FINAL DETERMINATION

To Grant a

Prevention of Significant Deterioration Permit

and

Non-Attainment Permit

for

AES Londonderry, L.L.C.

To construct a

720 MW Combustion Turbine Facility

in

Londonderry, NH

Prepared by the

United States Environmental Protection Agency
Region I

and

New Hampshire Department of Environmental Services
Air Resources Division

April 26, 1999

I. **Applicant's Name:**

AES Londonderry, L.L.C.
50 Nashua Road
Suite 202
Londonderry, NH 03053

II. **Physical Address of Proposed Facility:**

Londonderry Ecological Industrial Park
Londonderry, NH

County: Rockingham
USGS Coordinates: Easting: 301.9 Northing: 4752.8

III. **Background:**

A new major source of air pollution seeking to locate in an attainment area is subject to review in accordance with the provisions of 40 CFR Section 52.21, *Prevention of Significant Deterioration* ("PSD"). The PSD program in New Hampshire is administered by the New Hampshire Department of Environmental Services, Air Resources Division ("DES"). Under the New Hampshire PSD Operating Plan, DES is responsible for completing the Preliminary Determination and Draft Permit, while EPA Region I ("EPA") issues the PSD permit.

Likewise, a new major source of air pollution seeking to locate in a non-attainment area is subject to review in accordance with the provisions of New Hampshire Rules Governing the Control of Air Pollution Part Env-A 622 *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Ozone Transport Region*. Unlike the PSD Permit Program, DES is fully delegated by EPA with respect to Non-Attainment Review. Therefore, the Non-Attainment permit is issued by DES.

On July 6, 1998, AES Londonderry, L.L.C. ("AES") submitted an Application for Certificate of Site and Facility to the New Hampshire Energy Facility Site Evaluation Committee ("EFSEC"). Included in the application to EFSEC, AES identified the need to obtain a PSD and Non-Attainment Permit to construct and operate a 720 MW Combined-Cycle Combustion Turbine facility in Londonderry, NH.

DES issued a Public Notice that was published in the Union Leader and Derry News Newspapers indicating that DES hade made a Preliminary Determination to grant a PSD/Non-Attainment Permit to AES. On February 25, 1999 DES held a Public Hearing at the Londonderry High School to receive public comment on the Preliminary Determination for AES. Public comments received during the hearing and subsequent comment period have been reviewed by DES and EPA and have been taking into consideration in making this Final Determination.

The issuance of this Final Determination is done jointly and concurrently by DES and EPA. The New Hampshire DES has an EPA-approved nonattainment New Source Review (NSR) permit program and will issue the LAER and offset permit provisions regarding the nonattainment pollutant NOx. In addition, New Hampshire has EPA approved procedures to ensure new construction or modifications of stationary sources do not violate control strategies or interfere with attainment of maintenance standards. These procedures authorize the DES to regulate non-significant increases for all criteria and regulated pollutants. New Hampshire does not, however, have full authority to issue PSD permits. EPA has partially delegated the PSD program to New Hampshire, authorizing the state to do the administrative and technical work on the permit, but has retained the authority for EPA to make the final decision and issue the final PSD permit. Consequently, EPA is issuing the permit provisions requiring BACT for such attainment pollutants as carbon monoxide, sulfur dioxide and particulate matter. Rather than issuing to the source two different permits (PSD and nonattainment NSR), EPA and New Hampshire DES have arranged the issuance of a joint permit that clearly delineates the EPA and DES provisions.

Since EPA is the issuing authority for the PSD provisions of the permit, any petitions to the PSD provisions should be made to EPA in accordance with 40 CFR Part 124. Since DES is the issuing authority for the nonattainment NSR provisions and the non-significant emissions provisions, any petitions related to these provisions should be made to the Air Resource Council in accordance with Env-A 205.10 *Appeals*.

As mentioned, EPA has final authority for the issuance of the PSD provisions of the permit. However, the DES is authorized to administer the PSD program and as the PSD administrator is responsible for the following actions: 1) receiving PSD applications, 2) developing preliminary technical findings including air impact analysis and BACT limit findings, 3) drafting preliminary determinations and PSD permit and 4) providing public notice and opportunity for public comment on draft determinations and permits. As the final PSD authority, EPA provided comments and recommendations during the public comment period and adopted the final PSD determination and permit provisions based upon those comments. The following final determination and permit contain both EPA's recommendations and findings.

IV. Project Description:

AES is proposing to construct and operate a 720 MW combined cycle power facility in Londonderry, NH. The AES facility will consist of two identical combustion turbine trains. The major components of each combustion turbine train includes a combustion turbine generator, an un-fired exhaust heat recovery steam generator ("HRSG"), a combined steam turbine generator, a combined wet mechanical draft cooling tower, a water treatment system and auxiliary equipment.

AES will operate two identical Westinghouse Model 501 G combustion turbines, each with a capacity of approximately 243 MW. The exhaust gas from each turbine will pass through the HRSGs which will generate steam. This steam will be used to drive a combined steam turbine which will produce an additional 248 MW of electric power. AES has proposed that no supplemental fuel firing will occur in the HRSGs. Plant electrical usage will be approximately 14 MW, which brings the nominal rating of the plant to 720 MW. Air pollution controls at the facility will include a NO_x reduction system, a CO control system and Continuous Emission Monitors ("CEMs") for CO, NO_x, opacity and other operational parameters.

Cooling water for the proposed AES facility will supplied by piping effluent from the Manchester Waste Water Treatment facility. Approximately 97% of the water used by the facility will be used for cooling purposes, the majority of which will leave the facility as evaporative losses from the cooling tower. AES has estimated that on average 3.62 million gallons of water per day will be used by the facility.

V. General Information:

A. PSD/Non-Attainment Applicability Determination & Attainment Status:

AES is proposing to construct and operate a 720 MW Combined Cycle Combustion Turbine facility in Londonderry, NH. The proposed facility will be located in Rockingham County which is classified as an attainment area for Carbon Monoxide ("CO"), Sulfur Dioxide ("SO_2"), Nitrogen Oxides ("NO_x") and Particulate Matter ("PM"), including Particulate less than 10 microns in diameter ("PM-10"), and therefore, a PSD area for these pollutants. Rockingham county is also classified as a non-attainment area for Ozone, and therefore, a non-attainment area for Ozone precursors, namely, NO_x and Volatile Organic Compounds ("VOCs"). In addition, the entire state is part of the Northeast Ozone Transport Region ("OTR") and is required to implement at a minimum ozone nonattainment NSR requirements equivalent to the moderate ozone nonattainment NSR requirements for all parts of the state. The Region has proposed to remove the ozone nonattainment designation based on the last three years of data meeting the one-hour standard National Ambient Air Quality Standard. When EPA finalizes this action, the nonattainment requirements of OTR would still apply.

The proposed AES facility will have emissions of regulated attainment pollutants above the major source PSD thresholds and therefore is subject to PSD review and will require a PSD Permit. As noted in Section III, PSD permit issued in New Hampshire are issued by EPA. In addition, the proposed facility will have emissions of regulated nonattainment pollutants above the major source nonattainment thresholds and therefore is subject to non-attainment review and will require a Nonattainment Permit. Nonattainment Permits issued in New Hampshire are issued by DES as noted in Section III.

B. Site Information:

The proposed facility will be located on 47.7 acres within the 100- acre Londonderry Ecological Industrial Park in Londonderry, NH. The town of Londonderry is located in Rockingham County in the south east portion of New Hampshire. The site is approximately 1.4 miles south of Manchester Airport and 1.2 miles east of the Merrimack River. The topography surrounding the proposed project site is somewhat hilly, characterized in general by elevated terrain to both the east and west of the Merrimack River valley. There are a number of hills within 2 miles of the site which extend to above 400 feet, the closest being about one half mile to the east at an elevation of 420 feet. Beyond this hill the terrain descends into a marshy plain bisected by Cohas Brook. A number of smaller creeks are also present in the area. The highest elevation in the general area is 490 feet, which is located in the hills just east of Manchester Airport. The proposed facility is to be located at an elevation of approximately 300 feet above mean sea level, which is 200 feet above the floor of the river valley.

