OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **June 18, 2018**

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

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

THROUGH: Amalia Talty, P.E., Existing Source Permit Section

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2015-1968-C (M-2) PSD**
Western Farmers Electric Cooperative
Anadarko Power Plant (SIC 4911/NAICS 22112)
Facility ID: 1699
NW/4 of Section 14, T7N, R10W, Caddo County
Latitude: 35.08293°N; Longitude: 98.23380°W
Located 1 mile north of SH 62 and 7th Street in Anadarko, Oklahoma

SECTION I. INTRODUCTION

Western Farmers Electric Cooperative (WFEC) has requested a modification of the original prevention of significant deterioration (PSD) construction permit (Permit No. 2000-273-C (PSD)) for the installation of the two natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7 and AN-UNIT8) at the facility which was previously named GENCO Anadarko Power Plant which is now part of the WFEC Anadarko Power Plant. The modification would remove the 0.09 lb NO_X/MMBTU emission limit. Only issues related to the 0.09 lb NO_X/MMBTU emission limit are revised in this permit. This modification will not increase emissions from the facility nor change the BACT determination. The PSD evaluation to include best available control technology (BACT) and air dispersion modeling are incorporated into this permit as they existed in Permit No. 2000-273-C (PSD) which was issued on November 30, 2000. The facility is currently operating as authorized by Permit No. 2015-1968-TVR3, issued February 6, 2018.

Based on information in the original permit application, the 0.09 lb NO_X/MMBTU emission limit established in the original PSD permit is equivalent to the 41 lb/hr and 25 ppmdv NO_2 at 15% O_2 emission limits at a heat input of 457.95 MMBTUH, high heating value (HHV), at 20 °F. WFEC believes that the 0.09 lb NO_X/MMBTU emission limit is overly burdensome and unnecessary for demonstrating compliance with the underlying applicable requirement of OAC 252:100-33 (0.2 lb/MMBTU). The AQD agrees with the assessment and has removed the 0.09 lb NO_X/MMBTU emission limit from the permit.

SECTION II. FACILITY DESCRIPTION

The facility generates wholesale electricity which is transmitted over WFEC's electrical distribution system. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma. The facility currently consists of three (3) natural gas-fired high pressure boilers (AN-UNIT1R, AN-UNIT2R, and AN-UNIT3), three (3) natural gas-fired combined cycle gas turbines (AN-UNIT4, AN-UNIT5, and AN-UNIT6), five (5) natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7, AN-UNIT8, AN-UNIT9, AN-UNIT10 and AN-UNIT11), two (2) diesel-fired engines (ENG-1, and Emerg. Gen.) and other sources which are considered insignificant or trivial. AN-UNIT1R, AN-UNIT2R, and AN-UNIT3 are backup units that only operate when it is feasible, such as during peak demand. This permit only addresses two of the natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7 and AN-UNIT8) and the diesel-fired emergency black start generator (Emerg. Gen.) which were authorized by Permit No. 2000-273-C (PSD).

AN-UNIT7 and AN-UNIT8, are capable of producing 47,000 kW each with quick start capability and will combust approximately 452 MMBTUH of natural gas each. The two (2) turbines are designed as peaking units, with a combined operation of 8,000 hours per year.

There is only one operating scenario for the facility with the turbines fueled with commercial-grade natural gas. Emission units (EUs) are arranged into Emission Unit Groups (EUGs) in the "Equipment" section.

SECTION III. EQUIPMENT

EUG 4 Internal Combustion Engine

EU	Make/Model	hp	Serial #	Const. Date
Emerg. Gen	Kohler/600 ROZD-4	910	0655525	2000

EUG 6 Simple Cycle Combustion Turbines

EU	Manufacturer	MMBTUH[1]	MW	Serial #	Const. Date
AN-UNIT7	General Electric	451.7	47	191264	2001
AN-UNIT8	General Electric	451.7	47	191246	2001

[1] - HHV; Maximum Heat Input @ 59 °F &100% Load.

