ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation #26:

Permit #: 1987-AOP-R0

IS ISSUED TO:

Hot Spring Power Project
Hwy 270, 6 Miles West of Malvern
Malvern, AR 72104
Hot Spring County
AFIN: 30-00337

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

11/9/01 and 11/8/06

AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Keith A. Michaels Date Amended

SECTION I: FACILITY INFORMATION

PERMITTEE:	Hot Spring Power Project
AFIN:	30-00337
PERMIT NUMBER:	1987-AOP-R0
FACILITY ADDRESS:	Hwy 270, 6 Miles West of Malvern Malvern, AR 72104
COUNTY:	Hot Spring
CONTACT PERSON:	Brian Walls, P.E.
TELEPHONE NUMBER:	(713) 552-2259
REVIEWING ENGINEER:	Bryan Leamons
UTM North-South (Y):	3809.7
UTM East-West (X):	515.4
Zone:	15

SECTION II: INTRODUCTION

Summary of Permit Activity

Hot Spring Power Project, owned and operated by Hot Spring Power Company, LLC, is a 815-MW gas turbine/ steam turbine combined-cycle electric power plant in Hot Spring County. The facility is located on a 57-acre plot located north of Highway 270, approximately six miles west of Malvern. The facility is permitted to construct and operate two natural gas-fired combustion turbines with associated generators. Duct burners will be used for additional heat rate into the heat recovery steam generators which will supply steam for added plant efficiency. Other supporting equipment is also permitted. This supporting equipment includes a cooling tower and various insignificant activities. Insignificant activities include water treatment equipment with associated tanks, a diesel fire-water pump engine, and diesel storage tanks. See Section VII of this permit for the details of insignificant equipment.

Process Description

CT/ HRSG/ Duct Burners (SN-01and SN-02)

Ambient air is drawn through an air filtration intake structure into the inlet compressor section of the turbine, mixed with natural gas, and burned, which exhausts the hot gases through rows of stationary vanes and rotating blades. These hot exhaust gases turn the turbines and drive generators to produce electrical power for distribution. The combustion turbine is a Siemens/Westinghouse 501G unit capable of producing a nominal 230 MW of electricity. The exhaust gases then pass through the HRSG where boiler feed water will be converted into steam. The steam is used to drive a steam turbine which produces a nominal 230 MW to a maximum 350 MW of electricity. Each of the HRSGs is equipped with a duct burner to provide additional heat to generate 115 MW of electricity during peak demands. Collectively, two combustion gas turbine generators and a steam turbine form a combined cycle system for the power plant.

The facility incorporates a two-on-one configuration, two Siemens/Westinghouse 501G combustion turbines fired HRSGs and one steam turbine, to provide for a nominal generating capacity of 700 MW to a maximum capacity of 815 MW with the firing of the duct burners. The combustion turbines and duct burners are fired solely by natural gas. Normal operation consists of both combustion turbine and HRSG units operating at base load without supplemental firing from duct burners. The units are expected to operate continuously (8,760 hours per year), except for maintenance and repair activities or during periods of low electrical demand. The duct burners are fired to meet peak electrical demands at a maximum of 2,500 hours per year.
The generator turbine is a 60 hertz, single shaft machine. The design exhaust temperature for the turbine/fired HRSG is 185EF, varying with turbine conditions, ambient conditions, and

operational load. The shaft, connected to the generator, is totally enclosed. The turbine has a total heat consumption rate of approximately 2,200 MMBtu/hour, but this also varies with ambient conditions and operational load. The duct burners have a maximum firing rate of 600 MMBtu/hour, high heating value (HHV).

Good combustion controls along with natural gas firing are employed to reduce emissions of SO_2 and PM_{10}. An oxidation catalyst is used to reduce annual VOC and CO concentrations in the stack to 4.0 parts per million by volume dry (ppmvd) and 12.0 ppmvd, respectively corrected to 15% oxygen, while operating at ambient conditions at base load operations. Dry low-NO_x (DLN) technology, coupled with a selective catalytic reduction (SCR) unit, is used to minimize combustion turbine and duct burner NO_x emissions to 3.5 ppmvd, corrected to 15% oxygen, for natural gas firing. The operation of the SCR involves the injection of aqueous ammonia into the exhaust gas stream ahead of a catalyst bed.

Ammonia Storage (Insignificant)

Aqueous ammonia (28 wt.% solution) arrives on-site via tank truck. The truck is off-loaded into one of two 12,000-gallon capacity horizontal vessels for storage. These vessels are equipped with a pressure vent valve with settings to minimize standing loss emissions. These tanks are insignificant sources, see Section VII.

The aqueous ammonia is then pumped from the storage vessel to an ammonia injection skid via aboveground piping. The aqueous ammonia is injected through a series of nozzles into the exhaust gas stream within the HRSG just upstream of the catalyst.

The combustion emissions from the turbines and duct burner vents to the HRSGs where the exhaust gas passes through the oxidation catalyst, then the SCR. After passing through the SCR, the exhaust gas is vented to the atmosphere through a dedicated stack, for a total of two stacks (SN-01 and SN-02).

Water Treatment (Insignificant)

Raw water is demineralized through an on-site water treatment system and stored in aboveground tankage. The demineralized water is routed to the fired HRSG for steam production. The water treatment sources are insignificant, see Section VII.

Cooling Tower (SN-04 through SN-15)

Cooling water used in the condensers is provided by a mechanical draft wet cooling tower with twelve cells (SN-04 through SN-15). The condensers are used to condense the steam across the steam turbine to promote efficiency. Routine water treatment chemicals will be utilized in the cooling tower to promote efficient operation.

Emergency Diesel Fire Water Pump (Insignificant Emission Source)

An emergency diesel engine driven fire water pump is used when power is unavailable or during routine testing. Emissions from this diesel engine are inherently low because of a relative short operation time. The operations of the emergency diesel engine driven fire water pump and its associated storage tank are insignificant activities, see Section VII of this permit.

Regulations

This facility is subject to the following state and federal regulations:

- *Arkansas Air Pollution Control Code* (Regulation 18);
- *Regulations of the Arkansas Plan of Implementation for Air Pollution Control* (Regulation 19);
- *Regulations of the Arkansas Operating Permit Program* (Regulation 26);
- New Source Performance Standards (NSPS):
  40 CFR Part 60, Subpart GG, *Standards of Performance for Stationary Gas Turbines*;
  40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*;
  40 CFR Part 60, Subpart Dc, *Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units*;
- Federal Acid Rain Program - 40 CFR Part 75, *Continuous Emission Monitoring*.

This facility is considered a major source with respect to Title V and Prevention of Significant Deterioration (PSD) Permitting. The facility is classified as one of the 28 PSD named source categories.

Prevention of Significant Deterioration

As previously noted, the facility is subject to PSD review as part of the Title V permitting process. This review requires the application of Best Available Control Technology (BACT) and an air quality analysis of facility emissions sources to ensure compliance with NAAQS and to assess increment consumption.

The facility is a fossil-fuel fired steam-generating electric utility with heat input greater than 250 MM Btu/hr. These facilities are specifically listed on the PSD 28-list of named source categories and the facility is therefore considered a major source because it emits one or more regulated pollutants in quantities greater than 100 tpy.

The following table compares PSD Significant Emission Rates to permitted facility emissions. The facility must undergo full review for all of these pollutants with the exception of SO_2.

Pollutant	PSD Significant Emission Increase (tpy)	Emissions Increase (tpy)
PM_{10}	15	240.1
SO_2	40	13.2
Ozone	40 tpy of VOC	63.4 tpy of VOC
CO	100	615.0
NO_2	40 tpy of NO_x	294.6 tpy of NO_x

BACT Analysis

A BACT determination is a case-by-case analysis that addresses the technological question of whether a proposed control technique can be considered BACT for the particular application or whether a more stringent level of emission control should be used. This determination involves an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission, as well as weighing the economic, energy, and environmental impacts using each technology.

The methodology used by the permittee to determine BACT followed the "top-down" approach. The "top-down" BACT contains the following elements:

- Determination of the most stringent control alternatives potentially available;
- Discussion of the technical and economic feasibility of each alternative;

C Assessment of energy and environmental impacts, including toxic and hazardous pollutant impacts, of feasible alternatives;
C Selection of the most stringent control alternative that is technically and economically feasible and that provides the best overall control of all pollutants.

The selected BACT must be at least as stringent as New Source Performance Standards for the source.

Guidance for BACT determinations can also be found using the EPA *RACT/BACT/LAER Clearinghouse* (RBLC) of control technology determinations. This database of determinations is useful when comparing past control technology determinations with that of a similar sized proposed new source. Determinations should be consistent with the RBLC unless there are site-specific conditions that affect the decision.

BACT for CO - CT/ HRSG/ Duct Burner

Overview

The formation of CO during combustion is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion including insufficient oxygen availability, poor air/fuel mixing, cold wall flame quenching reduced combustion temperature, decreased combustion residence time, and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

After combustion control, the only practical control method to reduce CO emissions from the combustion turbine and duct fired HRSG is the use of an oxidation catalyst. Exhaust gases from the combustion turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide (CO_2). Temperatures at the exhaust of the combustion turbine and duct fired HRSG are generally appropriate for effective oxidation catalyst operation. CO removal efficiencies can generally be guaranteed up to 75 %, although CO removal efficiency may be less at low inlet concentrations.

The top down BACT review has indicated that LAER for combustion turbines is 2.0 ppmvd, corrected to 15% oxygen. Hot Spring Power Company, L.L.C. is proposing a BACT for CO of 12.0 ppmvd, corrected to 15% oxygen. The top tier LAER control technology and the proposed BACT control technology require the installation and operation of an oxidation catalyst to achieve the corresponding CO level. The base case control technology is combustion air flow controls with no post combustion control for a CO concentration of 41.0 ppmvd, corrected to 15% oxygen.

Technical Feasibility

1) Combustion Air Flow - 41.0 ppmvd @ 15% O_2

Combustion air flow controls include good combustion practices, such as proper design, performing recommended preventative maintenance, and proper facility operation. These practices promote efficient combustion and, thus, inherently reduce the formation of CO in turbines. Combustion air flow controls are considered a technically feasible control alternative for CO emissions for the Hot Spring Power Project. The CO concentration of a combustion turbine duct fired HRSG before post combustion controls is 41.0 ppmvd, corrected to 15% oxygen.

2) Catalytic Oxidation - 12.0 ppmvd @ 15% O_2

In catalytic oxidation, combustion exhaust gas passes through a catalyst bed (typically platinum is the primary catalytic material) where the oxidation of CO to CO_2 takes place. Hydrocarbons (VOC) that are present in the exhaust gas are also oxidized to CO_2 and water vapor. Catalytic oxidation is capable of reducing CO levels by up to 75%. The temperature window for effective CO reduction for an oxidation unit is between 600E to 925EF. The location of the CO catalyst ,therefore, is critical for efficient operation. The catalyst could be located downstream of the combustion turbine and duct burners. Catalytic oxidation is considered a technically feasible control alternative for achieving CO concentrations of 12.0 ppmvd corrected to 15% oxygen for the Hot Spring Power Project.

7) Catalytic Oxidation - 2 ppmvd @ 15% O_2

This technology is the same as described previously for catalytic oxidation; however, more available catalyst surface contact area is required to reduce CO concentrations to this level. The increased catalyst surface area results in increased back pressure on the combustion turbine from the exhaust. This back pressure will result in lowered efficiency and turbine output; however, the implementation of catalytic oxidation to achieve a CO exhaust gas concentration of 2.0 ppmvd, corrected to 15% oxygen, is considered a technically feasible control alternative for CO emissions for the Hot Spring Power Project.

Control Alternatives Hierarchy

The following table ranks the technically feasible control alternatives according to the level of control. The following table ranks the control alternatives from highest level of control to lowest level of control, i.e, "top down."

CO Control Alternatives Hierarchy

Control Alternatives	**CO Concentration after Control (ppmvd @ 15% O_2)**	**CO Annual Emission Rate after Control (Tpy)**
CO Oxidation Catalyst	2.0	51.25
CO Oxidation Catalyst	12.0	307.49
Combustion Controls	41.0	1,033.25

Energy Impacts

1) Combustion Air Flow - 41.0 ppmvd @ 15% O_2

Combustion air flow controls include good combustion practices, including proper design, performing recommended preventative maintenance, and proper facility operation that require no additional energy; therefore, this alternative has little or no energy impacts.

2) Catalytic Oxidation - 12.0 ppmvd @ 15% O_2

The catalyst used in the oxidation system results in an increase in the back pressure of the turbine exhaust. The resultant back pressure corresponds to a subsequent performance loss in available turbine output; therefore, use of catalytic oxidation would require additional fuel (natural gas) input to maintain the same available combustion turbine output as a combustion turbine using no controls. The reduced output has been estimated to have a potential negative impact of over 1,200 MW annually.

3) Catalytic Oxidation - 2.0 ppmvd @ 15% O_2

The increased catalyst surface area results in an even greater pressure drop across the catalyst bed, therefore, increasing the back pressure on the combustion turbine from the exhaust. This back pressure will result in lowered efficiency and turbine output; therefore, use of catalytic oxidation to achieve a CO concentration of 2.0 ppmvd, corrected to 15% oxygen, would require an even greater natural gas input to maintain the same available turbine output as a turbine that maintains a CO concentration of 12.0

ppmvd, corrected to 15% oxygen. The reduced output has been estimated to have a potentially negative impact of over 3,000 MW annually.

Cost/Economic Impacts

Cost effectiveness, in terms of dollars per ton of CO emission reduction, is a key criteria used to assess the economic feasibility of a control alternative. By expressing costs in terms of the amount of emission reduction achieved, comparisons can be performed.

Cost effectiveness is calculated as the annualized cost of the CO control option being considered divided by the baseline minus the control option emissions rate, as shown by the following formula:

$$\text{Cost Effectiveness (\$/ton removed)} = \frac{\text{CO control option annualized cost}}{\text{Base case emissions rate - CO Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr), and emissions rates are calculated in tons per year (tpy). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of CO removed.

