 (a)(3)(A)(iv), and OAC 252:100-43]

The reporting of total particulate matter emissions as required in Part 70, PSD, OAC 252:100-19, and 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). [US EPA Publication (September 1994). PM_{10} Emission Inventory Requirements - Final Report. Emission Inventory Branch: RTP, N.C.]; [Federal Register: Volume 55, Number 74, 4/17/90, pp.14246-14249. 40 CFR Part 51: Preparation, Adoption, and Submittal of State Implementation Plans; Methods for Measurement of PM_{10} Emissions from Stationary Sources]; [Letter from Thompson G. Pace, EPA OAQPS to Sean Fitzsimmons, Iowa DNR, March 31, 1994 (regarding PM_{10} Condensables)]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

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. 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)(A), (C)(v), and (D)]

B. The 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.

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

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification 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, -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 10 days after such date.

[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, 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 as necessary to remedy deficiencies in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.

C. If “grandfathered” status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.
(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

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):

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

(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.

SECTION XIV. EMERGENCIES

A. Any emergency and/or 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)]

B. 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. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.

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

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

(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;
(4) the permittee submitted timely notice of the emergency to AQD, pursuant to the applicable regulations (i.e., for emergencies that pose an "imminent and substantial danger," within 24 hours of the time when emission limitations were exceeded due to the emergency; 4:30 p.m. the next business day for all other emergency exceedances). *See OAC 252:100-8-6(a)(3)(C)(iii)(I) and (II).* 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; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

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)]

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. [OAC 252:100-8-2]

(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.

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]

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 7 days, or 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 subsection. [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) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) 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]
(3) 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]
(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for 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. [OAC 252:100-25]
(5) 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]
(6) 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]

(7) Volatile Organic Compound (VOC) storage tanks built after December28, 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)]

(8) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances. [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4.

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13.

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B. [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.

(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166.

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158.

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Sources' 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 Oklahoma Administrative Code 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 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 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 CFR § 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 CFR § 70.8(a) and (c).

(5) The DEQ complies with 40 CFR § 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 CFR § 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 CFR § 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]