Stack Parameters

EU	Height (feet)	Diameter (feet)	Flow (ACFM)	Temperature (°F)
AN-UNIT7	45	9.0	538,202	790
AN-UNIT8	45	9.0	538,202	790

SECTION IV. EMISSIONS

AN-UNIT7 & AN-UNIT8

Potential emissions from EU AN-UNIT7 and AN-UNIT8 are based on a 12-month rolling total of the combined operation of both units for 8,000 hours of operation, the maximum rated heat input, and the following emission factors:

	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2
Factor	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[2]
lb/hr	0.0895	0.2675	0.0047	0.0066	0.0034
TPY	0.0882	0.0504	0.0031	0.0066	0.0034

1 - Manufacturer's data;

lb/hr factors based on worst-case: 20 °F @ 100% Load (458 MMBTUH-HHV).

NO_X: 25 ppmvd @ 15% O_2.

CO: 125 ppmvd @ 15%O_2.

VOC: 5 ppmvd @ 15% O_2 ; 20% of HC.

CO and VOC are 2.5 times the manufacturer's data as suggested by the manufacturer.

TPY factors based on average: 59 °F @ 100% Load (452 MMBTUH-HHV):

NO_X: 25 ppmvd @ 15% O_2.

CO: 23 ppmvd @ 15%O_2.

VOC: 1.5 ppmvd @ 15% O_2; 20% of HC.

2 - AP-42 (4/2000), Section 3.1, Table 3.1-2a default value.

Emerg. Gen

Potential emissions from EU Emerg Gen are based on 500 hours of operation per year, the maximum engine rating, and the following emission factors:

	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2
EU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU[2]
Emerg. Gen[1]	1.4363	0.2305	0.0435	0.0777	0.0015

1 - Manufacturer's data based on original standby rating: 765-bhp, 37.7 gallons/hour, and 0.137 MMBTU/gallon.

2 - SO_2 emissions based on AP-42 (10/1996), Section 3.4, Table 3.4-1, and a fuel sulfur content of 15 ppm by weight (Ultra Low Sulfur Diesel).

Permitted Emissions

	NO_X		CO		VOC		PM_{10}		SO_2	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
AN-UNIT7	41.0	159.3	122.5	91.0	2.1	1.2	3.0	12.0	1.6	6.2
AN-UNIT8	41.0		122.5		2.1		3.0		1.6	
Emerg. Gen	7.4	1.9	1.2	0.3	0.2	0.1	0.4	0.1	0.1	0.1
Totals	**89.4**	**161.1**	**246.2**	**91.3**	**4.4**	**1.3**	**6.4**	**12.1**	**3.3**	**6.3**

The turbines and engine have emissions of HAP, the most significant being formaldehyde. Emissions of formaldehyde are based on the following: Turbines - AP-42 (4/00), Section 3.1 for standard operation and Section 3.1 reference data for less than 25% load; and Engine - AP-42

(10/96), Section 3.3. A specific condition limiting emissions of formaldehyde to less than 10 TPY is established.

Formaldehyde Emissions from the Turbines and Engine

		Rating	Factors	Max Emissions		Actuals[c]
Sources	**# Units**	**MMBTUH**	**lb/MMBTU**	**lb/hr**	**TPY**	**TPY**
GE Simple Cycle Turbines[a]	2	452.0	0.00071 (normal)	0.642	1.530	0.90
		106.25	0.0131 (SU/SD)	2.784		
Kohler Engine[b]	1	5.17	0.0012	0.002	0.001	0.00
Totals				**20.357**	**5.059**	**4.55**

[a] - Units are limited to annual operation of 8,000 hours per year combined. SU/SD. Startup operations are based on 200 hours per year combined.

[b] - Unit is limited to 100 hours of operation for testing, the unit may be used for unlimited periods in the event of an emergency.

[c] - Based on 2016 emission inventory data.

SECTION VII. PSD EVALUATION / SCOPE OF REVIEW (From Permit No. 2000-273-C (PSD))

The existing facility is a PSD major source, therefore, modification must be reviewed to determine if any PSD significance level will be exceeded. The following table lists the total emissions from the modification compared to the PSD significance levels. Since NO_X emissions exceed the PSD significance level, full PSD review is required for NO_X. The three year contemporaneous emissions are not listed here since the facility is not netting out, however, these emissions are included and described in the modeling section.

Significance Levels Comparisons (TPY At Maximum Operation)

Pollutant	Emissions	PSD Significance Level	PSD Review Required
NO_X	161.14	40	yes
CO	91.30	100	no
VOC	1.26	40	no
PM_{10}	12.24	15	no
SO_2	1.27	40	no
Lead	0.02	0.6	no
H_2SO_4	0.18	7	no

The project is also subject to NSPS Subpart GG for combustion turbines. Numerous Oklahoma air quality rules affect the new turbines and emergency generator as fuel-burning equipment; rules including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities were evaluated for all pollutant-specific rules, regulations and guidelines. Since HAP emissions are calculated below the 10/25 TPY threshold, no case-by-case MACT review is required.