The annualized costs have been estimated in accordance with the Office of Air Quality Planning and Standards (OAQPS), Control Cost Manual, (EPA, 1996). The basis for the equipment cost estimates have been derived from either equipment vendors or similar projects. The other direct and indirect operating costs have been estimated based upon guidance from the Control Cost Manual and Office of Air Quality Planning and Standards, Alternative Control Techniques Document - NO_X Emissions from Stationary Combustion turbines, EPA-453/R-93-007, January 1993.

The base case control is the implementation of combustion air flow controls to achieve a CO concentration of 41.0 ppmvd, corrected to 15% oxygen. The proposed control for the turbine is the implementation and operation of a CO oxidation catalyst capable of achieving a CO concentration of 12.0 ppmvd, corrected to 15% oxygen. The alternative control technology for CO is the implementation and operation of a CO oxidation catalyst capable of achieving a CO concentration of 2.0 ppmvd, corrected to 15% oxygen. The proposed and alternative cases have been compared to the base case to determine the cost effectiveness.

The estimated direct and indirect operating costs for the implementation of catalytic oxidation technology for the Hot Spring Power Project have been identified in the application. The table below summarizes the results of the cost analysis.

CO Control Cost Analysis Summary			
Control Alternatives	**CO Concentration after Control (ppmvd @ 15% O_2)**	**CO Annual Emission Rate after Control (Tpy)**	**Cost Effectiveness over Base Control ($/ton Removed)**
CO Oxidation Catalyst	2.0	51.25	$4,913
CO Oxidation Catalyst	12.0	307.49	$3,373
Combustion Controls	41.0	1,033.25	$0

Environmental Impacts

1) Combustion Air Flow - 41.0 ppmvd @ 15% O_2

Combustion air flow controls include good combustion practices, such as proper design, performing recommended preventative maintenance, and proper facility operation. They will have little or no environmental impacts.

2) Catalytic Oxidation - 12.0 ppmvd @ 15% O_2

The catalyst used to control CO combustion emissions has a guaranteed life of three years. As such, catalytic oxidation applications generate a solid waste in the form of spent catalyst that requires treatment and disposal. The spent catalyst may undergo metal recovery; however, the potential exists for waste disposal requirements for the non-recoverable metal portion of the spent catalyst. Depending upon the character and composition of the non-recoverable portion of the spent catalyst, it may be subjected to the hazardous waste regulations pursuant to Resource Conservation and Recovery Act (RCRA). As a result, disposal of spent catalyst would pose additional economic costs and potential environmental liabilities for Hot Spring Power Company, L.L.C.

As the spent catalyst would need to be replaced on a three year cycle, the turbine would need to be shut down and taken off-line for this activity. The catalyst replacement may be scheduled during other required maintenance or downtime activities. There is the potential that the catalyst replacement would not correspond to any other planned maintenance activity; therefore, the turbine would experience the increased emissions from shut-down and start-up operations that would be a direct result of catalyst replacement.

3) Catalytic Oxidation - 2.0 ppmvd @ 15% O_2

> As this control alternative is similar to the CO oxidation catalyst discussed above, the environmental issues would be similar. The difference between the environmental impacts of two alternatives would be in the volume of waste generated. As more catalyst is required to achieve the lower CO concentrations, more spent catalyst is generated during the replacement operations. The replacement times are expected to be comparable.

Conclusion

It is evident from the analysis that the installation of a catalytic oxidation unit capable of achieving a combustion turbine exhaust gas CO concentration of 2.0 ppmvd, corrected to 15% oxygen, provides for a lower emission rate than the proposed and base case control technology. The proposed case control technology proposed for the Hot Spring Power Project is a catalytic oxidation unit capable of achieving a combustion turbine duct fired HRSG exhaust gas CO concentration of 12.0 ppmvd, corrected to 15% oxygen. As the proposed control methodology is to meet BACT and not LAER, a less stringent technology may be implemented if the most stringent technology is not achievable based on an objective analysis of the potential energy, economic, and environmental impacts.

As discussed previously, the use of a catalytic oxidation unit results in an increase in the back pressure of the turbine exhaust. The resultant back pressure corresponds to a subsequent performance loss in available turbine output; therefore, use of catalytic oxidation would require additional natural gas input to maintain the same available turbine output as a turbine using no controls. Based upon the engineering design of a catalytic oxidation unit capable of achieving a combustion turbine exhaust gas CO concentration of 2.0 ppmvd, corrected to 15% oxygen, this alternative would result in reduced turbine output compared to the proposed control alternative.

The environmental impacts for the top tier and proposed controls are relatively the same in that both would generate a spent catalyst waste during catalyst replacement; however, the more stringent control technology, a catalytic oxidation unit capable of achieving a combustion turbine exhaust gas CO concentration of 2.0 ppmvd, corrected to 15%, would generate more spent catalyst over its lifetime; therefore, the implementation of the proposed control technology would result in a lesser environmental impact compared to the more stringent technology.

Cost effectiveness is the criterion used to assess cost or economic impacts of the control technologies identified for minimizing CO emissions. The cost effectiveness calculations utilized for this BACT analysis has been conducted on an average basis. Average cost effectiveness (total annualized costs of control divided by annual emissions reductions, or the difference between the baseline emission rate and the controlled emission rate) has been estimated comparing the proposed BACT controls and the alternative CO control against the base case control (i.e. no post-combustion control equipment).

In general, study cost estimates used in BACT are typically accurate to " 20 to 30 percent. USEPA's draft " New Source Review Workshop Manual - Prevention of Significant Deterioration, October 1990" states that cost options that are within this " 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options. From the CO Control Cost Analysis Summary table, the cost per ton of pollutant removed for the alternative control technology (i.e. oxidation catalyst capable of achieving a CO concentration of 2.0 ppmvd, corrected to 15% oxygen) is approximately 45% higher than the proposed BACT controls (i.e. oxidation catalyst capable of achieving a CO concentration of 12.0 ppmvd, corrected to 15% oxygen). Thus, the impacts of the control alternative technology as BACT are economically unfeasible.

The results of the top down BACT review identified three potential control alternatives for minimizing emissions of CO from the combustion turbines. The proposed case control has been deemed a viable alternative based on the evaluation of energy, economic, and environmental impacts; therefore, Hot Spring Power Company, L.L.C. is proposing that the implementation of a catalytic oxidation unit capable of achieving a combustion turbine exhaust gas CO concentration of 12.0 ppmvd, corrected to 15% oxygen, to be considered the BACT for the combustion turbines and duct fired HRSGs.

<u>BACT for VOC - CT/ HRSG/ Duct Burner</u>

Overview

VOC emissions result from incomplete combustion of the heavier molecular weight components of the natural gas fuel. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

Technical Feasibility

1) <u>Combustion Air Flow - 5.11 ppmvd @ 15% O_2</u>

Combustion air flow controls include good combustion practices, such as proper design, performing recommended preventative maintenance, and proper facility operation. These practices promote efficient combustion and, thus, inherently reduce the formation of VOC in combustion turbines. Combustion air flow controls are considered a technically feasible control alternative for VOC emissions for the Hot Spring Power Project. The

VOC concentration of a combustion turbine duct fired HRSG before post combustion controls is 5.11 ppmvd, corrected to 15% oxygen.

2) Catalytic Oxidation - 4.0 ppmvd @ 15% O_2

In catalytic oxidation, combustion exhaust gas passes through a catalyst bed (typically platinum is the primary catalytic material) where the hydrocarbons (VOC) that are present in the exhaust gas are also oxidized to CO_2 and water vapor. Catalytic oxidation is capable of reducing VOC levels by up to 22%. Catalytic oxidation is considered a technically feasible control alternative for achieving VOC concentrations of 4.0 ppmvd corrected to 15% oxygen for the Hot Spring Power Project.

Control Alternatives

The following table ranks the technically feasible control alternatives according to the level of control. The following table ranks the control alternatives from highest level of control to lowest level of control, i.e, “top down.”

VOC Control Alternatives Hierarchy

Control Alternatives	**VOC Concentration after Control (ppmvd @ 15% O_2)**	**VOC Annual Emission Rate after Control (tpy)**
Oxidation Catalyst	4.0	31.69
Combustion Controls	5.11	40.65

Energy Impacts

1) Combustion Air Flow - 5.11 ppmvd @ 15% O_2

Combustion air flow controls include good combustion practices such as proper design, performing recommended preventive maintenance, and proper facility operation. These require no additional energy have little or no energy impacts.

2) Catalytic Oxidation - 4.0 ppmvd @ 15% O_2

The catalyst used in the oxidation system results in an increase in the back pressure of the turbine exhaust. The resultant back pressure corresponds to a subsequent performance loss in available turbine output; therefore, use of catalytic oxidation would require additional fuel (natural gas) input to maintain the same available combustion turbine output as a combustion turbine using no controls. The reduced output has been estimated to have a potential negative impact of over 1,200 MW annually.

Cost/Economic Impacts

Cost effectiveness, in terms of dollars per ton of VOC emission reduction, is a key criteria used to assess the economic feasibility of a control alternative. By expressing costs in terms of the amount of emission reduction achieved, comparisons can be performed.

Cost effectiveness is calculated as the annualized cost of the VOC control option being considered divided by the baseline minus the control option emissions rate, as shown by the following formula:

$$\text{Cost Effectiveness (\$/ton removed)} = \frac{\text{Control option annualized cost}}{\text{Base case emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr), and emissions rates are calculated in tons per year (tpy). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of VOC removed.

The annualized costs have been estimated in accordance with the OAQPS, Control Cost Manual, (EPA, 1996). The basis for the equipment cost estimates have been derived from either equipment vendors or similar projects. The other direct and indirect operating costs have been estimated based upon guidance from the Control Cost Manual and Office of Air Quality Planning and Standards, Alternative Control Techniques Document - NO_X Emissions from Stationary Combustion turbines, EPA-453/R-93-007, January 1993.

The proposed control for the turbine is the implementation and operation of an oxidation catalyst capable of achieving a VOC concentration of 4.0 ppmvd, corrected to 15% oxygen. The base control technology for VOC (i.e. combustion controls) capable of achieving a VOC concentration of 5.11 ppmvd, corrected to 15% oxygen, has been compared to the proposed case to determine the cost effectiveness.

The estimated direct and indirect operating costs for the implementation of catalytic oxidation technology for the Hot Spring Power Project have been identified in the application. The table below summarizes the results of the cost analysis.

VOC Control Cost Analysis Summary

Control Alternatives	VOC Concentration after Control (ppmvd @ 15% O_2)	VOC Annual Emission Rate after Control (tpy)	Incremental Cost Effectiveness over Base Case ($/ton Removed)
Oxidation Catalyst	4.0	31.69	$302,191
Combustion Controls	5.11	40.65	$0

Environmental Impacts

1) Combustion Air Flow - 5.11 ppmvd @ 15% O_2

Combustion air flow controls include good combustion practices, such as proper design, performing recommended preventative maintenance, and proper facility operation that will have little or no environmental impacts.

2) Catalytic Oxidation - 4.0 ppmvd @ 15% O_2

The catalyst used to control VOC combustion emissions has a guaranteed life of three years. As such, catalytic oxidation applications generate a solid waste in the form of spent catalyst that requires treatment and disposal. The spent catalyst may undergo metal recovery; however, the potential exists for waste disposal requirements for the non-recoverable metal portion of the spent catalyst. Depending upon the character and composition of the non-recoverable portion of the spent catalyst, it may be subjected to the hazardous waste regulations pursuant to Resource Conservation and Recovery Act (RCRA). As a result, disposal of spent catalyst would pose additional economic costs and potential environmental liabilities for Hot Spring Power Company, L.L.C.

As the spent catalyst would need to be replaced on a three year cycle, the turbine would need to be shut down and taken off-line for this activity. The catalyst replacement may be scheduled during other required maintenance or downtime activities. There is the potential that the catalyst replacement would not correspond to any other planned maintenance activity; therefore, the turbine would experience the increased emissions from shut-down and start-up operations that would be a direct result of catalyst replacement.

Conclusion

The control technology proposed for the Hot Spring Power Project is a catalytic oxidation unit capable of achieving a combustion turbine duct fired HRSG exhaust gas VOC concentration of 4.0 ppmvd, corrected to 15% oxygen. As the proposed control methodology is to meet BACT and not LAER, a less stringent technology may be implemented if the most stringent technology is not achievable based on an objective analysis of the potential energy, economic, and environmental impacts.

The incremental cost effectiveness to achieve 4.0 ppmvd corrected to 15% oxygen has been estimated at $302,191.00 per ton. This incremental cost effectiveness reflects the cost differential of achieving 4.0 ppmvd vs. 5.11 ppmvd per ton of VOC. Although the incremental cost effectiveness appears to be excessive, it is important to note that an oxidation catalyst has been identified as BACT for CO emissions from combustion turbines and duct fired HRSGs. VOC reduction from the use of an oxidation catalyst is an incidental benefit from the primary target of controlling CO emissions. Clearly the BACT review indicates that the use of an oxidation catalyst for the sole purpose of VOC reduction is not economically viable.

The environmental impacts for the base case technology - no post combustion controls are minimal, while the use of post combustion controls will generate a spent catalyst requiring disposal. The results of the top down BACT review identified two potential control alternatives for minimizing emissions of VOC from the combustion turbines/ HRSGs. Hot Spring Power Company, L.L.C. is proposing that the implementation of a catalytic oxidation unit capable of achieving a combustion turbine exhaust gas VOC concentration of 4.0 ppmvd, corrected to 15% oxygen, be considered the BACT for the combustion turbines and duct fired HRSGs.

BACT for NO_x - CT/ HRSG/ Duct Burner

Overview

The formation of NOx is determined by the interaction of a chemical and physical process occurring within the unit combustion chamber. There are two principal forms of NOx, designated as "thermal" NOx and "fuel" NOx. Thermal NOx formation is the result of the oxidation of atmospheric nitrogen contained in the combustion air in the high-temperature, post-flame region of the combustion zone. The major factors influencing thermal NOx formation are temperature, concentrations of nitrogen and oxygen in the combustion air, and residence time within the combustion zone. Fuel NOx is formed by the oxidation of fuel-bound nitrogen. During combustion, the nitrogen content of the fuel is liberated and then participates in NOx reactions in the combustion chamber.