AES has identified several residential subdivisions within ½ mile of the proposed project site. Approximately, 101 dwellings are located within ½ mile from the nearest project structures and an additional 43 dwellings are located within ½ mile of the proposed site property line. The residential dwellings are concentrated around the Yellowstone Drive loop and nearby streets, along Woodside Drive, Sandy Brook Lane, Maureen Circle and Litchfield Road.

C. Operation Information:

The proposed AES facility will provide approximately 720 MW of electricity to the regional electric transmission grid. The proposed project will consist of two identical combustion turbine trains, each consisting of a combustion turbine generator rated at 243 MW, an unfired HRSG, and a combined steam turbine generator rated at 248 MW. AES has proposed operating the facility on a base loaded basis, i.e. 100 % of rated output for up to 24 hours per day, 365 days per year. The only periods of downtime are expected to be for periods of maintenance and repair services.

Primary fuel for the proposed facility will be natural gas piped from the Tennessee Gas Pipeline Company's "Concord Lateral". The direct gas line interconnect, or Project Lateral pipeline, is expected to be built, owned and operated by a third party. Backup fuel for the proposed facility will be low sulfur distillate fuel oil with a sulfur content of 0.05 % by weight. AES has proposed limiting fuel oil combustion to 720 hours per twelve month rolling period, which is equivalent to 30 days per year or approximately 29,150,000 gallons.

D. Quantification of Emissions:

AES is classified as a new major source of air emissions. Emissions of regulated pollutants will be limited to the following levels:

Table 1. Emission Limitations for AES

Pollutant	Maximum Emissions (TPY)	PSD Threshold (TPY)	PSD Significance Threshold (TPY)	Non-Attainment Threshold (TPY)
Nitrogen Oxides (NOx)	264.2	100	40	50
Carbon Monoxide (CO)	928.9	100	100	N/A
Volatile Organic Compounds (VOCs)	49.9	N/A	N/A	50
Total Particulate (PM)	128.7	100	25	N/A
PM-10	128.7	100	15	N/A
Sulfur Dioxide (SO_2)	153.5	100	40	N/A
Total HAPs	3.96	N/A	N/A	N/A
Ammonia	307.3	N/A	N/A	N/A
Lead	0.12	100	0.6	N/A

The above emissions were estimated based on the following assumptions:

1). The plant is operated at a load that would produce the worst case emissions, i.e. for natural gas firing at an ambient temperature of 50 °F and for distillate firing at an ambient temperature of 0 °F.

2) Annual emissions are based on a maximum of 720 hours per year of distillate fuel oil firing.

3) The sulfur content of distillate fuel oil is 0.05 % by weight.

Based on the above emission rates the proposed AES facility is subject to PSD review for Sulfur Dioxide, Nitrogen Oxides, Particulate Matter (including PM-10), Carbon Monoxide and Sulfur Acid Mist. The proposed facility is also subject to Non-attainment review for Nitrogen Oxides.

VI. Additional Regulatory Air Pollution Requirements

A. Federal NSPS Standards for Stationary Gas Turbines:

The combustion turbines at the proposed AES facility will be subject to the New Source Performance Standard ("NSPS"), 40 CFR 60 Subpart GG, *Standards of Performance for Stationary Gas Turbines* ("Subpart GG") which establishes performance standards for NO_x and SO_2. In addition, Subpart GG also specifies certain monitoring, recordkeeping and reporting requirements. The proposed facility will have emissions rates that are below the NO_x and SO_2 performance standards and the permit for the facility will contain the applicable monitoring, recordkeeping and reporting requirements of the Subpart GG. DES is delegated by EPA to enforce Subpart GG as it pertains to stationary gas turbines.

B. Federal NSPS Standards for Volatile Organic Liquid Storage Vessels:

Fuel oil for the proposed AES Facility will be stored on-site in fuel oil storage vessels which are subject to the NSPS, 40 CFR 60 Subpart Kb *Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced after July 23, 1984* ("Subpart Kb"). Due to the low vapor pressure of distillate fuel oil, the facility is only required to maintain records of the tank dimensions and the maximum capacity of the tanks. DES is delegated by EPA to enforce Subpart Kb as it pertains to volatile organic liquid storage vessels.

C. Federal Acid Rain Program:

In accordance with 40 CFR Part 72, *Federal Acid Rain Requirements*, AES will be designated as a Phase II New Affected Unit, effective January 1, 2000, or within 90 days after commencement of commercial operation, whichever is later. AES will need to submit a Phase II Acid Rain Application in accordance with the requirements of 40 CFR Part 72. As required by the Federal Acid Rain Program, AES will be required to acquire SO_2 allowances in the amount of one allowance for each ton of SO_2 emitted in accordance with 40 CFR Part 72. In addition, AES may be required to install CEMs that meet the applicable requirements of 40 CFR Part 75.

D. Federal Accidental Release Requirements - Clean Air Act Section 112(r):

AES has indicated that the proposed facility will not be subject to the provisions of 40 CFR Part 68 *Chemical Accident Prevention Provisions* or the Federal Accidental Release Program. In the application AES stated that the concentration of aqueous ammonia stored on site will be below the applicability threshold (20 % or greater) of 40 CFR Part 68. However, if AES later decides to store aqueous ammonia or any other chemical in concentrations or quantities above the applicability threshold of 40 CFR Part 68, a Risk Management Plan must be prepared and submitted no later than the latest of the following dates:

1. June 21, 1999;

2. Three years after the date on which a regulated substance is first listed under 40 CFR 68.130; or

3. The date on which a regulated substance is first present above a threshold quantity in a process.

E. Maximum Achievable Control Technology Requirements for New Sources - Clean Air Act Section 112(g):

AES is not subject to Section 112(g) requirements since electric utility steam generating facilities are exempt in accordance with 40 CFR Part 63.40 (c) unless and until such time as these units are added to the source category list pursuant to section 112(c)(5) of the Act. In addition, potential Hazardous Air Pollutant ("HAP") emissions from the proposed facility are below the applicability thresholds (10 tons of any single HAP or 25 tons of all HAPs combined) of Section 112(g).

F. State Standards:

DES has a number of air pollution regulations that would be applicable to the proposed AES facility. These applicable regulations are adopted under authority of RSA 125-C, 125-I and 125-J and are codified in the New Hampshire Code of Administrative Rules. The substantive portions of these state requirements include, but are not limited to, the sections listed below:

1. Chapter Env-A 200 - *Procedural Requirements*.

2. Chapter Env-A 600 - *Statewide Permit System.*

3. Part Env-A 622 - *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Ozone Transport Region.*

4. Chapter Env-A 700 - *Permit Fee System*

5. Chapter Env-A 800 - *Testing and Monitoring Procedures*

6. Chapter Env-A 900 - *Recordkeeping and Reporting Requirements*

7. Chapter Env-A 1400 - *Toxic Air Pollutants Standards*

8. Chapter Env-A 3200 - *Special Temporary Rule on NO_x Budget Trading Program*

VII. PSD Control Technology Review:

This portion of the Final Determination has been prepared by EPA as noted in Section III.

The proposed AES facility is subject to Best Available Control Technology ("BACT") for Particulate Matter, Sulfur Dioxide, Sulfuric Acid Mist, Carbon Monoxide and Nitrogen Oxides. In addition, the proposed AES facility is also subject to Lowest Achievable Emission Rate ("LAER") for Nitrogen Oxides. Both State and Federal regulations and policies define BACT as an emission limitation based on the maximum degree of reduction for each regulated pollutant taking into consideration technical, economic and environmental factors. In no case shall the BACT emission limitation result in emissions of any pollutant in excess of any applicable standard under 40 CFR Part 60 *Standards of Performance for New Stationary Sources of Air Pollution* and 40 CFR Part 61 *National Emission Standards for Hazardous Air Pollutants*.