Full PSD review of emissions consists of the following:

- determination of best available control technology (BACT)
- evaluation of existing air quality and determination of monitoring requirements
- evaluation of PSD increment consumption
- analysis of compliance with National Ambient Air Quality Standards (NAAQS)
- evaluation of source-related impacts on growth, soils, vegetation, visibility
- evaluation of Class I area impacts

SECTION VIII. BACT REVIEW
(From Permit No. 2000-273-C (PSD))

The requirement to conduct a BACT analysis is set forth in the PSD regulations [OAC 252:100-8-30 et seq.]. BACT is generally defined in the PSD regulations as the following:

> *"... the control technology to be applied for a major source or modification is the best that is available as determined by the Executive Director on a case-by-case basis taking into account energy, environmental, costs and economic impacts of alternate control systems."*

The BACT review follows the "top-down" methodology. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented on the following page are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, Draft BACT Guidelines:

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

The EPA has consistently interpreted the statutory and regulatory BACT definition as containing two core requirements that the agency believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies, (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

If the source is subject to a New Source Performance Standard (NSPS), the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate. In other words, the applicable NSPS represents the maximum allowable emission limit from an emission source.

The BACT requirements only apply to the pollutants that are subject to PSD review and the emission units that are newly installed or physically modified. The GENCO peaking units are new emission units with potential NO_X emissions above PSD significance levels and, therefore, subject to BACT review.

a) Control Technology Identification

NO_X reduction can be accomplished by two general methodologies, combustion control methods and post-combustion control techniques. Combustion control techniques incorporate fuel or air staging that affect the stoichiometry and kinetics of NO_X formation or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Post-combustion technologies chemically reduce NO_X to molecular nitrogen (N_2) with or without the use of a catalyst.

Specific NO_x control technologies are identified from the U.S. EPA control technology database search, technical literature, and control equipment vendor information and by using process knowledge and engineering experience. Potentially applicable control options and typical control ranges for NO_X were identified and summarized below.

Control Technology	Typical Emission Levels
SCONOx™	2-5 ppm
XONON flameless combustion	3-5 ppm
Selective catalytic reduction (SCR)	5-9 ppm
Selective non-catalytic reduction (SNCR)	9-25 ppm
Non-selective catalytic reduction (NSCR)	9-25 ppm
Dry low NO_X combustor	9-25 ppm
Water or steam injection	25-42 ppm

A general overview of each of these control technologies is provided in the following paragraphs. Technical feasibility, environmental impacts, and economical feasibility are discussed in the subsequent sections.

b) Control Technology Overview

SCONOx™

SCONOx™ is an emerging technology which offers the promise of reducing combined-cycle NO_X emissions to values in the range of 2 to 3.5 ppm. EPA issued a finding on July 2, 1997, that

SCONOx™ has been demonstrated in practice as LAER at a 23 MW facility in California and those emissions have been demonstrated at 2.5 ppm.

According to literature the system uses an oxidation/absorption/regeneration cycle across a catalyst bed to achieve back end reductions of NO_X. Unlike SCR, the system does not require ammonia as a reagent and involves parallel catalyst beds that are alternately taken off-line for regeneration through means of mechanical dampers.

The SCONOx™ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2. The NO_2 is absorbed into a potassium carbonate catalyst coating as KNO_2 and KNO_3. When a catalyst module begins to become "loaded" with potassium nitrites and nitrates, it is taken off-line and isolated from the flue gas stream with mechanical dampers for regeneration.

Once the module has been isolated from the oxygen rich turbine exhaust, 4 percent hydrogen in an inert carrier gas of nitrogen or steam is introduced. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. It should be noted that four percent is about the lower flammability limit for hydrogen, so it is important that air seals around dampers do not leak. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_2O and N_2 that is emitted from the stack.

Catalytic (Flameless) Combustion

Another emerging technology that is potentially capable of reducing combustion turbine NO_X emissions to 3 to 5 ppm is catalytic combustion. 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™.