Natural gas is the primary fuel to be fired in the turbine and duct-fired HRSG. Typically, natural gas contains negligible amounts of nitrogen. Given the high nitrogen content of combustion air, fuel-bound nitrogen is an insignificant contributor to overall NOx emissions; therefore, since most of the NOx formed during the combustion of natural gas is due to atmospheric nitrogen, fuel treatments are not considered in this analysis.

Reductions in NOx emissions can generally be achieved using either combustion controls or flue gas treatment. DLN combustors and water/steam injection for the turbine are examples of combustion controls. Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are examples of flue gas treatment.

The top down BACT review has indicated that LAER for combustion turbines is 2.0 ppmvd, corrected to 15% oxygen for smaller F class combustion turbines. Hot Spring Power Company, L.L.C. is proposing a BACT for NOx of 3.5 ppmvd. The top tier LAER control technology and the proposed BACT control technology require the installation and operation of an oxidation catalyst to achieve the corresponding NOx level. The base case control technology is DLN combustor technology with no post combustion control for a NOx concentration of 25.47 ppmvd, corrected to 15% oxygen.

Technical Feasibility

1) <u>Water Injection</u>

Water injection and steam injection are the most common NOx control technologies for combustion turbines. Water injection involves introducing water directly into the combustion chamber of the turbine, thus lowering the flame temperature, a major factor in NOx formation and reducing thermal NOx. This is accomplished by injection through separate annular spaces in the fuel manifold. A water injection system typically consists of a water treatment system, pumps, water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Obviously, water purity is essential to prevent or minimize erosion and/or the formation of deposits in the hot section of the turbine. Injection of water during gas fired operation is generally capable of reduction full load exhaust gas NO_X emissions to approximately 25 ppmvd, corrected to 15% oxygen. Since water injection alone results in NO_X emissions which are higher than the level considered to be BACT (25 ppm vs. 3.5 ppm), water injection will not be considered as a valuable NO_X control method for the Hot Spring Power Project combustion turbine, and will not be evaluated further.

2) Steam Injection

Steam replaces water as the injected fluid in a steam injection system. The injection system is similar to that for water injection, but the pump is replaced by a steam producing boiler. The unfired HRSG could generate the required steam. The balance of the steam system is similar to the water injection system. The water treatment required for the unfired HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_X control generally requires that additional capacity be included in the boiler feed water treatment system. Injection of steam during natural gas firing is generally capable of reducing full load exhaust gas NO_X emissions to approximately 25 ppmvd, corrected to 15% oxygen. This level results in higher NO_X emissions than the level considered BACT (25 ppm vs. 3.5 ppm); therefore, steam injection will not be considered as a viable NO_X control method for the Hot Spring Power Project combustion turbine, and will not be evaluated further.

3) Dry Low-NO_X (DLN) Combustor

Increasing the air to fuel ratio in the combustion chamber and staging the introduction of the air to the combustion zone results in lower combustion temperatures (a major factor in NO_X formation), thus lower NO_X formation. DLN technology is regarded as a major advance over water and steam injection technologies. It limits NO_X emission through combustion designs which promote a “lean-premixed” flame in the combustion chamber. In this manner, “staged” or “scheduled” combustion serves to significantly reduce thermal NO_X formation. NO_X emission from the Siemens/Westinghouse 501G can be controlled to 25 ppmvd, corrected to 15% oxygen, for natural gas firing. Since using DLN technology alone results in NO_X emissions which are higher than the level considered BACT (25 ppm vs. 3.5 ppm), DLN technology will not be considered as a viable stand alone NO_X control method for the Hot Spring Power Project combustion turbines.

4) Selective Catalytic Reduction (SCR) - 2.0 - 3.5 ppmvd @ 15% O_2

SCR is an add-on NO_x control technology that is placed in the exhaust stream following the combustion unit. SCR involves the injection of ammonia (NH_3) into the exhaust gas stream ahead of a catalyst bed. The ammonia reacts on the catalyst surface with NO_x to form nitrogen gas (N_2) and water (H_2O) according to the following chemical equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The catalyst's active surface is usually a noble metal (platinum), a base metal (titanium or vanadium), or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path in order to achieve maximum conversion efficiency and minimum back pressure on the combustion unit. The most common configuration of the catalyst is a honeycomb design. The base-metal catalysts are most commonly used in combustion turbine SCR applications. The placement of the catalyst is dependent upon the proper operating range for the catalyst. Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 400EF to 800EF. In a typical ammonia injection system, ammonia is stored in an on-site storage tank where it is piped to the SCR system. The ammonia is vaporized and injected upstream of the catalyst bed. Unreacted ammonia in the catalyst bed is emitted with the stack gas, and typically is referred to as ammonia slip. SCRs are capable of achieving NO_x concentrations as low as 2.0 ppmvd, corrected to 15% oxygen, to meet LAER for smaller F class combustion turbines. It is uncertain at this early project development stage that an SCR alone can achieve this low concentration for NO_x from the Siemens/Westinghouse 501G combustion turbine. It is likely that to achieve this lower emission level, an alternate technology may be employed. There have been no vendor guarantees for an SCR capable of achieving NO_x concentrations of 2.0 ppmvd corrected to 15% oxygen provided for this project; therefore, for the purposes of this BACT evaluation, it has been assumed an SCR can achieve these lower NO_x concentrations. With a slightly smaller catalyst bed and subsequent smaller consumption of ammonia, an SCR is capable of achieving NO_x concentrations of 3.5 ppmvd corrected to 15% oxygen for the Siemens/Westinghouse 501G combustion turbine. This project has vendor guarantees for an SCR capable of NO_x concentrations of 3.5 ppmvd, corrected to 15% oxygen. This concentration is being proposed as the base case control alternative to meet BACT; therefore, this technology is considered a technically feasible control alternative for control of NO_x emissions for the Hot Spring Power Project.

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

SNCR utilizes direct injection of ammonia or urea at high flue gas temperatures (1,600EF - 1,800EF) to reduce emissions of NO_x. The Engelhard NO_xCAT^{TM} VNX^{TM} SCR NO_x Abatement Catalyst System utilizes ammonia injection, while a second type of SNCR utilizes urea and avoids the ammonia storage and handling concerns. The combustion turbine exhaust for the proposed project is anticipated to be in the range of 1,000EF to 1,100EF; therefore, this technology is not considered a feasible control method for NO_x emissions for the Hot Spring Power Project due to the high operating temperature range.

6) XONON™

An emerging technology which is potentially capable of reducing gas turbine NO_x emissions to 3 ppm or less is catalytic combustion. This technology has been introduced commercially by Catalytica Combustion Systems, Inc., and is being marketed under the name, XONON™. This technology prevents NO_x formation through the use of a proprietary catalyst module (the XONON™ Module) within the combustor to reduce peak combustion temperatures, thereby inhibiting thermal NO_x formation. The XONON™ Module is integral to the gas turbine combustor. With the XONON™ system, a portion of the fuel is combusted flamelessly within the catalyst module, followed by completion of the combustion process downstream of the catalyst.

The basic research and development of the XONON™ Combustion System has been completed and the technology has been confirmed on test stands. The technology is currently being commercialized on small scale projects with support from the US DOE, the California Energy Commission, the California Air Resources Board (CARB) and the Gas Research Institute. According to Catalytica, this technology is designed to provide NO_x levels below 3 ppmvd @ 15% O_2. The CARB has reported that a demonstration of this technology on a 1.5 MW simple-cycle pilot facility is underway in Santa Clara, where NO_x emission levels of 1.3 to 4 ppmvd @ 15% O_2 have been achieved.

While XONON™is being sold commercially for certain (mostly smaller) engine models, it has not been demonstrated in 230 MW class turbines. Recently, ENRON North America announced construction of the 750 MW Patoria Energy Facility on the Tejon Ranch, near Bakersfield, California. The new facility will incorporate General Electric 7FA combustion turbines. The XONON™ Combustion System has been specified in the permit application as the "preferred emissions control system." If approval is received from the California Energy Commission, construction could begin in 2001, working toward commercial operation in the summer of 2003. As the application has not yet been approved, this technology is not currently a permit option. Obviously, this technology has not yet been demonstrated at this location. In summary, the XONON™ technology has not been demonstrated in practice for the size of turbines proposed for the Hot Spring Power Project; therefore, this technology does not currently represent BACT.

7) <u>SCONOx™</u>

Another emerging technology, SCONOx™ offers the promise of reducing combustion turbine NOx emissions to values in the range of 2.0 - 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 that NOx emissions have been demonstrated as low as 2.5 ppm.

SCONOx™ is produced by Goal Line Environmental Technologies, L.L.C. for combustion turbine applications. ABB Alstom Power is the sole licensee of SCONOx™ for large combustion turbines over 100 MW. This system uses a coated catalyst to oxidize both NOx and CO emissions without a reagent. The system utilizes a dilute hydrogen mixture (which is created by reforming natural gas with steam) in a proprietary catalyst regeneration process. The system consists of a platinum based catalyst coated with potassium carbonate (K_2CO_3) installed in the flue gas at a point where the temperature is between 300EF and 700EF.

CO emissions are decreased by the oxidation of CO to CO_2 (see equation [1] below). The CO_2 is simply exhausted to the atmosphere through the stack.

$$CO + \frac{1}{2}O_2 \text{ ÿ } CO_2 \qquad [1]$$

A multiple step process decreases NO and NO_2 emissions. NO emissions are oxidized to NO_2 and then adsorbed onto the catalyst (see equations [2] and [3]).

$$NO + \frac{1}{2}O_2 \text{ ÿ } NO_2 \qquad [2]$$
$$2NO_2 + K_2CO_3 \text{ ÿ } CO_2 + KNO_2 + KNO_3 \qquad [3]$$

When all of the potassium carbonate absorber coating on the surface of the catalyst has been reacted to nitrogen compounds, NOx will no longer be adsorbed, and the catalyst must be regenerated. A regeneration gas is used to regenerate the catalyst. The regeneration gas is produced from natural gas (see equation [4] and [5]). For systems where the SCONOx™ catalyst is located in an area with low flue gas temperatures (less than about 600EF), the regeneration gas is produced by processing natural gas through a separate, external, skid mounted reformer. For systems where the SCONOx™ catalyst is located in an area with flue gas temperatures at approximately 600EF and above (up to 700EF), the regeneration gas can be produced in the flue gas. In the high temperature case, a separate processing unit is not required. The resulting regeneration gas is approximately 3 percent nitrogen, 1.5 percent CO_2, and 4 percent H_2, with steam making up the balance (the steam is used as a carrier). Low concentrations of both hydrogen and oxygen reduce the risk of explosion. Homogeneous distribution of the regeneration gas over the surface of the catalyst is critical.

$CH_4 + ½O_2 \text{ ÿ } CO + 2H_2$ [4]
$CO + 2H_2 + H_2O \text{ ÿ } CO_2 + 3H_2$ [5]

The hydrogen in the regeneration gas reacts with the nitrites and nitrates that result from NO_2 being adsorbed by the catalyst. The reaction of hydrogen with nitrites and nitrates produces water vapor and elemental nitrogen gas (see equation [6]), which are exhausted to the atmosphere. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the adsorber coating on the surface of the catalyst before the process began. The potassium carbonate remains on the catalyst surface, and so there is no net gain or loss of potassium carbonate as a result of the process.

$KNO_2 + KNO_3 + 4H_2 + CO_2 \text{ ÿ } K_2CO_3 + 4H20(g) + N_2$ [6]

During the regeneration process, dampers isolate the portion of the catalyst bed targeted for regeneration. In this way, the portion of the catalyst bed being regenerated is isolated from the exhaust gas stream, during which period it is out of service. The remainder of the catalyst bed remains exposed to the exhaust gas and continues to adsorb NOx and CO as described above. After the isolated portion has been regenerated, the dampers open and that catalyst portion is again exposed to the exhaust gas. A different portion of the catalyst bed is then isolated and regenerated and so on, in a continuously repeating cycle. Each section of catalyst is regenerated about once every fifteen minutes.

The SCONOx™ catalyst is very susceptible to fouling by sulfur in the flue gas. Sulfur causes the catalyst to become deactivated. The impact of sulfur is minimized by a dedicated sacrificial SCOSOx™ sulfur asorption catalyst upstream of the SCONOx™ catalyst. The SCOSOx™ catalyst is always installed, even on applications firing exclusively pipeline-quality natural gas. The SO_2 is oxidized to SO_3 by the catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SCOSOx™ catalyst is regenerated along with the SCONOx™ catalyst. The resulting byproduct of the SCOSOx™ regeneration is either H_2S (for systems with flue gas temperatures below 500 EF at the SCONOx™ catalyst) or SO_2 (for systems with flue gas temperatures above 500 oF). In the case of an H_2S byproduct, it can be removed from the regeneration gas through a carbon scrubber. In the case of an SO_2 byproduct, the regeneration gas is piped back into the combustion turbine exhaust downstream of the SCONOx™ catalyst. The SO_2 then exits the stack along with the rest of the flue gas. In this case, SO_2 emissions are the same as typically found during natural gas firing.

The SCONOx™ catalyst will require that it be periodically "washed" or "re-coated". The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SCONOx™ catalyst. ABB Alstom Power estimates are that the SCONOx™ catalyst must be washed at least once every 24,000 operating hours. Re-coating consists of removing the catalyst modules from the unit and submerging each module in potassium carbonate solution, which is the active ingredient of the catalyst. The SCONOx™ catalyst will also require washing, but due to limited operating experience with the SCONOx™ catalyst, it is uncertain how often it will be required. However, ABB Alstom Power estimates are that the SCONOx™ catalyst will also require washing every 24,000 hours.

The washing process requires the unit to be shut down for some period of time (estimated to be 3 to 5 days or longer for an F Class turbine) in order to remove, re-coat and replace the SCONOx™ catalyst. In addition to the maintenance costs of the washing, the facility will have the disadvantage of added loss of generation during this period. The expected cycle of washing of the SCONOx™ catalyst (every 24,000 operating hours) will cause additional outages of the facility.