In its application, AES conducted their BACT analysis by first identifying technically feasible control options, which included a search of the EPA RACT/BACT/LAER Clearinghouse ("RBLC"). Secondly, AES took into consideration any environmental and energy impacts of a particular control option. Thirdly, AES performed an economic analysis where appropriate. Finally, AES made a proposal of BACT for each pollutant taking into consideration the factors above. AES also conducted a search of the RBLC in order to propose the LAER limits for NO_x. In addition, AES reviewed recently issued construction permits for similar facilities in the Northeast.

In conducting the Preliminary Determination for BACT, the New Hampshire DES went through the same process for proposing BACT. In the Final Determination, EPA has also used this methodology in arriving at the final BACT determination.

A. Availability of SCONOx Technology

In determining BACT for several pollutants, EPA and DES carefully considered whether SCONOx is an available technology for purposes of the BACT determination. While SCONOx is primarily aimed at controlling NO_x emissions, the manufacturer of SCONOx has also cited its ability to reduce carbon monoxide, sulfur dioxide, and particulate matter, among other pollutants. Consequently, the availability of this technology is an important threshold question for the following BACT determinations.

A commentor did request that the DES and EPA evaluate SCONOx technology as a control for CO based on the technology's ability to limit CO emissions while achieving LAER for NO_x. The commentor asserted that SCONOx does not use ammonia and, consequently, will have less secondary environmental impact as compared with other controls. In comments to the Preliminary Determination prepared by DES, EPA also urged that the DES verify the current availability of SCONOX before determining LAER for the non-attainment pollutant and developing BACT terms for EPA's PSD portion of the permit.

EPA's procedures for performing a top-down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible. If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward. If the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if can be obtained through commercial channels. An available control is applicable if it can be reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new techniques. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

In addition, as mentioned before, the manual also requires available technologies to be applicable to the source type under consideration before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility. However, even in this instance, the manual would allow an applicant to make a demonstration to the contrary. For example, the applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site and operating problems related to the specific circumstances of the source) make a control technical infeasible.

EPA believes that SCONOx holds substantial promise for the reduction of pollutants from power plants. However, at this time, after considering the information received from the applicant and from other sources including the manufacturer and licensee of the SCONOx technology, EPA concludes that SCONOx is not yet technically feasible for large combined cycle plants today.

In reaching this conclusion, EPA relies upon technical uncertainties about the application of this control technology to the large combined cycle turbines proposed by the applicant. While SCONOx has been successfully utilized on a 32-megawatt gas turbine at the Federal Cogeneration facility in Vernon, California, the applicant will use a 283-megawatt turbine. Given the very substantial difference in scale (more than 8 times) and the resulting need to modify the equipment in order to "scale up" the equipment, EPA is not able to determine that the equipment has been installed and operated on the type of source under review. EPA has consequently considered whether the equipment is both "available" and "applicable" in order to determine whether it is technically feasible. The applicant has pointed to a number of unresolved technical issues in applying SCONOx to its larger 283-megawatt turbine, related to both the scale up of the technology and other differences between the demonstrated SCONOx equipment and the equipment which would be installed on the applicant's plant. While minor technical issues about application of control technology equipment to a different or larger facility should not result in a conclusion of lack of availability or applicability, EPA has concluded that several of the technical issues raised by the applicant are sufficiently serious as to warrant such a conclusion. As noted in the Manual, an applicant is not expected to experience substantial commercial risk or extended trials to work out how to apply technology on a dissimilar source type.

In the following paragraphs, EPA notes certain significant unresolved technical issues about application of SCONOx to the larger turbine proposed by the applicant. EPA is optimistic that these issues can and will be worked out, and before long SCONOx should be considered available technology for BACT determinations. However, at this moment, these issues raised by the applicant, are legitimate. While any one concern may not be conclusive, combined they lead EPA to conclude that it cannot deem SCONOx technically feasible yet.

Increased Gas Flow: Based upon the application and EPA and DES investigation, EPA believes that SCONOx has only been demonstrated on a 32-MW gas turbine. The applicant's proposed Westinghouse 501G gas turbine would have a nominal rating of 243 MW. The exhaust gas flow for the applicant's turbine will be about nine times greater than the turbine on which SCONOx has been demonstrated. The applicant has argued that this substantially increased gas flow raises significant scale up issues, including possible adverse impacts from gas flow distribution and disturbances from the SCONOx system. The SCONOx technology relies upon periodic blockage of the gas flow in order to allow for regeneration of the catalyst modules. The applicant notes that gas flow distribution and blockage may impact the operation and performance of the heat recovery steam generator. Goal Line, on the other hand, believes that SCONOx can accommodate this scale up. EPA believes that the use of the equipment in a turbine with nearly eight times the gas flow do raise legitimate concerns about the effect of the equipment on the performance of the turbine.

Louver System Scale-Up: SCONOx technology uses a louver system to alternately close off sections of the catalyst to allow for the regeneration of the catalyst. The applicant indicates that proper louver operation is critical to successful operation of the system. As mentioned, SCONOx has been installed on a significantly smaller unit then the Westinghouse unit. In addition, the Federal facility's SCONOx system was designed and installed for the "cold end" (300-350F) portion of the flue.

For larger turbine application, Goal Line is designing a larger louver system that can accommodate the larger flue stream. Goal Line also envisions installing the system and louvers in the hot end of the flue (500-700 F). The applicant does not believe Goal Line's federal facility has sufficiently demonstrated the long term reliability or performance of Goal Line's new louver design and location. In conversations with Goal Line, Goal Line indicated the new louver design has been completed and evaluated and that no significant issues exist. EPA also notes that Goal Line's licensee, ABB, is currently testing the scaled-up louver design. However, the fact that the results from ABB is currently testing the design and the results of these tests are not yet final or available, and that the system has not been installed and operated on larger units, does raise legitimate questions about whether the new louver design is available for large turbine projects today.

Sulfur Removal: The applicant indicates that Goal Line intends to use a different sulfur scrubbing technology from the technology operating at the Federal Cogeneration facility. The applicant indicates the use of the new and untried technology raises reliability issues. Goal Line has indicated that SCOSOx has been demonstrated on smaller oil firing engines and that scale up should be feasible. In addition, Goal Line notes sulfur removal only improves the systems performance but is not a prerequisite for its use.

Most of Goal Line's experience is with the Federal Cogeneration facility that combusts natural gas only. The New Hampshire project would allow for the combustion of distillate oil up to thirty days per year. Goal Line indicated that for large turbines burning distillate, sulfur removal would be needed for commercial operation. For these projects, EPA believes the lack of operating experience with SCOSOx on larger distillate burning turbines does raise legitimate concerns about its availability.

Methane Use for Regeneration: The Federal Cogeneration facility currently employs diluted hydrogen gas for catalyst regeneration. Goal Line currently recommends a dilute methane for regeneration. The applicant indicates the new design has not been demonstrated. Goal Line indicates the new design is an improvement over the current design but in any case the old design could be used for larger units. Again, EPA is concerned about the lack of operational experience that Goal Line has on its current design.

The validity of these concerns about the technical feasibility of SCONOx on larger facilities is supported by the actions and statements of Goal Line's SCONOx licensee, ABB, a world leader in turbine design and pollution control technologies. Goal Line has entered into a licensing agreement with ABB for commercial marketing rights for SCONOx for gas turbine plants over 100 megawatts. ABB has made clear that it does not believe that the technology is sufficiently demonstrated on larger facilities yet. Vendor and licensee statements should not determine the availability or lack thereof of a particular technology. However, the concerns of the licensee of equipment, which has a financial stake in its use, about the readiness of the product for use on larger combined cycle turbines do provide additional support for the validity of the technical concerns raised by the applicant.