According to literature provided by Catalytica, XONON™ combustors have reduced combustion turbine NO_X emissions to as low as 3 ppm in laboratory and pilot tests. Unlike SCONOx™ or selective catalytic reduction (SCR), flameless combustion requires no down-stream clean up device, but rather prevents the formation of thermal NO_x during combustion of the fuel. This technique avoids the need for ammonia injection and avoids system efficiency losses due to catalyst back pressure. The XONON™ technology actually replaces the traditional diffusion or lean pre-mix combustion cans of the combustion turbine.

In a typical combustor, fuel and air are burned at flame temperatures that may approach 2,700°F. NO_X formation rate is exponential with flame temperature above 2,000°F, so thermal NO_X is formed within the combustors. The combustor exhaust is then diluted with cooling air to get the gas temperature below about 2,400°F, which is the upper temperature limit of the metal parts, which make up the power turbine. With the XONON™ system, a fuel/air mix is oxidized across several small catalyst beds to "burn" fuel at less than the flame temperature at which thermal NO_X formation begins. The XONON™ combustor does, however, utilize a partial flame downstream to complete the combustion process (burnout zone) and unavoidable small amounts of NO_X emissions are generated within this zone. Resulting emissions are being guaranteed by Catalytica at 5 ppm for certain applications and have been demonstrated as low as 3 ppm under test conditions. Like all catalysts, the XONON™ combustor catalyst performance can be expected to "age" with time.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post-combustion removal of NO_X from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$
$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \quad (2)$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3)$$
$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \quad (4)$$
$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \quad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate present in the flue gas, such as would be the case for the proposed combustion turbines. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown also to have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Optimum operating temperature for platinum catalyst system is in the range of 400° to 800°F and for the base metal catalyst system is in the range of 550° to 800°F. These catalysts deteriorate quickly when continuously operated at temperatures above this range or under thermal cycling which is commonly experienced by simple cycle peaking turbines. Operation at part load, and during start-up and shutdown yields non-optimum SCR temperature and decreased NO_X conversion efficiency. Since operation at less than design temperatures would neither effectively remove NO_X nor reduce ammonia, both would be emitted from the stack during off design catalyst temperatures. For this reason, automatic controls are used to reduce ammonia feed below set point temperature.

SCR manufacturers have developed zeolite-based catalyst systems that can handle high temperatures in the range of 790-1,100 °F and can withstand thermal load swings associated with peaking turbine installations. Typically, natural gas-fired simple-cycle turbine exhausts range in the higher temperature window of 850-1,000 °F, which is outside the range of most base metal catalysts, but theoretically within the range of operation for hot-SCR zeolite catalysts.

Selective Non-Catalytic Reduction (SNCR)

SNCR is based on the principal that ammonia or urea react 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°F - 2,000°F) 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 hazardous air pollutant (HAP). When successfully applied, however, SNCR has shown reductions in NO_x emissions from boilers of 35 to 60 percent.

Non-Selective Catalytic Reduction (NSCR)

This control technology uses a catalyst, generally a mixture of platinum and rhodium, to promote simultaneous conversion of NO_X, CO, and unburned hydrocarbon. NSCR is also referred to as "three-way conversion". NSCR requires the combustion process to be slightly fuel rich and within a temperature range of 650°F-1500°F. Under this condition, the CO reduces the NO_X to N_2 and CO_2. NSCR can achieve 80-95% NO_x conversion.

Dry Low NO_X Combustor

Although dry low NO_X (DLN) combustors designed by different manufacturers may vary, they all employ the strategies of fuel and air pre-mixing and staged combustion to minimize NO_X formation in combustion turbines. The combustors burn a lean, pre-mixed fuel and air mixture to avoid localized high temperature regions. Other techniques such as variable geometry, fuel staging, or combustion staging, are also incorporated in DLN combustor design. As a result, NO_X emissions are 60-80% lower than conventional combustors.

Water or Steam Injection

Sufficient water or steam can be injected into the flame zone of a turbine combustor to quench the peak flame temperature, thereby reducing the thermal NO_X formation. In general, water or steam injection can control NO_X emissions from conventional combustion turbines to a range of 25-42 ppm. This control technique may reduce turbine thermal efficiency and/or increase CO emissions.

c) Technical Feasibility

This section analyzes the technical feasibility of each of the control options described in the previous section.

SCONOx™

While SCONOx™ is a promising technology, it has yet to be fully demonstrated for commercial operation on a simple cycle combustion turbine. Further, it has not been demonstrated on any unit on a long-term basis.

The catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources gradually accumulate on the surface of the catalyst, eventually masking or poisoning active catalyst sites over time. This is why catalyst performance is known to degrade or "age" over time. All catalysts begin life at their highest level of reactivity, resulting in very low emissions when first installed. Goal Line reports that they have had to take periodic outages to wash the catalyst; apparently SO_2 present in natural gas is sufficient to mask the active catalyst sites. Goal Line proposes to install an SO_2 "guard bed" called SCOSOx™ on future systems, but this component is unproven. As stated previously, catalyst aging is also experienced with conventional SCR catalysts; however, with these systems the operating experience exists to confidently predict catalyst life and catalyst replacement cost is far less than with SCONOx™.

Another area of concern is that the SCONOx™ process is dependent on numerous hot side dampers and gas seals that must cycle every 10 to 15 minutes. While further research and development (R&D) could be done during scale up in an effort to reduce the number of moving parts, the SCONOx™ system requires many mechanical linkages, activators, and damper seals which must operate reliably within a hostile flue gas environment. This, in combination with a lack of long-term demonstration generates concerns about the long-term availability of the system for this project.

XONON™ Catalytic (Flameless) Combustion

XONON™ is currently in development stage and does not represent a commercially available NOx control technology. While XONON™ is being sold as an alternative control technology for certain turbine models, it is currently not offered for the GE LM6000 turbines. At this time XONON™ is not a feasible control technology for the GENCO Site.

Selective Catalytic Reduction (SCR)

Conventional SCR is a proven (technically feasible) method of control for NOx emissions. The U.S. EPA identifies zeolite based SCR applications as most compatible with simple cycle turbines. However, a review of permit applications utilizing zeolite catalyst shows that the nascent technology has operational problems that would limit its technical feasibility:

> The June 1999 permit application for the ManChief facility in Colorado provides a narrative about simple-cycle high-temperature SCR applications which concludes that there are some discrepancies in the literature (Ozone Transport Assessment Group and Institute of Clean Air Companies - ICAC reports) about the instances of successful implementation of the technology for similar applications. This application identified only a single small turbine with SCR at a research facility.
>
> The U.S. EPA ACT reference, "NO_X Emissions From Stationary Combustion turbines" (EPA-453/R-93-007), indicated that zeolite based SCR applications were the most compatible with simple-cycle turbine operations. However, the reference also noted that there was only one SCR installation operating with a zeolite catalyst directly downstream of the turbine which mostly operated at 930 °F. The reference for this statement indicates that the turbine mentioned is the same small turbine mentioned in the ICAC paper.
>
> A permit application (Kendall Power facility in Plano, IL, dated February 1999) indicated that high-temperature SCR applications were fraught with operational problems, "...sustained operation at such high temperatures and widely fluctuating peaking turbine loads will likely result in the excessive wear and premature replacement of the zeolite catalyst."

A review of the RBLC database showed only a handful of projects that have proposed hot-SCR for similar turbine applications. The individual projects were further researched for status of hot-SCR implementation:

> Southern California Gas, Wheeler Ridge, CA - Simple-cycle natural gas-fired DLN equipped turbines each less than 10 MW. Hot-SCR initially installed on two turbines did not function properly. Subsequently, a modified hot-SCR system is being installed and tested.
>
> City of Redding Municipal Utilities, Redding, CA - 3 simple-cycle natural gas-fired GE Frame 5 turbines at 25 MW each. Water injection and hot-SCR installed on turbines does not function properly. The turbine exhaust is 900-950 °F. The facility lowers the NO_X emissions down to 40 ppmv with water injection followed by SCR to try to lower it further down to 9 ppmv - the permit limit. The facility is experiencing recurring plugging problems with the catalyst which is rapidly deteriorating under the severe thermal conditions and also blinding readily. The NO_X control efficiency has dropped significantly and the ammonia slip has risen above the typical 10 ppmv range. The catalyst vendor has been contacted to remedy the reduced performance. The facility is now contemplating conversion to combined-cycle operations.
>
> Puerto Rico Electric Power Authority - 3 ABB 80 MW each simple-cycle #2 oil-fired turbines. Hot-SCR not operating as promised by catalyst manufacturer with high soot buildup on catalyst. Additional ammonia injection has not helped lower NO_x emissions. Major effort underway by catalyst manufacturer to modify the system so that the required emission limits can be met.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically guarantee 3-year lifetimes for very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_X reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which results in ammonia slip. Thus an emissions trade-off between NO_X and ammonia occurs in high NO_X reduction applications.