Design considerations for the SCONOx™ system primarily pertain to the need to increase the size of the technology and associated operating equipment from that used in the LM2500 combustion turbine application for use in a G Class 230 MW machine. Mechanical systems including damper and damper bearings are moving parts in the flue gas stream that may present reliability and maintenance problems upon scale up.

Distribution of the regeneration gas is critical for SCONOx™ to achieve the advertised control efficiencies. Testing of the technology at the appropriate size, temperatures and flow rates with the appropriate catalyst volume in place is critical to ensure consistent and reliable emissions control performance.

The SCONOx™ system has been installed and in operation since December 1996 on a General Electric LM2500 at the Federal Plant owned by Sunlaw Cogeneration and is a second generation system. The first generation system operated for ten months on a similar unit owned by Sunlaw before it was removed from service due to poor regeneration gas distribution. Results from this operating system are promising, with recorded NO_x emission levels at 2 ppm and below.

SCONOx™ was recently installed on a 5 MW Solar Taurus 60 combustion turbine cogeneration unit at the biotech facility at the Genetics Institute in Massachusetts. This SCONOx™ application has been operating at an average NOx emission rate of less than 1 ppm and undetectable CO emission rates during the unit's commissioning.

PG&E Generating has received an "Authority to Construct" permit which includes the ability to install a SCONOx™system on one of four ABB KA-24 machines at their La Paloma Power Generating Project near Bakersfield, California. It should be noted that in proposing SCONOx™ for the La Paloma project, PG&E Generating stated that this was for the expressed purpose of demonstrating the ability of this technology to achieve in practice, on a large combustion turbine similar in size to a General Electric Frame 7F, the NOx emission levels that have been proposed. The permitted NOx emission rate for this project is 2.5 ppmvd. Discussions with ABB Alstom Power reveal that PG&E Generating does not have a contractual agreement to install the SCONOx™ system at this plant and that all of the units associated with this project will be equipped with SCR for NOx controls.

PG&E Generating has also proposed to utilize SCONOx™ in conjunction with the recently submitted permit application for the 510 MW Otay Mesa power plant proposed to be sited in San Diego County, California. The Otay Mesa project is in the early stages of permitting. The proposed NOx emission rate for this project is 2.0 ppmvd. Conversations with ABB Alstom Power reveal that PG&E Generating does not, to date, have a signed contractual agreement to install SCONOx™ on this project.

Although SCONOx™ may be considered to have been demonstrated in practice for the class of source comprising the LM2500 and smaller combustion turbines, transfer of this technology to the class of source comprised by G Class machines and similarly sized machines is not technically feasible at this time and has not been demonstrated in this class of source. The LM2500 and small class of combustion turbines are not and cannot be considered to be included in the same class of source because of the large differences in size and exhaust gas flow rate, among other characteristics.

Any claim that the EPA has declared SCONOx™ to be LAER is misleading since the EPA does not certify technologies as LAER, but only the emission rate to be achieved. The EPA has previously explained this point to Goal Line in written communication. Other technologies that are able to reach this level of performance can also be considered LAER, therefore, the LAER designation is not limited to SCONOx™

The SCONOx™ system imposes back pressure on the combustion turbine, reducing output and efficiency. Additionally, SCONOx™ uses natural gas in the regeneration process thus reducing plant fuel efficiency. Furthermore, SCONOx™ consumes large amounts of steam as a carrier gas, thereby reducing the net generating output of the plant.

In addition to the items cited above, discussions with ABB Alstom Power, the sole licensee of SCONOx™ for large combustion turbines, reveal that the technology has not been installed on F or G Class machines, no NOx emission control efficiencies of any kind have been demonstrated on a General Electric 7FA, Siemens/Westinghouse 501 FD or Siemens/Westinghouse 501G; no SCONOx™ systems have been sold for installation on General Electric 7FA, Siemens/Westinghouse 501 FD or Siemens/Westinghouse 501G combustion turbines; and finally SCONOx™ has not been demonstrated to achieve any level of performance, BACT or LAER, in applications with large combustion turbines such as the combustion turbines proposed for the Hot Spring Power Project. In summary, SCONO$_X$ technology has not been demonstrated in practice for the size of turbines proposed for the Hot Spring Power Project; therefore this technology does not currently represent BACT.

Control Alternatives Hierarchy

The following table ranks the technically feasible control alternatives according to the level of control. The table ranks the control alternatives from highest level of control to lowest level of control, i.e, “top down.”

NOx Control Alternatives Hierarchy		
Control Alternatives	**NOx Concentration after Control (ppmvd @ 15% O$_2$)**	**NOx Annual Emission Rate after Control (tpy)**
DLN w/ SCR	2.0	84.17
DLN w/ SCR	3.5	147.30
DLN w/o SCR	25.47	1,058.67

Energy Impacts

1) <u>Selective Catalytic Reduction (SCR)-3.5 ppmvd @ 15% O$_2$</u>

The catalyst used in the SCR system results in an increase in the back pressure in the turbine exhaust and a subsequent performance loss (pressure de-rate) in turbine output. The use of this SCR system has the potential to reduce the annual electrical output up to 8,000 MW compared to no controls.

2) Selective Catalytic Reduction (SCR)-2.0 ppmvd @ 15% O_2

The increased catalyst surface area in this SCR system results in an increased pressure drop across the catalyst bed, therefore, increasing the back pressure on the combustion turbine from the exhaust. The back pressure will result in subsequent performance loss (pressure de-rate) in turbine output. The potential incremental loss (i.e. from 3.5 ppmvd to 2.0 ppmvd) in annual electrical production has been estimated at 500 MW.

Cost/Economic Impacts

Incremental cost effectiveness, in terms of dollars per ton of NO_X emission reduction, is a key criteria used to assess the economic feasibility of a control alternative. By expressing costs in terms of the amount of emission reduction achieved, comparisons can be performed.

Incremental cost effectiveness is calculated as the annualized cost of the NO_X control option being considered divided by the baseline minus the control option emissions rate, as shown by the following formula:

$$\text{Cost Effectiveness (\$/ton removed)} = \frac{\text{NO}_X\text{ control option annualized cost}}{\text{Base case emissions rate - NO}_X\text{ Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr,) and emission rates are calculated in tons per year (tpy). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of NO_X removed.

The annualized costs have been estimated in accordance with the Office of Air Quality Planning and Standards (OAQPS), Control Cost Manual, (EPA ,1996). The basis for the equipment cost estimates have been derived from the equipment vendors or similar projects. The other direct and indirect operating costs have been estimated based upon guidance from the Control Cost Manual and the Office of Air Quality Planning and Standards, Alternate Control Techniques Document - NO_X Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993.

The base case control is DLN technology with no post combustion control for a NOx concentration of 25.47 ppmvd, corrected to 15% oxygen. The proposed control for the turbine is DLN technology coupled with an SCR to achieve a NOx concentration of 3.5 ppmvd, corrected to 15% oxygen. The top tier alternative control technology for NOx is DLN technology coupled with an SCR to achieve a NOx concentration of 2.0 ppmvd, corrected to 15% oxygen. The proposed and alternative control cases have been compared to the base case to determine the cost effectiveness. As discussed previously, an SCR may not be able to achieve the lower NOx concentration for the G class machine. Accordingly, for the purposes of this analysis, the costs for the alternate control option have been extrapolated from an SCR capable of achieving 3.0 ppmvd corrected to 15% oxygen for the Siemens/Westinghouse 501G; therefore, the estimated cost-effectiveness would be conservative if, in fact, an alternate technology would be required to meet the lower NOx concentrations.
The estimated direct and indirect operating costs for the implementation of SCR technology for the control alternatives for NOx control from the Hot Spring Power Project have been identified in the application. The table below summarizes the results of the cost analysis.

NOx Control Cost Analysis Summary

Control Alternatives	NOx Concentration after Control (ppmvd @ 15% O_2)	NOx Annual Emission Rate after Control (tpy)	Cost Effectiveness over Base Control ($/ton removed)
DLN w/ SCR	2.0	84.17	$5,812
DLN w/ SCR	3.5	147.30	$5,108
DLN w/o SCR	25.47	1,058.67	$0

Environmental Impacts

1) Selective Catalytic Reduction (SCR) - 3.5 ppmvd @ 15% O_2

The use of ammonia in the SCR process presents several potential environmental impacts. Anhydrous ammonia is on the EPA list of extremely hazardous substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). In addition, anhydrous ammonia is considered a disaster chemical by the EPA.

There are not as many environmental impact considerations associated with this alternative as there are with anhydrous ammonia. Aqueous ammonia is not listed as an extremely hazardous compound pursuant to Section 302 of SARA Title III. Additionally, the operations utilizing aqueous ammonia are exempt from Occupational Safety and Health Administration's (OSHA's) Process Safety Management rules pursuant to 29 CFR 1910.119.

The accidental release of ammonia into the environment is also of concern. This is a major concern with the use of anhydrous ammonia. The adverse environmental impacts from an accidental release will be tempered with the use of aqueous ammonia. As stated previously, Hot Spring Power Company, L.L.C. proposes to utilize a 28 wt% aqueous ammonia solution.

Releases of aqueous ammonia to the atmosphere may occur in several ways, including unreacted ammonia going through the stack, known as ammonia slip. The ammonia slip is estimated to be approximately 10 ppm for SCR systems.

SCR applications also generate a solid waste in the form of spent catalyst that requires treatment and disposal. As a result, disposal of spent catalyst would pose additional economic costs and potential environmental liabilities for Hot Spring Power Company, L.L.C.

2) Selective Catalytic Reduction (SCR) - 2.0 ppmvd @ 15% O_2

As this control alternative is similar to the SCR system discussed above, the environmental issues would be similar. The difference between the environmental impacts of two alternatives would be in the volume of waste generated. As more catalyst is required to achieve reduced NO_X concentrations, more spent catalyst is generated during the replacement operations. The replacement times are expected to be comparable.

Conclusion

It is evident from the analysis that the implementation of DLN technology, coupled with an SCR capable of achieving a combustion turbine exhaust gas NO_x concentration of 2.0 ppmvd, corrected to 15% oxygen, provides for a lower emission rate than the proposed and base case control technology. As discussed previously, DLN technology coupled with an SCR may not be capable of achieving NO_X concentrations of 2.0 ppmvd corrected to 15% oxygen for the G class combustion turbine. There have been no permits issued for G class turbines down to this NO_X level. The project has ascertained vendor guarantees that approach NO_X concentrations of 3.5 ppmvd corrected to 15% oxygen with the use of an SCR. The lower emission rate has been demonstrated for F class combustion turbines. Consequently, the control technology proposed for the Hot Spring Power Project is the implementation of DLN technology coupled with an SCR capable of achieving a combustion turbine exhaust gas NOx concentration of 3.5 ppmvd, corrected to 15% oxygen. As the proposed control methodology is to meet BACT and not LAER, a less stringent technology may be implemented if the most stringent technology is not achievable based on an objective analysis of the potential energy, economic, and environmental impacts.

As discussed previously, the use of an SCR results in an increase in the back pressure of the turbine exhaust. The resultant back pressure corresponds in a subsequent performance loss in available turbine output. Therefore, use of an SCR would require additional natural gas input to maintain the same available turbine output as a turbine using no controls. Based upon the engineering design of an SCR capable of achieving a combustion turbine exhaust gas NOx concentration of 3.5 ppmvd, corrected to 15% oxygen this alternative would result in decreased turbine output when compared to the base control technology.

The environmental impacts for the two controls are relatively the same in that both would utilize aqueous ammonia and generate a spent catalyst waste during catalyst replacement. However, the more stringent control technology, DLN technology coupled with an SCR capable of achieving a combustion turbine exhaust gas NOx concentration of 2.0 ppmvd, corrected to 15% oxygen, would require more aqueous ammonia. Consequently, more ammonia slip emissions would be increased through the stacks. Additionally, more spent catalyst would be generated for the more stringent control technology over its lifetime; therefore, the implementation of the base control technology would result in a lesser environmental impact compared to the more stringent technology.

Cost effectiveness is the criterion used to assess cost or economic impacts of the control technologies identified for minimizing NOx emissions. The cost effectiveness calculations utilized for this BACT analysis have been conducted on an average basis. Average cost effectiveness (total annualized costs of control divided by annual emissions reductions, or the difference between the baseline emission rate and the controlled emission rate) has been estimated comparing the proposed BACT controls and the alternative NOx control against the base case control (i.e. no post-combustion control equipment).

In general, study cost estimates used in BACT are typically accurate to " 20 to 30 percent. USEPA's draft " New Source Review Workshop Manual - Prevention of Significant Deterioration, October 1990" states that cost options that are within this " 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options. From the NOx Control Cost Analysis Summary table, the cost per ton of pollutant removed for the alternative control technology (i.e. SCR capable of achieving a NOx concentration of 2.0 ppmvd, corrected to 15% oxygen) is approximately 14% higher than the proposed BACT controls (i.e. SCR capable of achieving a NOx concentration of 3.5 ppmvd, corrected to 15%

oxygen). Based upon the average cost effectiveness evaluation, the impacts of the alternative control technology are indistinguishable from the proposed BACT controls.

In the draft document USEPA recommends that the incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option. Incremental costs of the alternative control technology compared to the proposed BACT control have been estimated at approximately $15,976 per ton of NO_X removed. Typical market value across the country for NO_X emission credits ranges from $3,500 - $5,000 per ton. Thus, the impacts of the control alternative technology as BACT are economically unfeasible when compared to the proposed BACT controls.

The results of the top down BACT review identified three potential control alternatives for minimizing emissions of NO_X from the combustion turbines. The proposed control technology capable of achieving a NO_X concentration of 3.5 ppmvd, corrected to 15% oxygen has been identified as a viable alternative based on the evaluation of energy, economic, and environmental impacts. Therefore, the Hot Spring Power Project is proposing that the implementation of DLN technology coupled with an
SCR capable of achieving a combustion turbine exhaust gas NO_X concentration of 3.5 ppmvd, corrected to 15% oxygen, be considered the BACT for the combustion turbines and duct fired HRSGs.