Specifically, ABB has stated in letters to state regulators that a large scale SCONOx design confirmed suitable for integration into ABB's large combined cycle plants does not exist at this time. ABB confirms its intent to eventually commercialize a SCONOx design for large scale combined cycle plants with reliability, availability and maintainability profiles comparable to existing SCR-based plants. To that end, ABB states that it is designing and testing a prototype system to ensure SCONOx is compatible with large combined cycle plant operations. ABB anticipates the testing program will be completed shortly. Until testing is completed, ABB has indicated that it will not guarantee the performance of the system, including shouldering liquidated damages (i.e., lost revenue) in the event the equipment fails to obtain a promise level of availability. ABB's conclusion that SCONOx does require testing on larger facilities before it can be offered as part of its package for such plants supports the applicant's concerns about unresolved technical issues in the application of SCONOx to its facility.

In conclusion, EPA believes the operational uncertainties with regard to the scale up of the technology and the lack of demonstrated experience with the proposed design show that SCONOx is not yet an available technology. Nevertheless, EPA believes that SCONOx, as a non-ammonia control system, does have great potential and any future BACT determinations on combined-cycle gas turbines will need to consider whether, at that time, the current technical issues have been adequately resolved.

B. Particulate Matter (PM and PM-10)

As noted above, the proposed AES facility is subject to BACT requirements for PM emissions. The primary source of PM emissions from the proposed AES facility is the combustion of fuel in the turbines. Small quantities of PM emissions are also emitted from the cooling tower. In general, there are several types of add-on control technologies that can be utilized to control PM emissions. Such add-on PM control technologies include; fabric filters, wet scrubbers and electrostatic precipitators. PM emissions may also be controlled by combusting clean fuels. AES has proposed that the combustion of natural gas, as the primary fuel, and low sulfur distillate fuel, as the backup fuel, be regarded as BACT for PM. Specifically, AES proposed PM emission limits of 0.004 lb/MMBTU on natural gas and 0.02 lb/MMBTU on fuel oil. The proposed PM emission levels are significantly below the performance requirements of Part Env-A 2003.08 *Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985*, which would limit PM emissions to 0.1 lb/MM BTU.

It has been concluded that the combustion of natural gas, as the primary fuel, and low sulfur diesel fuel, as the backup fuel, is considered BACT for the combustion turbines. It was concluded that add-on controls would not be feasible due to high exhaust flows and very low concentrations of PM in the exhaust stream. EPA is not aware of any combustion turbine facility that has installed add-on PM controls, such as a fabric filter, wet scrubber or electrostatic precipitator. This determination is consistent with recent determinations made for the following plants listed in Table 2:

Table 2. Recently Proposed Combined Cycle Plants in New England

Facility	Location	Permit Status	Date
Gorham Energy	Gorham, ME	Issued	Dec. 1998
Westbrook Energy	Westbrook, ME	Issued	Dec. 1998
Blackstone Energy	Blackstone, MA	Proposed	March 1999
Milford El-Paso	Milford, CT	Proposed	Dec. 1998

PM emissions from the cooling tower are generated by the presence of small solid particles within the circulating water of the cooling tower. A small percentage of the circulating water exists the cooling tower and is commonly referred to as "drift". AES proposed and EPA has concluded that the use of high efficiency drift eliminators would be considered BACT for the proposed cooling tower. High efficiency drift eliminators consist of baffles that remove water droplets from the exhaust stream of the cooling tower. The removal of the water droplets from the exhaust stream will minimize PM emissions from the cooling tower. Drift from the cooling towers will be limited to 0.0005% of the circulating water.

C. Sulfur Dioxide and H_2SO_4

As noted above, the proposed AES facility is subject to BACT requirements for SO_2 and H_2SO_4. SO_2 emissions from the proposed AES facility is the result of oxidation (combustion) of sulfur contained in the fuel. A percentage of sulfur in the fuel is further oxidized to SO_3, which in turn reacts with moisture to form H_2SO_4 or sulfuric acid mist. The most practical and effective way to limit SO_2 and H_2SO_4 emissions is by minimizing the sulfur content of fuel. Subpart GG limits the sulfur content of the fuels combusted in new combustion turbines to a maximum sulfur content of 0.8 percent by weight. While natural gas is inherently low in sulfur content, fuel oil in New Hampshire may contain up to 2 percent by weight of sulfur. AES has proposed limiting the sulfur content of natural gas and fuel oil to 0.8 grain/100 SCF (less than 0.01 percent by weight) and 0.05 percent sulfur by weight, respectively. The sulfur levels proposed by AES are well below sulfur content limits of Subpart GG.

EPA has concluded that the combustion of natural gas, as the primary fuel, and low sulfur distillate fuel, as the backup fuel, is considered BACT for the AES facility. This determination is consistent with recent BACT determinations made for similar facilities.

D. Carbon Monoxide (CO)

As noted above, the proposed AES facility is subject to BACT requirements for CO. Emissions of CO from the proposed AES facility is the result of incomplete combustion of fuel in the turbines. Emissions of CO can be minimized by ensuring adequate fuel residence time and high combustion temperatures within the combustion zone. However, controlling CO in this manner will have the negative impact of increasing NO_x formation. Water and steam injection into the combustion zone or the use of Dry-Low NO_x combustors can be utilized to minimize NO_x formation while maintaining low levels of CO formation. Other than minimizing CO formation from the combustion process, the only other option is to reduce CO emissions by means of an add-on CO Oxidation Catalyst control system.

EPA would note that a comment was received that indicated that the use of SCONOx technology could also reduce CO and other emissions from the facility.

In accordance with PSD regulations, other considerations sch as energy, economic, and environmental impacts of a particular control option may be considered in determining BACT for a particular source. As part of the application, AES reviewed the economic impact of installing either an 80% or 90% CO Catalyst Reduction system. An economic analysis of air pollution control equipment is generally measured in terms of dollars per ton of pollutant removed, thus providing a consistent means of determining the cost of a control option. The economic analysis performed by AES estimated that the cost of the 80% CO Catalyst Reduction System would be $1,956/ton CO removed and the cost of the 90% CO Catalyst Reduction System would be $2,207/ton CO removed. AES has stated that the cost associated with either CO Reduction System would be cost prohibitive and therefore should not be considered BACT for this project. In addition, AES has identified several energy and environmental impacts associated with the installation of a CO catalyst system that should be considered in determining whether such a CO Catalyst System should be considered BACT.

The installation of a CO oxidation catalyst could increase PM and H_2SO_4 emissions oil. Further information about this limit can be found in Section VIII.A of this determination.

VIII. Nonattainment Control Technology Review:

This portion of this Final Determination has been prepared by DES as noted in Section III.

A. Nitrogen Oxides (NOx)

State and Federal regulations and policies define LAER as the most stringent emission limitation contained in the implementation plan of any State for a particular source category or the most stringent emission limitation which is achieved in practice by a particular source category, whichever is more stringent. As a new source seeking to locate in a Nonattainment area AES is required to install LAER for NOx.

As noted above, the proposed AES facility must meet LAER requirements for emissions of NO_x. Emissions of NO_x from the combustion process is the result of the oxidation of nitrogen contained either in the fuel ('fuel NO_x") or combustion air ("thermal NO_x"). Since fuel bound nitrogen in natural gas (the primary fuel for the AES facility) is negligible, reducing NO_x from the combustion process must primarily focus on limiting the formation of thermal NO_x. The utilization of dry Low NO_x combustors ("LNBs") eliminates high flame temperatures and minimizes thermal NO_x formation and is considered state-of-art combustion technology for combustion turbines. AES has proposed the installation of dry LNBs as an initial step towards meeting the LAER requirement for NO_x. AES has also proposed using water injection to limit NO_x formation during oil firing. AES has estimated that NO_x levels prior to the SCR system would be 25 ppmvd on natural gas and 42 ppmvd on fuel oil. In addition to using the above technology, AES has also evaluated several add-on control technologies to further reduce NO_x emissions. The add-on control technologies analyzed by AES included Selective Catalytic Reduction (SCR) and SCONOx, a relatively new NO_x control technology.