Finally, an add-on SCR control technology will add 2.5 to 4.5 inches WC backpressure on the turbine. Based on the Industrial Combustion Coordinated Rulemaking (ICCR) combustion work groups 1998 estimates, there is a 0.15% peak power generation capacity penalty per inch of pressure drop. This translates to significant loss of power generation capacity and loss of revenue for the GENCO Site.

The above discussion indicates that hot SCR technology has technical challenges. However, conventional SCR systems are considered as technically feasible control options and are further analyzed as BACT.

<u>Selective Non-Catalytic Reduction (SNCR)</u>

Operating temperature of SNCR must be between 1,300°F to 2,000°F. The combustion turbine exhaust maximum temperature is 915°F. At this or lower temperatures, the chemical reactions in the SNCR process will not occur. It is impractical to heat up the large volume of turbine exhaust gases to the desired SNCR temperature. No SNCR application in combustion turbine NO_X control is found in the EPA RBLC database. Therefore, the SNCR option is eliminated from further evaluation.

<u>Non-Selective Catalytic Reduction (NSCR)</u>

In the NSCR process, hydrocarbon and CO are adsorbed on the catalyst and become strong reducing agents. They can reduce NO_X to N_2. This reaction will take place only when there is no other compounds that are stronger oxidants than NO_X. In combustion turbine exhaust gases, the oxygen level is at about 11% to 15% by volume. With the presence of such a high level of oxygen in the gas stream, CO and hydrocarbon will react with oxygen, rather than NO_X, and NO_X reduction will not be achieved. Therefore, NSCR is not a technically feasible option.

<u>Dry Low NO_X (DLN) Combustor</u>

A DLN combustor is a technically feasible control option. This option has been used in the past and represents the leading edge technology that offers low NO_X emissions and additional operational flexibility at the present time. DLN combustors typically result in NO_X emission levels of 9 to 25 ppmv depending on turbine design (aero-derivative or frame) and size.

Water or Steam Injection

Wet controls such as water or steam injection systems are readily available with most turbine vendors. Performance of a wet control alternative is affected by combustor geometry, injection nozzle design, and fuel bound nitrogen content. In order to derive maximum control system performance, the injected water must be atomized and sprayed in a configuration that provides a homogeneous mixture of water droplets and fuel in the combustor. Water or steam injection for NO_X control is a feasible option. Water or steam injection typically results in NO_X emission levels of 25 to 42 ppmv. The GE LM6000 turbines can achieve NO_X emission levels of 25 ppmv.

Thus the only feasible control options for the proposed combustion turbines are $SCONO_x$™, SCR, DLN combustor, and water or steam injection. $SCONO_x$™ is the most effective of the four control options. SCR is the next most effective control option. DLN and water or steam injection have equivalent control efficiencies of 25 ppmv. These options are further analyzed in the order of their efficiencies to determine BACT. Since DLN and water or steam injection result in the same control, water or steam injection is only review based on the manufacturer recommending water or steam as the preferred method of control.

d) Environmental Impacts

This section discusses the environmental impacts of the technically feasible control options.

<u>$SCONO_x$™</u>

There are no significant environmental impacts from $SCONO_x$™ applications.

<u>Selective Catalytic Reduction</u>

Significant environmental impacts are associated with the use of an SCR system for NO_X control. These environmental impacts are summarized below:

SCR diminishes power output of the turbines due to pressure drop. Additional air pollutants will have to be emitted from some other power plant to make up for this wasted power;

Unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM_{10} precursor;

Small amounts of ammonium salts would be emitted to the atmosphere as PM_{10};

There are serious (albeit manageable) safety issues associated with the transportation, handling, and storage of aqueous ammonia. The storage of aqueous ammonia (which is substantially lower risk than for anhydrous ammonia) is regulated under Occupational Safety and Health Act (OSHA) regulations and the Risk Management Planning (RMP) provisions of Clean Air Act Amendments Title III, Section 112(r); and

The use of SCR technology could result in ammonia emissions of as much as 20 ppm due to unreacted ammonia leaving the SCR unit. It is important to note that ammonia slip levels vary over the life of the catalyst. With a fresh catalyst, slip levels of only a few ppm may be sufficient to maintain the permitted NO_X emission rate. As catalyst ages, more ammonia (slip) is required, up to the point that the catalyst must be replaced.