BACT for PM_{10} - CT/ HRSG/ Duct Burner

Overview

PM emissions mainly result from combustion of contaminants, hydrocarbons and sulfur compounds in the natural gas. The formation of PM emissions result from carryover of noncombustible trace constituents in the fuel, lubricating oil, and from products of incomplete combustion. Emission of PM from natural gas-fired reciprocating engines are generally minimal and comprise fine filterable and condensible PM. Increased PM emissions may result from poor air-to-fuel mixing or maintenance problems.

Technical Feasibility

As the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that PM control devices are not typically installed on combustion turbines and that the cost of installing a PM control device is prohibitive. Performance standards for particulate control of stationary combustion turbines were, therefore, not proposed or promulgated.

Available technologies used for controlling PM include the following:

- Centrifugal collectors;
- Electrostatic precipitators (ESPs);
- Fabric filters or baghouses; and
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large (> 10 microns) size particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95% for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) As the gas passes through the fabric filter, accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot. Collection efficiencies are on the order of 99% for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in the throat section, the large column of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90% for particles smaller than 2.5 microns in size.

Available technologies chosen have not been demonstrated on natural gas fired combustion turbines. Therefore, Hot Spring Power Company, L.L.C. proposes no PM_{10} emission controls except the firing of clean pipeline natural gas for the combustion turbines and duct fired HRSGs. The permittee proposes a BACT emission limit of 0.013 lb PM10/MM Btu. This is acceptable as BACT.

BACT for PM_{10} - Cooling Tower

Overview

Wet cooling towers provide direct contact between the cooling water and the air passing through the tower. Some of the liquid water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Particulate matter is generated when the drift droplets evaporate and leave fine particulate matter formed by the crystallization of dissolved solids.

The magnitude of drift loss is influenced by the number and the size of the droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and other interrelated factors. Tower maintenance and operation levels also can influence the formation of drift droplets. For example, excessive water flow, excessive air flow, and water bypassing the tower drift eliminators can promote and/or increase drift emissions.

As the drift droplets generally contain the same chemical impurities as the water circulating through the tower, these impurities can be converted to airborne emissions. Large drift droplets settle out of the tower exhaust air stream and deposit near the tower. This process can lead to wetting, icing, salt deposition, and related problems such as damage to equipment or to vegetation. Other drift droplets may evaporate before being deposited in the area surrounding the tower, and they also can produce PM_{10} emissions. PM_{10} is generated when the drift droplets evaporate and leave fine particulate matter formed by crystallization of dissolved solids. Dissolved solids found in cooling tower drift can consist of mineral matter, chemicals for corrosion inhibition, etc.

To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient. Drift eliminators may include various materials, such as ceramics, fiber reinforced cement, fiberglass, metal, plastic, wood installed or formed in closely spaced slats, sheets, honeycomb assemblies, or tiles. The material may include other features, such as corrugations and water removal channels, to enhance drift removal further.

A review of similar recently permitted facilities has identified drift eliminators as the potentially applicable control technology alternative BACT for PM_{10}. A typical drift eliminator can achieve a drift factor of 0.005% while high efficiency drift eliminators can achieve a drift factor of up to

0.0005%. Hot Spring Power Company, L.L.C. is proposing the installation of a high efficiency drift eliminator of 0.0005% drift factor as the control technology for PM_{10}.

Technical Feasibility

1) Typical Drift Eliminator - 0.005% Drift Factor

Typical drift eliminator designs embody an array of narrow channels in the vertical flow direction of the tower, which force the air to flow in a direction inclined to the vertical. The efficiency of the drift eliminator is governed by the channel orientation and geometry and the air flow rate, as well as the droplet size distribution. A typical drift eliminator is considered a technically feasible control technology for the control of PM_{10} emissions from wet cooling towers. The PM_{10} emissions of a cooling tower with a drift eliminator of 0.005% drift factor is 8.07 lbs/hr.

2) High Efficiency Drift Eliminator - 0.0005% Drift Factor

As previously mentioned, the efficiency of the drift eliminator is governed by the orientation angle of the channels, the air flow rate, and the size of the droplets. In general, drift factor is found to increase at a channel inclination angle of 45% and as the air flow rate increases. The enhancement in the drift factor is a result of the increase in the total mass flow through the eliminator space. A high efficiency drift eliminator is considered a technically feasible control technology for the control of PM_{10} emissions from wet cooling towers. The PM_{10} emissions of a cooling tower with a drift eliminator of 0.0005% drift factor is 0.81 lbs/hr.

Control Alternative Hierarchy

The following table demonstrates the technically feasible control alternatives according to the level of control from the highest to the lowest level of control.

PM_{10} Control Alternatives Hierarchy

Control Alternatives	PM_{10} Maximum Hourly Emission after Control (lbs/hr)	PM_{10} Annual Emission Rate after Control (tpy)
0.005% Drift Eliminator	8.07	35.34
0.0005% Drift Eliminator	0.81	3.53

Energy Impacts

1) Typical Drift Eliminator - 0.005% Drift Factor

The drift eliminators used in cooling towers are based on inertial separation caused by direction changes while passing through the eliminators, which requires no additional energy. Therefore, there is little to no energy impact.

2) High Efficiency Drift Eliminator - 0.0005% Drift Factor

To achieve a drift rate of 0.0005% additional layers of high efficiency drift eliminators will be installed. There is little to no energy impact.

Cost/Economic Impacts

Cost effectiveness, in terms of dollars per ton of PM emission reduction, is a key criteria used to assess the economic feasibility of a control alternative. By expressing costs in terms of the amount of emission reduction achieved, comparisons can be performed.

Cost effectiveness is calculated as the annualized cost of the PM control option being considered divided by the baseline minus the control option emissions rate, as shown by the following formula:

$$\text{Cost Effectiveness (\$/ton removed)} = \frac{\text{Control option annualized cost}}{\text{Base case emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr), and emissions rates are calculated in tons per year (tpy). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of PM removed.

The annualized costs have been estimated in accordance with the Office of Air Quality Planning and Standards (OAQPS), Control Cost Manual, (EPA, 1996). The basis for the equipment cost estimates have been derived from either equipment vendors or similar projects.

The proposed control for the cooling tower is the installation and operation of a high efficiency drift eliminator capable of achieving a drift factor of 0.0005%. The base control technology is a drift eliminator capable of achieving a drift factor of 0.005%. The proposed control technology has been compared to the base case to determine the cost effectiveness.

The differential cost between the base case and proposed case are attributed to additional capital/equipment costs. There is little to no difference in operating or maintenance costs; therefore, additional costs other than the capital costs have not been evaluated.

The additional incremental cost for the installation of the high efficiency drift eliminator is $93,940. The table below summarizes the results of the cost analysis.

PM Control Cost Analysis Summary

Control Alternatives	Maximum hourly PM Emissions Post Control (lbs/hr)	Annual PM Emission Post Control (tpy)	Incremental Cost Effectiveness over Base Case ($/ton Removed)
0.0005% Drift Eliminator	0.81	3.53	$2,957
0.005% Drift Eliminator	8.07	35.3	$0

Environmental Impacts

The installation and operation of either the 0.005% or 0.0005% drift eliminator as control technology for the reduction of drift droplets have no significant environmental impacts.

Conclusions

EPA's compilation of emission factors for air emission sources (AP-42) has identified the drift eliminator as a feasible control technology for minimizing emissions of PM_{10} from the cooling tower. Hot Spring Power Project has proposed a high efficiency drift eliminator capable of achieving 0.0005% drift factor as the control technology and a drift eliminator capable of achieving 0.005% drift factor as the base control technology.

A comparison of the base control technology to the proposed control technology identifies little to no differences in term of energy requirements and cost/economics impacts. The high efficiency drift eliminator, however, offers 10 times the drift entrainment reduction. No additional energy is required for the high efficiency drift eliminator, and the increment cost effectiveness over base case per ton of PM_{10} removed is less than $3,000. There are little or no environmental impacts associated with either one of the control technology options under evaluation.

In considering the relatively economical incremental costs associated with the installation and operation of the high efficiency drift eliminator along with its capability to achieve 10 times the drift droplet removal efficiency of the typical drift eliminator, Hot Spring Power Project is proposing the high efficiency drift eliminator (0.0005% drift factor) as the BACT control technology of PM emissions from the cooling tower.

Summary of BACT Determinations

The following table summarized each BACT determination and limits made for this facility:

Pollutant	SN-01 and SN-02	SN-04 through SN-15
NO_x	Dry low-NO_x and SCR (3.5 ppmvd @ 15% O_2 24 hour average)	NA
CO	CO/ VOC Oxidation Catalyst (12 ppmvd @ 15% O_2 24 hour average)	NA
VOC	CO/ VOC Oxidation Catalyst (4.0 ppmvd @ 15% O_2)	NA
PM_{10}	Good operating practice (0.013 lb/MMBtu)	high efficiency drift eliminator (0.81 lb/hr; 0.0005% drift factor)

Each BACT determination and corresponding emission rates/ level is consistent with that of similar units found in the RBLC and is consistent with other similar permitted sources in Arkansas.

Air Quality Analysis

As part of the PSD permitting procedure a new source must perform an air quality analysis to assess impact to local NAAQS and to evaluate the increment consumption. The first step in this review is to evaluate the impact of pollutants that will increase by PSD significant levels. In this case, the pollutants evaluated are PM_{10}, NO_2, and CO. SCREEN3 dispersion modeling was used for various turbine load scenarios to determine worse-case operating rates for the pollutants screened. The pollutants were then modeled at these worse case conditions using ISCST3 modeling procedures. The dispersion modeling shows that these pollutants do not exceed PSD significant impact levels; therefore, multi-source refined modeling is not necessary to satisfy PSD requirements. The following table summarizes the maximum concentration predicted by dispersion modeling:

Pollutant		PSD Modeling Significant Impact	Impact from HS Power Project
PM_{10}	annual	1	0.275
	24-hour	5	2.88
NO_2	annual	1	0.359
CO	8-hour	500	23.8
	1-hour	2000	190.5

Ozone formation near the facility could result from the emissions of NO_x and VOCs. Scheffe Screening Tables are often used in this case as an initial step to estimating levels of ozone formation. In this case, the rural based ozone impact predicted by Scheffe tables is a negligible level because of the relatively low emission rates involved. It can therefore be assumed that the facility will have no noticeable impact on ozone formation.

Additional Impact Analysis

An additional impacts analysis is completed based on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the facility's area of impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation impacts, and (3) visibility impairment.

Growth

The growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from the associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. The number of new permanent jobs created by the project is expected to be approximately 25 after construction. To the extent possible, these jobs will likely be filled from the local labor pool. Accordingly, negligible new growth is anticipated as a result of the new facility.

Soils and Vegetation Analysis

The soils and vegetation analysis is based on an inventory of soils and vegetation types with commercial or recreational value found in the impact area. The impact area is defined as the maximum distance from the facility at which ambient impacts from the source exceed the PSD modeling significance level (MSL). Because the impacts associated with the operation of the proposed facility are below all applicable PSD MSL, no impact area exists that is associated with the project. Impacts to soils and vegetation resulting from operation of the proposed facility are thus expected to be negligible.

Visibility Impairment Analysis

A visibility impairment analysis is required to assess visibility impacts in Class I areas located within 100 kilometers of the proposed facility. There are no Class I areas within 100 kilometers of the proposed facility, however Caney Creek Wilderness Area is located approximately 111 km from the proposed site. Visibility was evaluated for Caney Creek using the Level 1 procedures described in the EPA Guidance document *Workbook for Plume Visual Impact Screening and Analysis* (EPA 1980). No adverse impacts were determined to occur from this project. Furthermore, visibility impacts are expected to be negligible because impacts of all modeled pollutants are below the MSL and, by definition, insignificant.

Non-Criteria Pollutants

An analysis was conducted to determine if emission rates of non-criteria pollutants associated with the facility trigger dispersion modeling requirements for any specific non-criteria pollutants. The analysis was conducted according to the Non-Criteria Pollutant Control Strategy. Contaminants with emission rates less than the Presumptively Acceptable Emission Rate

(PAER) are exempt from dispersion modeling. Emission rates and PAER's for non-criteria pollutants associated with the facility are presented in the following table:

HAP (or Ammonia)	Emission Rate (lb/hr)	TLV (mg/m^3)	PAER* (lb/hr)	Modeling Required**
ammonia	91.44	17.4	1.91	Y
ammonium sulfate	4.36	0.5	0.055	Y
<u>VHAPS</u>				
1,3-butadiene	0.02	4.4	0.484	N
acetaldehyde	0.08	45	4.95	N
acrolein	0.02	0.23	0.025	N
benzene	0.02	32	3.52	N
formaldehyde	0.14	1.5	0.165	N
n-hexane	0.70	176	19.36	N
naphthalene	0.02	52.4	5.76	N
propylene oxide	0.06	48	5.28	N
toluene	0.08	188	20.68	N
xylene	0.02	434	47.74	N
PAH***	0.02	52.4	5.76	N

* PAER is the TLV of the HAP X 0.11
** If the proposed lb/hr is less than the PAER, then no further modeling is required.
*** Naphthalene used as representative PAH

This analysis shows that all non-criteria pollutants passed the first level of modeling except ammonia and ammonium sulfate. Consequently, these two species are modeled with SCREEN3 dispersion methods to show compliance with the Presumptively Acceptable Impact Level (PAIL). PAIL is the maximum ambient 24-hour average concentration, for Hazardous Air Pollutants (HAPs), less than or equal to 1/100th of the Threshold Limit Value (TLV) or an acceptable concentration that has been established by the Department for each substance emitted. The ambient concentration resulting from the proposed emission rate of a substance is determined by using atmospheric dispersion models to obtain the maximum ambient, ground level concentration expressed as a 24-hour average.