SCR systems have been commercially available for a number of years and have been widely used in most recent NO_x LAER determinations for combustion turbines. SCR systems require the injection of ammonia in the turbine exhaust which in turn reacts with nitrogen oxides, in the presence of a catalyst, to form nitrogen and water. Early LAER determinations for combustion turbines using SCR systems where typically 9 ppm or higher. More recent LAER determinations have been in the 3.5 ppm range with various averaging times (most determinations in the Northeast have been based on a one-hour averaging time). AES has proposed the installation of an SCR system in conjunction with dry LNBs during gas firing and SCR with water injection during oil firing as LAER for this project. Specifically, AES has proposed a NO_x limit of 3.5 ppmvd (at 15 % O_2) on natural gas and 9.0 ppm (at 15 % O_2) on fuel oil as LAER for this project.

As stated above, AES also considered the use of SCONOx technology as part of the NO_x LAER analysis. SCONOx is an oxidation catalyst technology marketed by Goal Line Technologies. SCONOX oxidizes NO to NO_2 and CO to CO_2. The NO_2 is subsequently absorbed onto a potassium carbonate absorber. The absorber must periodically be regenerated by taking a portion of the system offline and utilizing a regeneration process. The use of the SCONOX technology has two potential benefits over traditional SCR systems. First, the SCONOX technology requires no ammonia to achieve NO_x reductions, thereby eliminating ammonia emissions. Secondly, there exists the potential for lower NO_x emissions, as NO_x emissions as low as 2.5 ppm have reportedly been achieved. AES has presented a number of reasons why it believes that the SCONOX technology should not be considered LAER for this project. The reasons noted by AES included: 1) lack of independent demonstration; 2) lack of demonstration during distillate oil firing; 3) scale-up concerns; 4) concerns over reliability of moving parts, such a louvers; 5) concerns with potential catalyst degradation; 6) concerns over sulfur removal requirements; and 7) concerns over catalyst regeneration methods.

DES notes that there has been conflicting opinions about the commercial availability of SCONOx technology for plants of the size and nature of AES. In a January 18, 1999 letter to Connecticut DEP, ABB Power Generation, the licensee of the SCONOx technology, concluded that the SCONOx technology was not commercially available for this type of application at this time. However, Goal Line Technologies, the proprietor of the SCONOx technology, has disputed this claim. In making this determination, DES is not excluding the use of SCONOx technology as a mechanism to achieving the LAER determination. In fact, DES would encourage the use of a non-ammonia based NOx control system, such as SCONOx.

DES received comments that DES failed to consider two other NOx control technologies, namely, XONON and Ozone Injection in making its NOx LAER determination. The XONON technology is under development by General Electric and Catalytica, Inc. The technology consists of combusting fuel in the presence of a catalyst, thus allowing for a lower flame temperature. This lower flame temperature minimizes thermal NOx formation. Similar to SCONOX, the XONON technology achieves low NOx emissions without the need for ammonia injection, thereby eliminating ammonia emissions. At the time DES made its Preliminary Determination, DES was aware of this technology, however the technology was dismissed based upon information DES had obtained at the

NECA conference in September 1998. Based on statements made at the conference by a representative of XONON, DES concluded that the technology was not commercially available at this time for plants similar in size and nature of AES. DES recognizes that this finding should have been noted in the Preliminary Determination.

In response to comments, DES has conducted a follow up review of the XONON technology. Based on this review DES still concludes that this technology is not commercially available at this time for facilities of the size and nature of AES. This conclusion is based on discussions DES had with a representative of Catalytica, Inc. DES was informed that there only exists a single small turbine (1.5MW) in Monterey, CA that is currently operating with the XONON technology. The system has operated approximately 1200 hours and routinely operates at less than 3 ppm during "normal operations". Commercial operation of the Monterey Turbine is expected to begin by June 1, 1999. Although it appears that the technology is promising, the technology is not demonstrated in practice nor is it commercially available for turbine projects the size and nature of AES.

DES has also conducted further research on the Ozone Injection technology. The Ozone Injection system is a joint program by Cannon Technology, Inc ("Cannon") and BOC Gases ("BOC"). This technology is being developed and commercialized as the LTO System for NOx Control by Cannon for industrial applications and by BOC as LoTOX System for NOx Reductions in larger industrial and utility applications. This technology uses oxygen or air to produce ozone in an ozone generator. The ozone is injected into the flue gases where a chemical reaction with the flue gas NOx takes place. The NOx is converted to N_2O_5, which is highly soluble in water. The N_2O_5 is removed from the flue where it is neutralized in a wet scrubber. It is the understanding of DES that this technology has undergone several demonstration projects including: A slip stream test conducted on flue gas stream from a coal-fired boiler at Duquesne Light's Elrama Power Station and a 400 HP Cleaver Brooks natural gas-fired boiler at Alt Dena Dairy in Industry, CA. Based on discussions with representatives of Cannon and BOC, DES has concluded that although the Ozone Injection Technology is theoretically practical and demonstrated on a limited scale, the technology is not demonstrated in practice on a plant the size and nature of AES.

Recently there has been increased focus on whether SCR systems can achieve ultra-low NO_x emission levels (less than 3.5 ppmvd). It has been generally indicated that NO_x emission levels lower than 3.5 ppmvd can be achieved with SCR technology. In order to achieve these lower NO_x levels, additional catalyst may be need and an enhanced ammonia injection system may be required to ensure proper NO_x/NH_3 molar ratios.

In the Preliminary Determination for AES, DES had concluded that LAER for this project will be a NO_x limit of 2.5 ppmvd @ 15 % O_2 (3 hour rolling basis) on natural gas and 9.0 ppmvd @ 15 % O_2 (1 hour rolling basis) on fuel oil. In making this determination DES took into consideration that several other similar combustion turbine facilities had been proposed in the Northeast at this NO_x emission level. In addition, the Maine Department of Environmental Protection had recently issued permits for the Gorham Energy and the Westbrook Power facilities at a NO_x limit of 2.5 ppmvd @ 15 % O_2 (3 hour rolling average) on natural gas.

During the public comment period, DES received comments from EPA and others on the above 2.5 ppmvd NOx limitation. In summary, DES received comments suggesting that the NOx LAER limit should be lowered to 2 ppmvd for natural gas firing. The comments were in part based on the pending issuance of a permit to the PDC-El Paso Milford ("Milford") facility in Connecticut. In the proposed permit to Milford, a NOx limit of 2.0 ppmvd @ 15 % O2 (3 hour basis) has been proposed. As of the writing of this Final Determination, the permit to Milford facility has not been issued. In addition, on March 3, 1999, the Massachusetts Department of Environmental Protection ("Mass DEP") issued its preliminary findings on the ANP Blackstone Energy Company. The Blackstone plant is similar in size and nature to the AES Facility. The Mass DEP concluded that LAER in this case would be an emission limit of 2.0 ppmvd @ 15 % O2. DES would note that the proposed Blackstone permit has not gone through public review and the permit has not been issued. DES further notes that the proposed 2.5 ppmvd limit is as stringent as any NOx permit limitation in a permit issued to a facility similar to AES.

B. Ammonia

AES has proposed the use of a SCR system to control NO_x emissions. The SCR system will utilize ammonia as a reagent to reduce NO_x emission from the turbines to nitrogen (N_2), which is the major component of ambient air. In order to maximize NO_x reductions, the molar ratio of ammonia to NO_x must exceed the stoichiometric ratio needed to fully consume the ammonia. The unreacted ammonia is commonly referred to as "ammonia slip" and would be emitted through the exhaust stacks for the turbines. Ammonia slip is generally very low for new units, however the slip rate will generally increase over time. This increase of slip overtime occurs as portions of the catalyst become deactivated due to chemical and physical poisoning. In order to compensate for the deactivation of portions of the catalyst, the amount on ammonia needed to maintain high levels of NO_x reductions must be increased.