In summary, the transport, handling, and storage of aqueous ammonia presents limited environmental risks due to potential spills and subsequent evaporation of ammonia gas to the atmosphere. However, potential environmental impacts from the storage and handling of aqueous ammonia are not considered unreasonable for the GENCO Site.

Water or Steam Injection

There are no significant environmental impacts from steam or water injection.

e) Economic Evaluation

This section evaluates the economic feasibility of each control option. Economic feasibility may be evaluated by estimating the cost effectiveness of each control option. Cost effectiveness is the ratio of the annualized cost of the control option and the tons of pollutant removed. The total annualized cost is based on capital cost and annual operation costs. The capital cost includes equipment costs, other direct and indirect installation and startup costs. Capital costs are based on budgetary quotations from equipment manufacturers. The direct and indirect installation costs are percentages of equipment costs. Annual operating costs include catalyst replacement, energy impacts, operating personnel, annual operation and maintenance costs, reagents and chemical costs, and heat rate penalty. The heat rate penalty cost item reflects the cost due to the control device backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue.

$SCONO_X$™

$SCONO_X$™ capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, catalyst, and structural support. The total purchased equipment cost is based on a quote provided by Goal Line Technology (proposal dated June 15, 2000) and is $1,936,000. This includes the cost of temperature reduction system (heat exchangers) required for proper operation of the system. With other direct and indirect installation and start-up costs, the total capital cost for installing a $SCONO_X$™ system is estimated at $3,116,960.

The total annualized cost for operation of the $SCONO_X$™ system for each turbine is estimated at $863,249. The maximum amount of NO_X removed annually by the $SCONO_X$™ system would be 85 tons based on 4,000 hours of operation and an estimated removal efficiency of approximately 90 percent (reducing NO_X emissions from 30 ppm to 3.5 ppm). Therefore, the overall cost-effectiveness of the SCONOx™ system is calculated as approximately $10,180 per ton of NOx removed. Therefore, the SCONOx™ system is not a cost-effective technology for control of NOx from the proposed turbines at the GENCO Site.

Selective Catalytic Reduction

SCR capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, ammonia storage and distribution, catalyst, and structural support. The total purchased equipment cost is estimated at $1,475,600 based on a quote from Engelhard. With other direct and indirect installation and start-up costs, the total capital cost for installing an SCR system is estimated at $1,783,800.

The total annualized cost for operation of SCR for each turbine is estimated at $633,400. The maximum amount of NOx removed annually by SCR would be 69 tons based on 4,000 hours of operation and an estimated removal efficiency of approximately 70 percent (reducing NOx emissions from 30 ppm to 9 ppmv). Therefore, SCR has an overall cost-effectiveness of approximately $9,200 per ton of NOx removed. Therefore, SCR is not a cost-effective technology for control of NOx from the proposed turbines at the GENCO Site.

Water or Steam Injection

Water or steam injection is considered economically feasible and, therefore, is not reviewed here.

f) Proposed BACT for NO_X

The GE LM6000 turbines when equipped with water or steam injection results in NOx emissions of 25 ppmv. Based on the economic infeasibility of SCONOx™ and SCR for the proposed peaking application, water or steam injection with NOx emissions of 25 ppmv is proposed as BACT for this project.

g) Proposed BACT Review

Based on the costs associated with SCONOx™ and SCR, $10,180 and $9,200 per ton of NOx removed respectively, these controls are not economically effective.

Additionally, the proposed BACT was reviewed against BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC). The RBLC is a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), and lists technologies that have been approved in PSD permits as BACT for numerous process equipment. The purpose of the RBLC database search is to identify the emission control technologies and levels of NOx emissions that were determined by permitting authorities as BACT for combustion turbines of similar size. The search result does not include turbines 70 MW or larger since these are not aeroderivative models. The results of this search are listed below.