HAP (or Ammonia)	Emission Rate (lb/hr)	TLV (mg/m^3)	PAIL (Fg/m^3)	SCREEN3 Result	Pass
ammonia	91.44	17.4	173	2.396	Y
ammonium sulfate	4.36	0.5	5	0.114	Y

Emissions Summary

The following table is a summary of emissions from the facility. Specific conditions and emissions for each source can be found starting on the page cross referenced in the table. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
	Total Allowable Emissions	PM	80.4	240.2	NA
		PM_{10}	80.4	240.2	
		SO_2	9.6	13.2	
		VOC	34.5	63.4	
		CO	180.5	615.0	
		NO_x	86.5	294.6	
	HAPs*	acetaldehyde	0.08	0.28	
		acrolein	0.02	0.10	
		benzene	0.02	0.06	
		1,3 butadiene	0.02	0.02	
		formaldehyde	0.14	0.48	
		n-hexane	0.70	1.60	
		naphthalene	0.02	0.02	
		PAH (polycyclic aromatics)	0.02	0.02	
		proylene oxide	0.06	0.20	
		toluene	0.08	0.30	
		xylene	0.02	0.10	
	Air Contaminants **	ammonia	91.44	311.6	
		ammonium sulfate	4.36	5.96	
01	Siemens/Westinghouse 501G and associated Duct Burner			<u>total tpy SN-01 and SN-02</u>	48
		PM	39.8		
		PM_{10}	39.8	236.6	
		SO_2	4.8	236.6	
		VOC	17.3	13.2	
		CO	90.3	63.4	
		NO_x	43.3	615.0	
		acetaldehyde	0.04	294.6	

EMISSION SUMMARY

Source No.	Description	Pollutant	Emission Rates lb/hr	Emission Rates tpy	Cross Reference Page
		acrolein	0.01	0.28	
		benzene	0.01	0.10	
		1,3 butadiene	0.01	0.06	
		formaldehyde	0.07	0.02	
		n-hexane	0.35	0.48	
		naphthalene	0.01	1.60	
		PAH (polycyclic aromatics)	0.01	0.02 0.02	
		proylene oxide	0.03		
		toluene	0.04	0.20	
		xylene	0.01	0.30	
		ammonia	45.8	0.10	
		ammonium sulfate	2.19	311.6 5.96	
02	Siemens/Westinghouse 501G and associated Duct Burner	PM	39.8	See combined SN-01 and SN-02 tpy totals above	48
		PM$_{10}$	39.8		
		SO$_2$	4.8		
		VOC	17.3		
		CO	90.3		
		NO$_x$	43.3		
		acetaldehyde	0.04		
		acrolein	0.01		
		benzene	0.01		
		1,3 butadiene	0.01		
		formaldehyde	0.07		
		n-hexane	0.35		
		naphthalene	0.01		
		PAH (polycyclic aromatics)	0.01		
		proylene oxide	0.03		
		toluene	0.04		
		xylene	0.01		
		ammonia	45.8		
		ammonium sulfate	2.19		
04-15	Cooling Tower Cells 1-12	PM	0.9	3.6	61
		PM$_{10}$	0.9	3.6	

* Each HAP is included in the VOC totals.

** Neither one of the two Air Contaminants is a VOC.

SECTION III: PERMIT HISTORY

Permit #1987-AOP-R0 is the initial permit for this facility.

SECTION IV: EMISSION UNIT INFORMATION

SN-01 and SN-02

Two CT/ HRSG/ Duct Burner Units

Source Description

The facility incorporates a two-on-one configuration - two Siemens/Westinghouse 501G combustion turbines fired HRSGs and one steam turbine - to provide for a nominal generating capacity of 700 MW to a maximum capacity of 815 MW with the firing of the duct burners. The combustion turbines and duct burners are fired solely by natural gas. Normal operation consists of both combustion turbine and HRSG units operating at base load without supplemental firing from duct burners. The units are expected to operate continuously (8,760 hours per year), except for maintenance and repair activities or during periods of low electrical demand. The duct burners are fired to meet peak electrical demands at a maximum of 2,500 hours per year.

The turbine has a total heat consumption rate of approximately 2,200 MMBtu/hour, but this varies with ambient conditions and operational load. The duct burners have a maximum firing rate of 600 MMBtu/hour, high heating value (HHV).

Good combustion controls along with natural gas firing are employed to reduce emissions of SO_2 and PM_{10}. An oxidation catalyst is used to reduce annual VOC and CO concentrations in the stack to 4.0 parts per million by volume dry (ppmvd) and 12.0 ppmvd, respectively corrected to 15% oxygen, while operating at ambient conditions as base load operations. Dry low-NO_x (DLN) technology, coupled with a selective catalytic reduction (SCR) unit, is used to minimize combustion turbine and duct burner NO_x emissions to 3.5 ppmvd, corrected to 15% oxygen, for natural gas firing. The operation of the SCR involves the injection of aqueous ammonia into the exhaust gas stream ahead of a catalyst bed.

Specific Conditions

Particulate Matter and Opacity

1. Pursuant to §19.501 and §19.901 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation 19) effective February 15, 1999 and 40 CFR Part 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 or SN-02. Initial compliance with this condition shall be demonstrated by the initial testing requirements of Specific Condition 5. Ongoing compliance shall be demonstrated by permitting at maximum rates and the exclusive use of natural gas.

The hourly emission rates set forth in the following table were based on a worst-case scenario.

Pollutant	lb/hr	Averaging Period
PM	39.8	Per EPA Reference Method 5
PM_{10}	39.8	Per EPA Reference Method 5

2. Pursuant to §19.501, §19.901, 40 CFR 52, Subpart E, the permittee shall not exceed the annual emission rates set forth in the following table at SN-01 and SN-02 combined.

Initial compliance with the annual emission rates set forth in the following table shall be demonstrated by the initial performance test of the CT/HRSG/duct burner stacks for PM/PM_{10}.
Continuing compliance with the annual emission rates shall be demonstrated by permitting these sources at maximum annual rates. Maximum annual emission rates are based on an average ambient temperature and limited annual duct-burner firing.

Pollutant	tons per consecutive 12 months
PM	236.6
PM_{10}	236.6

3. Pursuant to §19.901and 40 CFR 52, Subpart E, the permittee shall comply with the following BACT determinations for SN-01 and SN-02. Compliance with the emission levels set forth in the following table shall be demonstrated by the performance testing requirements of Specific Condition 5.

Pollutant	BACT Determination		
PM_{10}	good combustion practices and clean fuels	0.013 lb/MM Btu	3-hr avg.

4. Pursuant to §18.501 and A.C.A., the permittee shall not cause to be discharged to the atmosphere from SN-01 or SN-02 stack gases which exhibit greater than 5% opacity averaged over a six minute period. Compliance with this opacity limit shall be demonstrated by the use of natural gas as the only permitted fuel.

5. Pursuant to §19.702, §19.901, and 40 CFR 52 Subpart E, the permittee shall perform an initial stack test on one of the two of SN-01 or SN-02 to demonstrate compliance with the limits specified in Specific Conditions 1 and 3. Testing shall be performed in accordance with Plantwide Condition 3 and EPA Reference Methods 5 and 202 as found in 40 CFR Part 60 Appendix A. Testing shall be performed in combined cycle mode at greater than or equal to 90% of the maximum operating load.

Sulfur Dioxide

6. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 or SN-02. Compliance with this condition will be demonstrated by the monitoring requirements of Specific Condition 8.

   The hourly emission rates set forth in the following table were based on a worst-case scenario.

Pollutant	lb/hr	Averaging Period
SO_2	4.8	Per Appendix A

7. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 and SN-02 combined. Compliance shall be based on compliance with Specific Condition 8.

Pollutant	tons per consecutive twelve months
SO_2	13.2

8. Pursuant to §19.703, NSPS Subpart GG, 40 CFR Part 75 Subpart B, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the monitoring requirements relative to SO_2 emissions from the CT/HRSG/duct burner exhausts shall be as follows:

   A. The permittee shall monitor the natural gas fuel sulfur content using the custom fuel monitoring schedule outlined in Appendix A of this permit in order to satisfy fuel bound sulfur monitoring requirements of NSPS Subpart GG.

   B. The permittee shall conduct SO_2 emissions monitoring procedures in accordance with, Appendix D of 40 CFR Part 75. These procedures shall include monitoring the fuel sulfur content of the fuel rounded to the nearest 0.1 grains per 100 SCF. Alternative procedures may include, measuring pipeline natural gas fuel flow rate using an in-line fuel flow meter, determining the gross calorific value of the pipeline natural gas at least once per month, and using the default emission rate of 0.0006 pounds of SO_2 per million Btu of heat input.

C. The permittee shall maintain records which demonstrate compliance with 9(A) & (B). Records shall be submitted in accordance with General Provision 7.

Volatile Organic Compounds

9. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 or SN-02. Compliance shall be demonstrated by initial performance tests required by Specific Condition 12.

The hourly emission rates set forth in the following table were based on a worst-case scenario.

Pollutant	lb/hr	Averaging Period
VOC	17.3	3-hour

10. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 and SN-02 combined.

Initial compliance with the annual emission rates set forth in the following table shall be demonstrated by the initial performance test on one of the two of SN-01 or SN-02 for VOC. Continuing compliance with the annual emission rates shall be demonstrated by permitting these sources at maximum annual rates. Maximum annual emission rates are based on an average ambient temperature and limited annual duct-burner firing.

Pollutant	tons per consecutive twelve months
VOC	63.4

11. Pursuant to §19.901and 40 CFR 52, Subpart E, the permittee shall comply with the following BACT determinations for SN-01 and SN-02. Compliance with the emission levels set forth in the following table shall be demonstrated by the performance test of one of the two of SN-01 or SN-02 for VOC.

Pollutant	BACT Determination	
VOC	Catalytic Oxidation	4.0 ppmvd @ 15% O_2

12. Pursuant to §19.702, §19.901, and 40 CFR 52 4.0Subpart E, the permittee shall perform an initial stack test on either one of SN-01 or SN-02 to demonstrate compliance with the limits specified in Specific Conditions 9 and 11. Testing shall be performed in accordance with Plantwide Condition 3 and EPA Reference Method 25A as found in 40 CFR Part 60 Appendix A. Testing shall be performed in combined cycle mode at greater than or equal to 90% of the maximum operating load.

Carbon Monoxide

13. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 or SN-02. Initial compliance shall be demonstrated by initial performance tests required by Specific Condition 16. Ongoing compliance shall be demonstrated by the CO CEMS required by Specific Condition 17.

Pollutant	lb/hr	Averaging Period
CO	90.3	24-hour

14. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 and SN-02 combined. Compliance shall be demonstrated by compliance with Specific Condition 13 and duct burner firing limits.

Pollutant	tons per consecutive twelve months
CO	615.0

15. Pursuant to §19.901and 40 CFR 52, Subpart E, the permittee shall comply with the following BACT determinations for SN-01 and SN-02. Initial compliance with the emission levels set forth in the following table shall be demonstrated by the performance test of one of the two combustion turbine/heat recovery steam generating unit stacks for CO as required by Specific Condition 16. Ongoing compliance shall be demonstrated by operation of CEMS as required by Specific Condition 17.

Pollutant	BACT Determination	
CO	CO oxidation catalyst	12 ppmvd @ 15%O_2 24 hour average

16. Pursuant to §19.702, §19.901, and 40 CFR 52 Subpart E, the permittee shall perform an initial stack test of one of SN-01 or SN-02 to demonstrate compliance with the limits specified in Specific Conditions 13 and 15. Testing shall be performed in accordance with Plantwide Condition 3 and EPA Reference Method 10 as found in 40 CFR Part 60 Appendix A. Testing shall be performed in combined cycle mode at greater than or equal to 90% of the maximum operating load. The permittee shall perform, at minimum, an initial stack test on one of the two CT/HRSG/duct burner exhaust stacks. This requirement may be fulfilled by Specific Condition 17 with the Department's prior approval.

17. Pursuant to §19.703, §19.901, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall install, maintain, and operate a CO CEMS on each CT/HRSG/duct burner exhaust stack. The CEMS shall comply with the Air Divisions "Continuous Emissions Monitoring Systems Conditions." A copy is provided in Appendix B. The CEMS data may be used by the Department for enforcement purposes. The CEMS shall be used to demonstrate compliance with the CO emission limits specified in Specific Conditions 13, 14, and 15.

Nitrogen Oxides

18. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 or SN-02. Initial compliance shall be demonstrated by initial performance tests required by Specific Condition 21. Ongoing compliance shall be demonstrated by the NO_x CEMS required by Specific Condition 22.

Pollutant	lb/hr	Averaging Period
NO_x	43.3	24-hour

19. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-01 and SN-02 combined. Continuing compliance with the annual emission rates shall be demonstrated by permitting these sources at maximum annual rates. Maximum annual emission rates are based on an average ambient temperature and limited annual duct-burner firing.

Pollutant	tons per consecutive twelve months
NO_x	294.6

20. Pursuant to §19.901and 40 CFR 52, Subpart E, the permittee shall comply with the following BACT determinations for SN-01 and SN-02. Initial compliance with the emission levels set forth in the following table shall be demonstrated by the performance one of the two combustion turbine/heat recovery steam generating unit stacks for NO_x. Ongoing compliance shall be demonstrated by the operation of NOx CEMS required by Specific Condition 22.

Pollutant	BACT Determination	
NO_x	low-NO_x combustion/ SCR	3.5 ppmvd @ 15%O_2

21. Pursuant to §19.702, §19.901, and 40 CFR 52 Subpart E, the permittee shall perform an initial stack test on SN-01 or SN-02 to demonstrate compliance with the limits specified in Specific Conditions 18 and 20. Testing shall be performed in accordance with Plantwide Condition 3 and EPA Reference Method 7E as found in 40 CFR Part 60 Appendix A. Testing shall be performed in combined cycle mode at greater than or equal to 90% of the maximum operating load. The permittee shall perform, at minimum, an initial stack test on one of the two CT/HRSG/duct burner exhaust stacks. This requirement may be fulfilled by Specific Condition 22 with the Department's prior approval.

22. Pursuant to §19.703, §19.901, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall install, maintain, and operate a NO_x CEMS on each CT/HRSG/duct burner exhaust stack. The CEMS shall comply with the Air Divisions "Continuous Emissions Monitoring Systems Conditions." A copy is provided in Appendix B. The CEMS data may be used by the Department for enforcement purposes. The CEMS shall be used to demonstrate compliance with Specific Conditions 18, 19, and 20.