In the Preliminary Determination for AES, DES proposed an ammonia slip rate of

10 ppm. DES noted that it expected that ammonia slip levels would be significantly below the proposed limit of 10 ppm during the initial period of operation. Based on discussions DES had with a representative of Peerless Mfg (a supplier of SCR equipment), DES would expect that ammonia slip rates would be in the 2 to 3 ppm range for at least the first three years of operation of this facility. DES has further concluded that the 10 ppm limitation was acceptable for the first year of commercial operation. At the conclusion of one year of operation DES proposed that it would review the ammonia slip data and re-evaluate this limitation. DES further noted that the 10 ppm limit is consistent with permits recently issued for similar combined cycle gas plants.

DES received a number of comments regarding the proposed ammonia slip level of 10 ppm. One comment received on the Preliminary Determination questioned whether DES had undertaken an adequate study of whether the proposed 10 ppm limit was protective of public health. The comment compared the 10 ppm slip limit to several Health Effect Data Thresholds as noted in the Table 3 below:

Table 3. Ammonia Standards

Health Effect Data Thresholds	Threshold in Parts Per Million (PPM)
EPA Chronic RfC	0.14 ppm
CAPCOA Acute REL	3.00 ppm
CAPCOA Chronic REL	0.14 ppm
NIOSH	50 ppm for 5 minutes
OSHA	35 ppm of 15 minutes

DES notes that comparing the 10 ppm slip rate to the above thresholds is inappropriate as air dispersion effects are not considered in such a comparison. The ambient air impacts of ammonia slip have were evaluated by DES and it was determined that the worst case impact for ammonia was 25 ug/m3 on a 24 hour basis, which is equivalent to 0.035 ppm, and 0.6 ug/m3 on an annual basis, which is equivalent to 0.0008 ppm. DES again concludes that the 10 ppm slip rate is in compliance with the Ambient Air Limits ("AAL") established under Env-A 1400, *Regulated Toxic Air Pollutants.* As noted in Section XX the AALs for ammonia are 100 ug/m3, which is equivalent to 0.14 ppm, on both a 24 hour and annual basis.

C. Volatile Organic Compounds (VOCs)

The proposed AES facility will not be a major source of VOCs, therefore the facility is not subject to LAER or offset requirements for VOC emissions. AES anticipates that the proposed combustion turbines will meet a VOC emission rate of 1 ppmvd (0.0013 lb/MM BTU) during natural gas firing and 7 ppmvd (0.0095 lb/MM BTU) during fuel oil firing. DES will require that AES perform EPA Method stack tests to verify VOC emissions from the turbines.

IX. Summary Table of Proposed BACT/LAER Limitations

Table 4. below provides a summary of proposed BACT/LAER limitations:

Table 4. Summary of Proposed BACT/LAER Limitations

Pollutant	Limitation	Technology BACT/LAER.	Averaging Time
Nitrogen Oxides (Gas Firing)	2.5 ppmvd @ 15 % O_2	Low NOx Burner with SCR LAER	3 hour block average
Nitrogen Oxides (Oil Firing)	9.0 ppmvd @ 15 % O_2	Low NOx Burner with Water Injection and SCR LAER	1 hour block average
Sulfur Dioxide (Gas Firing)	0.0023 lb/MM BTU	Low Sulfur Fuels BACT	3 hour rolling
Sulfur Dioxide (Oil Firing)	0.052 lb/MM BTU	Low Sulfur Fuels BACT	3 hour rolling
Carbon Monoxide (Gas Firing) @ All Loads	15 ppmvd @ 15 % O_2	Low NOx Burner with Good Combustion Practices BACT	1 hour block average
Carbon Monoxide (Oil Firing) @ All Loads	50 ppmvd @ 15 % O_2	Low NOx Burner with Good Combustion Practices BACT	1 hour block average

Pollutant	Limitation	Technology BACT/LAER	Averaging Time
TSP/PM-10 (Gas Firing)	0.004 lb/MM BTU	Low Sulfur Fuels BACT	1 hour block average
TSP/PM-10 (Oil Firing)	0.020 lb/MM BTU	Low Sulfur Fuels BACT	1 hour block average
Volatile Organic Compounds (Natural Gas Firing)	0.0013 lb/MM BTU	Good Combustion Practices N/A	1 hour block average
Volatile Organic Compounds (Fuel Oil Firing)	0.0095 lb/MM BTU	Good Combustion Practices N/A	1 hour block average
Opacity	20 %	Good Combustion Practices N/A	6 minute block average
Ammonia	10 ppmvd @ 15 % O_2	N/A	24 hour block average

X. AIR QUALITY IMPACT ANALYSIS

A. Modeling Overview

An ambient air quality impact analysis was performed to assess predicted air quality concentrations from the AES facility against applicable state and federal standards and guidelines. Standard modeling procedures were followed in the evaluation, using EPA-approved models and procedures. First, modeling was performed in all three terrain regimes (simple, intermediate and complex) to determine the worst-case operating load condition. This worst-case load, along with all other load conditions, were considered in the modeling to determine whether the source is expected to produce significant impacts. For those pollutants shown to be significant, namely SO_2 and PM10, refined modeling incorporating impacts from additional sources in the area was performed using the worst-case load from the significant impact area analysis. The proposed AES facility was shown not to cause or contribute to violations of Ambient Air Quality Standards (AAQS) or PSD increments. Other analyses as required by state and federal regulations were also done, including a cavity analysis, evaluation of Class I area impacts, a toxic air pollutant impact assessment and additional PSD analyses. All dispersion modeling was performed assuming 720 hours per year on oil backup and 8040 hours per year on natural gas (worst-case condition).

B. Model Input Data

Modeling for simple/intermediate terrain was performed using the ISCST3 dispersion model, version 98356. The model was run with regulatory defaults for over 2300 receptors located in both the nearfield to address downwash and local impacts and at distances further downwind. Rural dispersion coefficients were used based on EPA guidance. For complex/intermediate terrain as well as for the cavity analysis, the SCREEN3 model (version 96043) was run, again using regulatory default options. In performing modeling above stack top, the COMPLEX I VALLEY mode option was utilized to give worst-case impacts. All modeling was performed in accordance with all applicable DES and EPA guidelines.

A valid 5-year hourly meteorological database was used in the ISCST3 refined modeling. The surface wind data were collected at a height of 20 feet at the National Weather Service (NWS) office in Concord, New Hampshire during the period 1986-1990. The upper air data were taken from the nearest NWS upper air station at Portland, Maine for the same time period.

Stack parameters and emission rates for the various combustion turbine load conditions are listed in Table 5 for natural gas and in Table 6 for distillate oil (0.05% sulfur). Since the two stacks are below GEP height, the modeling analysis accounted for the potential for building downwash wake effects on emissions from the stacks. The BPIP program was used in the determination of GEP stack height and direction specific building dimensions.

The input data used in the modeling of the cooling tower are presented in Table 7. For the criteria pollutant analysis, the cooling tower drift was treated as PM10 and was modeled in conjunction with the PM10 emissions from the turbine stacks. The cooling tower was also modeled for its potential effects on local visibility and for emissions of toxic air pollutants regulated by New Hampshire under Env-A 1400 of the *Rules Governing the Control of Air Pollution*.