PERMIT ID	PERMIT ISSUED	PERMITTED ITEM	SIZE**	EMISSION LIMIT	CONTROL EQUIPMENT
FL-0109	9/28/95	Turbine relocation	23 MW	75 ppmv	Water injection
AL-0096	3/12/97	Combined cycle	25 MW	25 ppmv	DLN
CO-0037	1/4/99	Combined cycle	33 MW	15 ppmv	Pollution prevention
NM-0024	5/29/95	Turbine	33 MW	9 ppmv	DLN
WY-0039	2/27/98	Turbine	33 MW	25 ppmv	DLN
CO-0018	7/20/94	Turbine	35 MW	25 ppmv	DLN
MO-0013	7/27/95	Twin-pac turbine	35 MW	42 ppmv***	Water injection
LA-0093	3/7/97	Combined cycle	38 MW	9 ppmv	DLN
LA-0113	12/30/97	Turbine	38 MW	8 ppmv	Steam injection and SCR
CO-0019	12/30/97	Combined cycle	39 MW	42 ppmv	Water injection
CO-0017	7/26/96	Turbine*	40 MW	25 ppmv	Steam injection
WY-???	3/1/00	Turbine*	40 MW	25 ppmv	DLN
NM-0039	8/7/98	Combined cycle*	44 MW	15 ppm	Water injection and SCR
AR-???	2/28/00	Combined cycle*	46 MW	25 ppmv****	Steam injection
ME-0015	3/31/98	Combined cycle	49 MW	6 ppmv	DLN and SCR

* turbines are aeroderivative GE LM6000 models
** all sizes are simple cycle
*** 1-hour average
**** 22 ppmv, 12-month rolling average

As shown, the BACT determinations varied from 8 ppm to 75 ppm. The more recent determinations indicate a move to 25 ppm or less and only one recent determination has been made that requires additional controls (NM-0039). This source is a combined cycle system which results in the SCR controlling higher levels of NO_X providing a more cost effective SCR system.

Based on technically feasible controls, the historical BACT review, and the cost effectiveness of additional controls, BACT is accepted as water or steam injection with NO_X emissions of 25 ppmv corrected to 15% O_2.

SECTION IX. AIR QUALITY IMPACTS AND MONITORING (From Permit No. 2000-273-C (PSD))

The air quality impact analyses were conducted to determine if ambient impacts would result in a radius of impact being defined for the facility. If a radius of impact occurs 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.

Description of Air Quality Dispersion Model

The air quality modeling analyses employed USEPA's Industrial Source Complex Short Term Version 3 (ISC3) model. The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474).

The ISC3 model (Version 99155) consists of two programs: a short-term model (ISCST3) and a long-term model (ISCLT3). The difference in these programs is that the ISCST3 program utilizes an hourly meteorological data base, while ISCLT3 is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. The ISCST3 model was used. The regulatory default option, which includes stack heights adjusted for stack-tip downwash, buoyancy-induced dispersion, and final plume rise. Ground-level concentrations occurring during "calm" wind conditions are calculated by the model using the calm processing feature. Regulatory default values for wind profile exponents and vertical potential temperature gradients are used since no representative on-site meteorological data are available. As per U.S. EPA requirements, direction-specific building dimensions are used for both the Schulman-Scire and the Huber-Snyder downwash algorithms.

Additionally, the rural settings were used based on the area being made up of primarily cropland and pasture. Stack base elevation for the proposed units is 360 meters. All receptors that are below this elevation are raised to 360 meters to be conservative. All receptors that fall outside the 12 nearest quadrangles are set to stack base elevation.

GEP Stack Height and Plume Downwash

The emissions units at the GENCO site have been evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine if stack discharges might become caught in the turbulent wakes of these structures. Wind blowing around a building creates zones of turbulence that are greater than if the building were absent. The current version of the ISCST3 dispersion model provides for a revised treatment of building wake effects which, for certain emissions units, uses wind direction-specific building dimensions following the algorithms developed by Schulman and Hanna. The minimum stack height not subject to the effects of downwash is defined by the formula:

$$G = H + 1.5L$$

Where:
- G = Minimum Good Engineering Practice (GEP) stack height
- H = Height of the structure
- L = Lesser dimension (height or projected width of structure)

This equation is limited to stacks located within 5L of the structure. Stacks located at distances greater than 5L are not subject to the wake effects of the structure. If there is more than one stack at a given facility, the above equation must be successively applied to each stack. If more than one structure is involved, the equations must also be successively applied to each structure.

Direction-specific building dimensions and the dominant downwash structure parameters used as input to the dispersion models were determined using the *BREEZE-WAKE/BPIP* software, developed by Trinity Consultants. This software incorporates the algorithms of the U.S. EPA sanctioned Building Profile Input Program (BPIP), version 95086. BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.