Non-criteria Pollutants

23. Pursuant to §18.801 of Regulation 18 and A.C.A., the permittee shall not exceed lb/hr emission rates listed in the following table at SN-01 or SN-02. Initial compliance shall be determined by testing requirements of Specific Condition 29. Ongoing compliance

with emission rates shall be demonstrated by the exclusive use of pipeline quality natural gas and duct burner operating limits.

Pollutant	lb/hr	Averaging Period
<u>Air Contaminants</u>		
ammonia	45.8	per approved test method
ammonium sulfate	2.19	daily
<u>HAPs</u>		
acetaldehyde	0.04	per method 18
acrolein	0.01	‘’
benzene	0.01	
1,3 butadiene	0.01	‘’
formaldehyde	0.07	
n-hexane	0.35	
naphthalene	0.01	‘’
PAH (polycyclic aromatics)	0.01	
proylene oxide	0.03	
toluene	0.04	‘’
xylene	0.01	

24. Pursuant to §18.801 of Regulation 18 and A.C.A., the permittee shall not exceed ton per year emission rates listed in the following table at SN-01 and SN-02 combined. Initial compliance shall be demonstrated by Specific Condition 26 and burning pipeline quality natural gas. Ongoing compliance shall be determined by compliance with and the exclusive use of pipeline quality natural gas and the duct burner operating limits.

Pollutant	tons per consecutive twelve months
<u>Air Contaminants</u>	
ammonia	311.6
ammonium sulfate	5.96
<u>HAPs</u>	
acetaldehyde	0.28
acrolein	0.10
benzene	0.06
1,3 butadiene	0.02
formaldehyde	0.48

Pollutant	tons per consecutive twelve months
n-hexane	1.60
naphthalene	0.02
PAH (polycyclic aromatics)	0.02
proylene oxide	0.20
toluene	0.30
xylene	0.10

25. Pursuant to §18.1002 and A.C.A. within five years of issuance of this permit, the permittee shall conduct a performance test for ammonia (NH_3) at SN-01 and SN-02 to assure compliance with Specific Condition 23 ammonia emission rates and a maximum ammonia emission level of 10 ppmvd at 15% O_2. The permittee shall use Department approved methodology. Testing on the sources shall be performed in combined cycle at greater than or equal to 90% maximum load.

26. Pursuant to §18.1002 and A.C.A., the permittee shall conduct an initial performance test on either of SN-01 or SN-02 using Method 18 for all detectable HAPs concentrations. The test shall be performed while operating in combined cycle at greater than 90% of capacity. At this time the permittee shall also demonstrate that the facility is not a major source for HAPs (i.e. 10 tpy single HAP or 25 tpy total HAPs facility wide). The permittee has the option to test the CT again in simple cycle mode at greater than 90% load in order to demonstrate that the facility (the two CTs alone) is not a major source for HAPs and is therefore not subject to requirements of the Clean Air Act §112(g). Testing shall be performed in accordance with Plantwide Condition 3.

<u>Throughput Limits</u>

27. Pursuant to §18.1004, §19.705, §19.901, A.C.A., and 40 CFR 70.6, each CT/HRSG/duct burner unit may only fire pipeline quality natural gas.

28. Pursuant to §18.1004, §19.705, §19.901, A.C.A., and 40 CFR 70.6, the duct burners at SN-01 and SN-02 shall not operate more than 5,000 hours total between the two over any twelve month period.

29. Pursuant to §18.1004, §19.705, §19.901, A.C.A., and Part 52, the permittee shall maintain monthly records demonstrating compliance with Specific Condition 28.

Records shall be updated by the fifteenth day following the month to which the records pertain. Records must include a twelve month rolling total. Records shall otherwise be submitted to the Department in accordance with General Provision 7.

New Source Performance Standards

30. Each combustion turbine/heat recovery steam generating unit is subject to and shall comply with applicable provisions of 40 CFR Part 60 Subpart A - *General Provisions* and 40 CFR Part 60 Subpart GG - *Standards of Performance for Stationary Gas Turbines* (Included in Appendix C). Applicable provisions of Subpart GG include but are not limited to, the following:

    A. Pursuant to 40 CFR §60.332(a)(1), the permittee shall not exceed a NO_X emission level of 75 ppmvd at 15% oxygen on a dry basis. Compliance shall be demonstrated by compliance with Specific Condition 20.

    B. Pursuant to 40 CFR §60.333(b) the permittee shall not burn any fuel which contains sulfur in excess of 0.8 percent by weight. Compliance with this condition shall be demonstrated by compliance with Specific Condition 9(A).

    C. Pursuant to 40 CFR §60.334(c)(2), the permittee shall report any monitoring period during which the sulfur content of the fuel being fired in the gas turbines exceeds 0.8 percent by weight.

    D. Pursuant to 40 CFR §60.335 and §60.8, initial compliance testing for NO_X and SO_2 is required within 180 days after start-up. Compliance with the SO_2 requirements will be demonstrated by compliance with Specific Condition 9(A).

       The NO_X performance testing shall be conducted in accordance with test methods in 40 CFR Part 60 Appendix A or alternative approved methods. The testing shall be conducted at four points in the normal operating range of the turbines including the minimum point in the range and at the full load. Compliance with these NO_x performance testing requirements may be waived pending EPA approval of the use of CEMS required by Specific Condition 22 to demonstrate compliance with the NO_x standard.

31. Pursuant to §19.304, and 40 CFR Part 60, Subpart Da, the Duct Burners in the CT/HRSG system (SN-01 through 04) shall comply with all applicable provisions of 40 CFR Part 60, Subpart A - General Provisions and Subpart Da - *Standards of Performance for Electric Utility Steam Generating Units*. A copy of Subpart Da is provided in Appendix

D of this permit. Applicable provisions of Subpart Da include, but are not limited to the following:

A. Pursuant to §60.42(a)(a), no gases shall be discharged into the atmosphere which contain particulate matter in excess of 0.03 lb/million Btu heat input.

B. Pursuant to §60.42(a)(b), no gases shall be discharged into the atmosphere which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour or not more than 27 percent opacity.

C. Pursuant to §60.43(a)(b) and (g), no gases shall be discharged into the atmosphere which contain sulfur dioxide in excess of 0.20 lb/million Btu heat input based on a 30-day rolling average. Compliance shall be demonstrated by requirements of Specific Condition 9(A) and (B).

D. Pursuant to §60.44(a)(d)(1), no gases shall be discharged into the atmosphere which contain nitrogen oxides in excess of 1.6 lb/megawatt-hour gross energy output based on a 30-day rolling average. The nitrogen oxides emission rate from the duct burner component of the combined cycle system shall be calculated by subtracting the nitrogen oxides emission rate measured for the unfired duct burner case from the nitrogen oxides emission rate measured for the fired duct burner case.

E. Pursuant to §60.46(a)(c), the particulate matter and nitrogen oxide emission standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards apply at all times except during periods of startup and shutdown.

F. Pursuant to §60.46(a)(e), compliance with the sulfur dioxide and nitrogen oxide emission limitations is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day average emission rate for both sulfur dioxide and nitrogen oxides are calculated to show compliance with the standards.

G. Pursuant to §60.46(a)(i), nitrogen oxide emissions shall be calculated by multiplying the average hourly NO_x concentration by the average hourly flow rate and divided by the average hourly gross heat rate or other method approved by the administrator. (See Appendix D.)

H. Pursuant to §60.47(a)c, the permittee shall install, calibrate, maintain, and operate a continuous monitoring system for NO_x, and record the output of the system. If CEMS are installed to meet the requirements of part 75 and are continuing to meet the requirements of part 75, that CEMS may be used to meet this condition, except that the permittee shall also meet the requirements of §60.49a.

I. Pursuant to §60.47a(d), the permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

J. Pursuant to 40 CFR Part 60, Subpart Da, initial compliance testing for PM/PM_{10}, opacity, and NO_x (at 100% boiler load) is required within 180 days after startup. Testing shall be conducted in accordance with the test methods in 40 CFR Part 60 Appendix A or alternative approved methods.

32. Pursuant to 40 CFR §60.7(a), the following notifications to the Department are required for SN-01 and SN-02: (a) date of construction commenced postmarked no later than 30 days after such date, (b) anticipated date of initial startup between 30-60 days prior to such date, (c) actual date of initial startup postmarked within 15 days after such date, and (d) CEMS, opacity, and emissions performance testing 30 days prior to testing.

Acid Rain Program

33. The affected units (SN-01 through SN-04) are subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73, and 75).

34. Pursuant to 40 CFR Part 75 (Appendix A)- Continuous Emission Monitoring Subpart G, the submission of the NO_X, SO_2, and O_2 or CO_2 monitoring plan is required at least 45 days prior to the CEMS certification testing. Notice of CEMS certification testing is required at least 45 days prior to the CEMS certification testing. A copy of 40 CFR Part 75 is included in Appendix E.

35. Pursuant to 40 CFR Part 75 Subpart G - Continuous Emission Monitoring, a monitoring plan is required to be submitted for NO_X, SO_2, and O_2 or CO_2 monitoring.

36. Pursuant to 40 CFR Part 75 Subpart A, the initial NO_X, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences

commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860.

37. Pursuant to 40 CFR §75.10, the permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times, except during periods of calibration, quality assurance, preventative maintenance or repair.

SN-04 through SN-15

Cooling Tower Cells

Source Description

Hot Spring Power Company, L.L.C. operates one 215,000 gpm twelve-cell mechanical draft wet cooling tower (SN-04 through SN-15). Wet cooling towers provide direct contact between the cooling water and the air passing through the tower. Some of the liquid water becomes entrained in the air stream and may be carried out of the tower as “drift” droplets. Particulate matter is generated when the drift droplets evaporate and leave fine particulate matter formed by the crystallization of dissolved solids. The towers use a drift eliminator capable of reducing drift to 0.0005% drift of total recirculated water.

Specific Conditions

38. Pursuant to §19.501, §19.901, and 40 CFR 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table at SN-04 through SN-15 combined. Compliance with this condition will be demonstrated by compliance with Specific Condition 42.

Pollutant	lb/hr	tpy
PM_{10}	0.9	3.6

39. Pursuant to §18.801 and A.C.A., the permittee shall not exceed the emission rates set forth in the following table at SN-04 through SN-15 combined. Compliance with this condition will be demonstrated by Specific Condition 42.

Pollutant	lb/hr	tpy
PM	0.9	3.6

40. Pursuant to §19.901and 40 CFR 52, Subpart E, the permittee shall comply with the following BACT determination at SN-04 through SN-15. Compliance with the emission levels set forth in the following table shall be demonstrated by compliance with Specific Condition 42.

Pollutant	BACT Determination	
PM_{10}	drift eliminator (0.0005% drift efficiency)	0.9 lb/hr

41. Pursuant to §19.503 40 CFR 52 Subpart E, the permittee shall not cause to be discharged to the atmosphere from SN-04 through SN-15 exhausts which exhibit greater than 20% opacity. Compliance with this opacity limit shall be demonstrated by compliance with Specific Condition 42.

42. Pursuant to §18.1004, §19.705, 40 CFR 52, Subpart E, and A.C.A. the permittee shall not exceed in the circulated cooling water a total suspended particle level of 1500 ppmw.

43. Pursuant to §18.1004, §19.705, 40 CFR 52, Subpart E, and A.C.A. the permittee shall perform monthly testing or other monitoring with written approval by the Department that demonstrates compliance with Specific Condition 42. The permittee shall submit the test or other records to the Department in accordance with General Provision 7.

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Hot Spring Power Project is in compliance with the applicable regulations cited in the permit application. Hot Spring Power Project will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. Pursuant to §19.704 of Regulation 19, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the Director shall be notified in writing within thirty (30) days after construction has commenced, construction is complete, the equipment and/or facility is first placed in operation, and the equipment and/or facility first reaches the target production rate.

2. Pursuant to §19.410(B) of Regulation 19, 40 CFR Part 52, Subpart E, the Director may cancel all or part of this permit if the construction or modification authorized herein is not begun within 18 months from the date of the permit issuance or if the work involved in the construction or modification is suspended for a total of 18 months or more.

3. Pursuant to §19.702 of Regulation 19 and/or §18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, any equipment that is to be tested, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, shall be tested with the following time frames: (1) Equipment to be constructed or modified shall be tested within sixty (60) days of achieving the maximum production rate, but in no event later than 180 days after initial start-up of the permitted source or (2) equipment already operating shall be tested according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee shall notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. Compliance test results shall be submitted to the Department within thirty (30) days after the completed testing.

4. Pursuant to §19.702 of Regulation 19 and/or §18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, the permittee shall provide:

    a. Sampling ports adequate for applicable test methods
    b. Safe sampling platforms
    c. Safe access to sampling platforms
    d. Utilities for sampling and testing equipment

5. Pursuant to §19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C. A. §8-4-304 and §8-4-311, the equipment, control apparatus and emission monitoring equipment shall be operated within their design limitations and maintained in good condition at all times.

6. Pursuant to Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, this permit subsumes and incorporates all previously issued air permits for this facility.

Acid Rain (Title IV)

7. Pursuant to §26.701 of Regulation #26 and 40 CFR 70.6(a)(4), the permittee is prohibited from causing any emissions which exceed any allowances that the source lawfully holds under Title IV of the Act or the regulations promulgated thereunder. No permit revision is required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement of this permit or the Act. Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Act.

Title VI Provisions

8. The permittee shall comply with the standards for labeling of products using ozone depleting substances pursuant to 40 CFR Part 82, Subpart E:

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

9. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for MVACs in Subpart B:

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

c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" as defined at §82.152.)
e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
f. 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.

10. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR part 82, Subpart A, Production and Consumption Controls.

11. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    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.

12. The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR part 82, Subpart G, Significant New Alternatives Policy Program.

SECTION VII: INSIGNIFICANT ACTIVITIES

Pursuant to §26.304 of Regulation 26, the following sources are insignificant activities. Any activity for which a state or federal applicable requirement applies is not insignificant even if this activity meets the criteria of §304 of Regulation 26 or is listed below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated March 8, 2001.