Table 5
Combustion Turbine Emissions and Stack Parameters (for each turbine)
Natural Gas

Turbine Load	%	100			85			75		
Ambient Temp	°F	0	50	100	0	50	100	0	50	100
Stack Height	ft	132	132	132	132	132	132	132	132	132
Stack Diam.	ft	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Base Elevation	ft	300	300	300	300	300	300	300	300	300
Exit Temp	°K	361	361	361	361	361	361	361	361	361
Gas Velocity	m/s	20.6	18.8	17.0	18.4	16.9	15.3	16.6	15.3	14.4
NOx	g/s	4.7	4.2	3.7	4.2	3.6	3.4	3.8	3.4	3.1
CO	g/s	12.2	10.9	9.7	10.9	9.5	8.8	9.9	8.9	8.0
PM10	g/s	1.4	1.3	1.1	1.3	1.1	1.0	1.2	1.1	1.0
SO_2	g/s	0.8	0.7	0.7	0.7	0.6	0.6	0.7	0.6	0.5

Table 6
Combustion Turbine Emissions and Stack Parameters (for each turbine)
Distillate Oil

Turbine Load	%	100		95	
Ambient Temp	°F	0	32	0	32
Stack Height	ft	132	132	132	132
Stack Diam.	ft	20.7	20.7	20.7	20.7
Base Elevation	ft	300	300	300	300
Exit Temp	°K	389	389	389	389
Gas Velocity	m/s	23.0	21.7	22.9	21.6

NOx	g/s	12.5	11.6	11.9	11.1
CO	g/s	42.1	39.2	40.2	37.4
PM10	g/s	7.1	6.6	6.8	6.3
SO_2	g/s	18.6	17.3	17.8	16.5
Pb	g/s	0.02	0.02	0.02	0.02

Table 7
Cooling Tower Exhaust Characteristics (per cell)

Stack Height	61 ft
Cell Diameter	32 ft
Base Elevation	291 ft
Exit Temp	284 °K
Exit Velocity	8.7 m/s
Number of Cells	12
PM10	0.014 g/s

C. Single-Source Criteria Pollutant Impact Analysis

Using the input parameters and modeling procedures described above, the dispersion modeling analysis predicted significant impacts for SO_2 for the 3-hour and 24-hour averaging periods and for PM10 for the 24-hour and annual averaging periods (see Table 8 below). These impacts were predicted for the facility when burning oil as a backup fuel. Both NO_2 and CO were shown to have insignificant impacts while maximum lead impacts were predicted to be several times below the AAQS. The worst-case load condition was determined to be 100% at an ambient temperature of 32° F and this condition was used to determine significant impact areas as well as compliance with AAQS and increments.

Table 9 presents the facility's impacts in comparison to PSD Class II increment levels and AAQS for the significant pollutants. The impacts for the proposed source alone are predicted to be in compliance with all AAQS and Class II increments.

Table 8
Single-Source Maximum Impacts
Compared to Significant Impact Levels

Pollutant	Avg. Time	Maximum Conc. (ug/m³)	Significant Impact Level (ug/m³)
SO_2	Annual	0.4	1
	24-Hour	36.0	5
	3-Hour	122.8	25
PM10	Annual	4.9	1
	24-Hour	19.4	5
NO_2	Annual	0.6	1
CO	8-Hour	182.4	500
	1-Hour	734.3	2000

Table 9
Single-Source Maximum Impacts
Compared to Ambient Air Quality Standards

Pollutant	Avg. Time	Maximum Conc. (ug/m³)	Class II Increm. (ug/m³)	AAQS (ug/m³)
SO_2	Annual	0.4	20	80
	24-Hour	36.0	91	365
	3-Hour	122.8	512	1300
PM10	Annual	4.9	17	50
	24-Hour	19.4	30	150

The maximum short-term impacts (with the exception of PM10) were predicted in simple terrain using the ISCST3 model and were associated with building downwash. The maximum PM10 impacts were predicted to occur in the cavity region (see below section for explanation). The maximum annual impacts were predicted to occur in complex and intermediate terrain using the SCREEN3 model (VALLEY screening mode), again with the exception of PM10.

1. *Cavity Analysis*

An analysis was performed to determine the potential for impacts within the cavity region of the buildings on-site. The analysis determined that the main buildings (the generation building and the heat recovery steam generator building) did not cause any impacts in the cavity region with regard to the combustion turbine stacks, though these structures, as well as the cooling tower structure, did produce cavity impacts for the cooling tower PM10 plume. These impacts, when added to the impacts from the combustion turbines and to the contributions from other sources, were higher than those predicted in the other terrain regimes but did not produce any exceedences of air quality standards. The cavity analysis was performed using the SCREEN3 model with the regulatory Brode default cavity algorithm. The cavity length corresponding to the maximum predicted PM10 concentration was 69 feet.

C. <u>Class I Area Analysis</u>

Under the Prevention of Significant Deterioration provisions of the Clean Air Act, certain national parks and wilderness areas have been given special protection against adverse air quality impacts. To assess these impacts, DES, in conjunction with the National Forest Service (NFS), has developed a procedure which applies to all applicants for PSD permits. This procedure looks at the source's impacts on Class I area increment, visibility, sulfur deposition, nitrogen deposition, acid neutralizing capacity and ozone formation, using criteria established by the NFS. The modeling requirements follow recommendations made in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility*. For this project, impacts were evaluated at receptors located in the Great Gulf and Dry River Wilderness Class I areas in New Hampshire (located more than 130 km to the north) and the Lye Brook Class I area in Vermont (located approximately 130 km to the west-northwest).

Initial modeling by the applicant using ISCST3 showed impacts well below the Class I increments, though above the significant impact level for short-term SO_2 when the facility is operating on distillate oil backup. To address this issue, AES performed a more refined, single-source modeling analysis using the CALPUFF model to better simulate the long distance transport of the plume to the Class I areas.

The CALPUFF modeling system used in this analysis consisted of the CALPUFF transport and dispersion model (Version 5.0, Level 990130), the CALMET diagnostic meteorological model

(Version 5.0, Level 990130) and the CALPOST post-processor (Version 5.0, Level 981230). Since that time, a minor revision to the CALPUFF programs was made and the current version is now Version 5, Level 990228. The modification involved a refinement of the algorithm which deals with dispersion in convergent flows such as occurs in terrain channeling and seabreeze circulations. This modification was not expected to result in a significant change to the results from the earlier version of CALPUFF. To verify this, comparative model runs were made with the two CALPUFF versions for the period when the maximum SO_2 impacts were predicted. The modeling with the current model version showed essentially identical results.

An "initial guess" CALMET wind field was developed using the MM4 EPA database from 1990. Since 1990 meteorological data were available, the CALMET and CALPUFF models were run for that year. Additional meteorological data were used to derive the final CALMET wind fields, which included 12 surface stations, 42 precipitation stations, 3 upper air stations and 1 buoy. Ozone measurements made at 11 monitoring locations in northern New England were used to provide hourly background ozone concentrations during the ozone season. This information is used in CALPUFF to compute chemical transformation rates of NOx to HNO_3 and NO_3.

The CALPUFF computational domain included southern and central parts of New Hampshire and Vermont and extended into the states of Maine, New York and Massachusetts. The northern boundary of the domain is about 35 km north of the Great Gulf Wilderness area and about the same distance west of the Lye Brook Wilderness area, with the southwest corner of the domain lying near Albany, New York. The domain extends 250 km by 220 km in the east-west and north-south directions, respectively. A horizontal grid resolution of 2 km was used. Ten vertical layers were modeled at heights of 0-20 m, 20-40 m, 40-80 m, 80-160 m, 160-300 m, 300-600 m, 600-1000 m, 1000-1500 m, 1500-2200 m and 2200-3000 m.

USGS land use data at a resolution of 200 m was used to determine the fractional land use category information for each 1 km grid cell. For each cell, the albedo, Bowen ratio, roughness length and leaf area index were computed as a weighted average based on fractional land use. The grid cell elevations were taken from USGS digital elevation models (DEMs).

The maximum impacts of the proposed AES facility on the Class I areas are shown below in Table 10. All impacts using the CALPUFF model are shown to be below the significant impact levels.

Table 10
Maximum Increment Impacts in Class I Areas

Pollutant	Avg. Time	Contrib.	Increment	Significant Impact Level (ug/m^3)
SO_2	Annual	0.005	2	0.08
	24-Hour	0.17	5	0.2
	3-Hour	0.61	25	1.0
PM10	Annual	0.003	4	0.16
	24-Hour	0.07	8	0.32
NO_2	Annual	0.004	2.5	0.1

For the other impact criteria established by the NFS, known collectively as Air Quality Related Values (AQRVs), the proposed facility has demonstrated impacts well below the minimum threshold levels and is predicted to have little probable effect on these values. One important part of the AQRV analysis is the assessment of the degradation of visibility in the Class I areas due to the proposed facility. To determine the effects of the AES facility on visibility, the EPA VISCREEN model was used (Version 1.01). A Level-I assessment was performed and it was found that impacts were well below the thresholds of plume contrast and perceptibility.