Description	Category
246 gallon diesel tank	A-2
Emergency diesel fire-water pump	A-12
2 - 12,000 gallon ammonia vessels	B-21
500 Gallon sodium hypochlorite tank 10,000 gallon sulfuric acid tank	B-44
100 gallon water treatment system for boiler feed water	B-42 and B-43
One Process Heater (natural gas & rated less than 10 MMBtu/hr)	A-1

Pursuant to §26.304 of Regulation 26, the emission units, operations, or activities contained in Regulation 19, Appendix A, Group B, have been determined by the Department to be insignificant activities. Other activities included in this list that were not listed above are allowable under this permit and need not be specifically identified.

SECTION VIII: GENERAL PROVISIONS

1. Pursuant to 40 CFR 70.6(b)(2), any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute.

2. Pursuant to 40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective August 10, 2000, this permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later.

3. Pursuant to §26.406 of Regulation #26, it is the duty of the permittee to submit a complete application for permit renewal at least six (6) months prior to the date of permit expiration. Permit expiration terminates the permittee's right to operate unless a complete renewal application was submitted at least six (6) months prior to permit expiration, in which case the existing permit shall remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due.

4. Pursuant to 40 CFR 70.6(a)(1)(ii) and §26.701(A)(2) of Regulation #26, where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions are incorporated into the permit and shall be enforceable by the Director or Administrator.

5. Pursuant to 40 CFR 70.6(a)(3)(ii)(A) and §26.701(C)(2) of Regulation #26, records of monitoring information required by this permit shall include the following:

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;
d. The analytical techniques or methods used;
e. The results of such analyses; and
f. The operating conditions existing at the time of sampling or measurement.

6. Pursuant to 40 CFR 70.6(a)(3)(ii)(B) and §26.701(C)(2)(b) of Regulation #26, records of all required monitoring data and support information shall be retained for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

7. Pursuant to 40 CFR 70.6(a)(3)(iii)(A) and §26.701(C)(3)(a) of Regulation #26, the permittee shall submit reports of all required monitoring every 6 months. If no other reporting period has been established, the reporting period shall end on the last day of the anniversary month of this permit. The report shall be due within 30 days of the end of the reporting period. Even though the reports are due every six months, each report shall contain a full year of data. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official as defined in §26.2 of Regulation #26 and must be sent to the address below.

Arkansas Department of Environmental Quality
Air Division
ATTN: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219

8. Pursuant to 40 CFR 70.6(a)(3)(iii)(B), §26.701(C)(3)(b) of Regulation #26, and §19.601 and 19.602 of Regulation #19, all deviations from permit requirements, including those attributable to upset conditions as defined in the permit shall be reported to the Department. An initial report shall be made to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

a. The facility name and location,
b. The process unit or emission source which is deviating from the permit limit,
c. The permit limit, including the identification of pollutants, from which deviation occurs,
d. The date and time the deviation started,

e. The duration of the deviation,
f. The average emissions during the deviation,
g. The probable cause of such deviations,
h. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and
i. The name of the person submitting the report.

A full report shall be made in writing to the Department within five (5) business days of discovery of the occurrence and shall include in addition to the information required by initial report a schedule of actions to be taken to eliminate future occurrences and/or to minimize the amount by which the permits limits are exceeded and to reduce the length of time for which said limits are exceeded. If the permittee wishes, they may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence and such report will serve as both the initial report and full report.

9. Pursuant to 40 CFR 70.6(a)(5) and §26.701(E) of Regulation #26, and A.C.A.§8-4-203, as referenced by §8-4-304 and §8-4-311, if any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity shall not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable.

10. Pursuant to 40 CFR 70.6(a)(6)(i) and §26.701(F)(1) of Regulation #26, the permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation #26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Any permit noncompliance with a state requirement constitutes a violation of the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) and is also grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

11. Pursuant to 40 CFR 70.6(a)(6)(ii) and §26.701(F)(2) of Regulation #26, 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 this permit.
12. Pursuant to 40 CFR 70.6(a)(6)(iii) and §26.701(F)(3) of Regulation #26, this permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or

termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

13. Pursuant to 40 CFR 70.6(a)(6)(iv) and §26.701(F)(4) of Regulation #26, this permit does not convey any property rights of any sort, or any exclusive privilege.

14. Pursuant to 40 CFR 70.6(a)(6)(v) and §26.701(F)(5) of Regulation #26, the permittee shall furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Director copies of records required to be kept by the permit. For information claimed to be confidential, the permittee may be required to furnish such records directly to the Administrator along with a claim of confidentiality.

15. Pursuant to 40 CFR 70.6(a)(7) and §26.701(G) of Regulation #26, the permittee shall pay all permit fees in accordance with the procedures established in Regulation #9.

16. Pursuant to 40 CFR 70.6(a)(8) and §26.701(H) of Regulation #26, no permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for elsewhere in this permit.

17. Pursuant to 40 CFR 70.6(a)(9)(i) and §26.701(I)(1) of Regulation #26, if the permittee is allowed to operate under different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the scenario under which the facility or source is operating.

18. Pursuant to 40 CFR 70.6(b) and §26.702(A) and (B) of Regulation #26, all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Act unless the Department has specifically designated as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements.

19. Pursuant to 40 CFR 70.6(c)(1) and §26.703(A) of Regulation #26, any document (including reports) required by this permit shall contain a certification by a responsible official as defined in §26.2 of Regulation #26.

20. Pursuant to 40 CFR 70.6(c)(2) and §26.703(B) of Regulation #26, the permittee shall allow an authorized representative of the Department, upon presentation of credentials, to perform the following:

    a. Enter upon the permittee's premises where the permitted source is located or emissions-related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with this permit or applicable requirements.

21. Pursuant to 40 CFR 70.6(c)(5) and §26.703(E)(3) of Regulation #26, the permittee shall submit a compliance certification with terms and conditions contained in the permit, including emission limitations, standards, or work practices. This compliance certification shall be submitted annually and shall be submitted to the Administrator as well as to the Department. All compliance certifications required by this permit shall include the following:

    a. The identification of each term or condition of the permit that is the basis of the certification;
    b. The compliance status;
    c. Whether compliance was continuous or intermittent;
    d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
    e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and 504(b) of the Act.

22. Pursuant to §26.704(C) of Regulation #26, nothing in this permit shall alter or affect the following:

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. Pursuant to A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, this permit authorizes only those pollutant emitting activities addressed herein.

APPENDIX A

Custom Fuel Monitoring Schedule

Fuel Monitoring Protocol for Stationary Turbines Subject to 40 CFR Part 60, Subpart GG

1. Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

2. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The approved reference methods are: ASTM Dl072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2). The Gas Processors Association (GPA) test method entitled "Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes" (GPA Standard 2377-86) is an approved alternative method.

3. The fuel supply shall be initially sampled daily for a period of two weeks to establish that the sulfur content of the pipeline quality natural gas fuel supply is less than or equal to two grains per 100 dscf.

4. After the monitoring required in item 3 above, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

5. If after the monitoring required in item 4 above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

6. Should any sulfur analysis as required in items 4 or 5 above indicate noncompliance with40 CFR 60.333, the owner or operator shall notify the ADEQ of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

7. If there is a change in fuel supply (supplier), the fuel shall be sampled daily for a period of two weeks to re-establish for the record that the fuel supply is low in sulfur content. If the fuel supply's low sulfur content is re-established, then the custom fuel monitoring schedule can be resumed.

8. Stationary gas turbines that use the same supply of pipeline quality natural gas to fuel multiple gas turbines may monitor the fuel sulfur content at a single common location.

9. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

10. Other monitoring schedules or variances in this schedule may be acceptable only if approved by the Administrator.

APPENDIX B

ADEQ CEMS Conditions

APPENDIX C

40 CFR, Part 60, Subpart GG

APPENDIX D

40 CFR Part 60, Subpart Da

APPENDIX E

40 CFR Part 75

APPENDIX F

Alternative Approval for Compliance with 40 CFR 60, Subpart Da

Mr. Emmett Poindexter
Manager, Environmental Services
Duke Energy
5400 Westheimer Court
Suite 4G-38
Houston, TX 77056

Dear Mr. Poindexter:

This letter responds to your June 19, 2000 request for approval of an alternative method of determining compliance with 40 CFR Part 60, Section 60.44a(d)(1) for the Arlington Valley Energy Project (AVEP) in Maricopa County, Arizona. Specifically, you proposed to use a continuous monitoring system (CMS) to monitor fuel input rate (+/-2 percent), measure Gross Calorific Value (GCV) of the natural gas burned, and using the F-Factor approach described in Method 19 together with data from a Part 75 certified NOx CMS and the gross electrical output of the combined unit, to demonstrate compliance with the output based standard of 40 CFR Part 60, Section 60.44a(d)(1). The details of such monitoring, record keeping and reporting will be detailed in an Emissions Monitoring Compliance Plan for the AVEP facility to be submitted and approved by the Administrator as required under 40 CFR Part 75. Pursuant to 40 CFR Part 60, Section 60.13(i), the U.S. Environmental Protection Agency (EPA) hereby approves your request. The following discussion provides our rationale for this approval.

Maricopa County determined that 40 CFR Part 60, Subpart GG will apply to AVEP's gas turbines and Subpart Da will apply to the duct burners in the Heat Recovery Steam Generator (HRSG) upon construction of this plant. You have indicated that your duct burner operates as part of a combined cycle power generation system and the duct burner cannot operate independently of the turbine. The combined effluent is exhausted through a common selective catalytic reduction (SCR) NOx control system and stack which makes it impractical to isolate the emissions emitted to the atmosphere from the duct burner from those of the host combustion turbine. The thermal energy produced from the duct burner also combines with thermal energy from the turbine to produce electricity in a common steam turbine/generator. In this case, an alternative method of determining compliance is appropriate.

You have indicated that there is a proposed federally enforceable NOx permit limit of 3 ppmvd @ 15 percent O_2 for the combined cycle system which is more stringent than the Subpart Da emission limit. Assuming that you will comply with the 3 ppmvd @ 15 percent O_2 limit, this

is equivalent to about 6 percent of the emission limitation of Subpart Da. This provides an ample margin of safety to compensate for the assumption that we have to make that the thermal efficiency of the turbine and duct burner are the same.

If you have questions about this letter, contact Terry Harrison at US EPA, Emission Measurement Center, MD-19, Research Triangle Park, NC, 27711 or E-Mail address harrison.terry@epa.gov

Sincerely,

J. David Mobley, Acting Director
Emissions, Monitoring & Analysis Division

cc: Director, Air Division (Region 9)
Steve Frey (Region 9)
Ms. Elena Gorelik, Maricopa County ESD
Mr. Max Shilstone, Duke Energy
Sara Head, ENSR

bcc: Sims Roy (MD 13)
Jim Eddinger (MD 13)
Chris Oh, OC, OECA, (MC 2223A)

OAQPS/EMAD/SMTG/RTHARRISON/lac/541-5233/08/25/00/MD-19
FILE #___________ DOC NAME:***F:\USER\THARRISON\TYPE\ENSRAVEP.WPD***

Addresses:

Mr. Emmett Poindexter
Manager, Environmental Services
Duke Energy
5400 Westheimer Court
Suite 4G-38
Houston, TX 77056

Duke Energy's Maricopa contact:
Mr. Max Shilstone
Duke Energy Maricopa
40 North Central Avenue
Phoenix, Arizona 85004-4429

Ms. Elena Gorelik
Permit Engineer
Maricopa County Environmental Services Department
1001 North Central Avenue
Phoenix, Arizona 85004

Ms. Sara Head
ENSR
1220 Avenida Acaso
Camarillo, CA 93012

INVOICE REQUEST FORM

PDS-

Date August 6, 2003

☒ Air
☐ NPDES
☐ Stormwater
☐ State Permits Branch
☐ Solid Waste

CSN 30-0337

Facility Name Hot Spring Power Project

Invoice Mailing Address 1177 West Loop South, Suite 900
Houston, TX 77027

☒ Initial
☐ Modification
☐ Annual

Permit Number 1987-AOP-R0
Permit Description Title 5
Permit Fee Code A

Amount Due$ 17,891

Engineer Leamons

Paid? ☐No ☐Yes Check #

Comments: Air Permit Fee Calculation

(240+13.2+70.3+294.6+311.6+6.0)*19.12= $17,890.58

Public Notice

Pursuant to the Arkansas Operating Air Permit Program (Regulation #26) Section 602, the Air Division of the Arkansas Department of Environmental Quality gives the following notice:

Hot Spring Power Project has applied for an initial Title V, major source air permitting. The facility, (CSN: 30-0337), is located off Hwy 270, 6 miles west of Malvern, AR 72104. Upon final issuance by the Department, the permit will allow the facility to construct and operate two natural gas combustion turbines with associated steam generating units and other supporting equipment including storage tanks and cooling systems. The facility will be a merchant power producer capable of generating 815 MW of electricity.

The application has been reviewed by the staff of the Department and has received the Department's tentative approval subject to the terms of this notice.

Citizens wishing to examine the permit application and staff findings and recommendations may do so by contacting Suzanne Carswell, Information Officer. Citizens desiring technical information concerning the application or permit should contact Bryan Leamons, Engineer. Both Suzanne Carswell and Bryan Leamons can be reached at the Department's central office, 8001 National Drive, Little Rock, Arkansas 72209, telephone: (501) 682-0744.

The draft permit and permit application are available for copying at the above address. A copy of the draft permit has also been placed at the Garland County Library, 1427 Malvern Avenue, Hot Springs, AR 71901. This information may be reviewed during normal business hours.

Interested or affected persons may also submit written comments or request a hearing on the proposal, or the proposed modification, to the Department at the above address - Attention: Suzanne Carswell. In order to be considered, the comments must be submitted within thirty (30) days of publication of this notice. Although the Department is not proposing to conduct a public hearing, one will be scheduled if significant comments on the permit provisions are received. If a hearing is scheduled, adequate public notice will be given in the newspaper of largest circulation in the county in which the facility in question is, or will be, located.

The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Section 2.1 of the Arkansas Pollution Control and Ecology Commission's Administrative Procedures (Regulation #8) and Regulation #26.

Dated this

Richard A. Weiss
Interim Director