D. Interactive-Source Criteria Pollutant Impact Analysis

In accordance with DES guidance, an interactive modeling analysis must be performed and include existing, nearby major sources for all pollutants and averaging periods which have been shown to be significant. The results of this analysis are compared to AAQS, once ambient background is considered, as well as Class II increment levels which apply to all new and modified permitted sources. Based on the applicant's significant impact area analysis, the following sources were included in the interactive modeling.

- Anheuser Busch - Merrimack
- Continental Paving - Londonderry/Hudson
- Elliott Hospital - Manchester
- Nyltech - Manchester
- Velcro USA - Manchester

These sources were modeled in conjunction with the proposed AES facility at their permitted SO_2 and PM10 emission rates. No gas pipeline compressor stations were modeled since none are anticipated for the project. As in the single-source analysis, the same 5-year meteorological data set was used for the interactive ISCST3 modeling. To calculate plume interaction in complex terrain, ISCST3 was run for complex terrain in an equivalent VALLEY screening mode using F stability with a wind speed of 2.5 m/sec. A total of 36 wind directions at 10° intervals were used.

The maximum impacts for the pollutants and averaging periods for which the AES facility is significant are shown below in Table 11 and Table 12. The total impacts presented are at receptors within AES' significant impact area. The tables reflect the total air quality impacts in the area, assuming the AES facility is operating under worst-case conditions. All impacts are predicted to be below the allowable state and federal limits and show that the proposed source does not cause or contribute to any air quality violations.

Table 11
Interactive Source Maximum Impacts Compared to AAQS

Pollutant	Avg. Time	Contrib.	Bckg.	Impact	AAQS	Pass/Fail
SO_2	24-Hour	169.5	96	265.5	365	PASS
	3-Hour	695.7	207	902.7	1300	PASS
PM10	Annual	5.1 (a)	18	23.1	50	PASS
	24-Hour	22.3 (a)	34	56.3	150	PASS

(a) maximum PM10 impacts were predicted in the cavity region.

Table 12
Interactive Source Maximum Impacts Compared to Class II Increment

Pollutant	Avg. Time	Contrib.	Increment	Pass/Fail
SO_2	24-Hour	47.4	91	PASS
	3-Hour	120.4	512	PASS
PM10	Annual	4.9 (a)	17	PASS
	24-Hour	19.5 (a)	30	PASS

(a) maximum PM10 impacts were predicted in the cavity region.

The background (Bckg.) air quality data shown in Table 11 was taken from Manchester from 1996-1998 and has been updated since the application submittal. The Manchester monitoring site was determined to be representative of the air quality in the project area and the actual concentrations are believed to be conservative compared to the project site.

E. Additional PSD Impact Analyses

1. *Local Visibility Impairment*

The potential effects of the proposed project on visibility in the immediate area surrounding the site were assessed through a detailed modeling analysis. Initially the SACTI model was used to estimate parameters such as amount of fogging and icing, plume height, plume length and radius of the plume. The model was run for a saturated plume and only addressed the effects of the cooling tower. A further analysis was performed with the CALPUFF model using a fogging algorithm developed by the consultant in order to evaluate the potential impacts of an abated plume. The technology that produces this type of plume combines evaporative cooling with tube heat exchangers which reduce the relative humidity of the air leaving the tower. This plume abatement system greatly reduces the visible plume and will be employed during the cooler weather when the potential for a visible plume is greatest. The modeling incorporating plume abatement technology was done for both the cooling tower and stack plumes and showed minimal hours of fogging and a limited plume length.

The surface meteorological data used in the SACTI modeling were taken from Manchester, New Hampshire in 1986, with nighttime hours supplemented by Concord. Portland upper air data were used for the same time period. A different data set was used compared to the ISCST3 modeling since humidity variables were required for SACTI.

2. *Impacts Due to Growth and Construction*

There are not expected to be significant impacts from the construction phase of this project due to use of best management practices on site and also due to the fact that construction will be temporary and short-lived. The plant expects to hire approximately 35 new employees which will largely come from the available local work force, therefore residential growth is not expected to be significant. Once constructed, the proposed facility will consume little in terms of raw materials and supplies so construction of new industries and businesses will not likely be needed.

It is possible that the facility, once in operation, will attract other businesses and industrial facilities to the Londonderry Ecological Park, which is where the AES plant will be located. Any new facility which emits air pollutants is subject to DES' *Rules Governing the Control of Air Pollution* and, depending on which sections of the Rules are applicable, may need to be modeled to demonstrate compliance with the appropriate standards. This modeling may include AES and other nearby sources, again depending on the applicable regulations, so any future growth will be accounted for.

3. *Soils and Vegetation*

A quantitative analysis was performed to evaluate the effects of the proposed facility on soils and sensitive vegetation, using criteria established by EPA as contained in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. As stated in the EPA guidance document, AAQS are protective against vegetative damage, except possibly for the 3-hour and annual SO_2 standards. Since AAQS, and the lower Class II increment levels, are not exceeded by the proposed AES facility, there are not expected to be any adverse effects on vegetation due to the plant's impacts.

For the 3-hour and annual SO_2 screening criteria, the modeled single-source impacts are seen to be well below the screening levels, though one of the values appears elevated due to the relatively large contribution of interactive sources (3-hour SO_2). At the highest impact receptor, modeling shows the AES facility to have only a minor overall contribution.

F. <u>Toxic Air Pollutant Evaluation</u>

Chapter Env-A 1400 of the Rules requires an evaluation of the potential impacts of toxic air pollutants. For this facility, it was determined that air toxics emissions are possible due to ammonia slip from the SCR system on the combustion turbine stacks and from the dissolved solids and volatile compounds in the recirculating water of the cooling tower due to the use of treated wastewater effluent. All impacts were compared against New Hampshire Ambient Air Limits (AALs) for both 24-hour and annual averaging periods.

1. *Ammonia Slip*

The maximum impacts due to ammonia slip from the combustion turbine are shown below in Table 13. These values are based on an assumed slip rate of 10 ppm and may result from ammonia which does not completely react with NOx in the catalytic reduction process. Emissions of ammonia nitrate and ammonia sulfate are possible as by-products of this process but these compounds are not regulated by DES under Chapter Env-A 1400.

Table 13
Maximum Impacts Due to Ammonia Slip

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL
Ammonia	25.0	100	0.6	100

2. *Cooling Tower Toxic Air Pollutant Impacts*

Minor impacts of toxic air pollutants are anticipated due to drift from the cooling tower system. Emission rates of both metals and volatile compounds were determined from test data, water treatment plant effluent limits and reported values from a study performed for a similar facility in Maryland. These impacts are shown below in Tables 14, 15 and 16 for metals and volatiles respectively. The maximum predicted impacts are no more than 25% of the AAL for any compound.

Table 14
Maximum Metals Impacts From Cooling Tower

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL
Ammonia	0.234	100	0.059	100
Aluminum	0.008	50	0.002	34
Chromium	< 0.001	0.179	< 0.001	0.119
Copper	< 0.001	0.714	< 0.001	0.476
Cyanide (total)	< 0.001	18	< 0.001	12
Iron	0.010	25	0.002	17
Lead	< 0.001	0.179	< 0.001	0.119
Mercury	< 0.001	0.30	< 0.001	0.30
Silver	< 0.001	0.05	< 0.001	0.034
Zinc	0.003	25	< 0.001	17

Table 15
Maximum Volatile Compounds Impacts From Cooling Tower

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL
Benzene	1.4	5.714	0.3	3.81
Carbon Disulfide	0.6	700	0.2	700
Chloroform	4.3	175	1.1	117
Dibutyl Phthalate	0.6	25	0.2	17
Dioctyl Phthalate	0.7	18	0.2	12
Tetrachloroethylene	5.7	607	1.4	405
Toluene	15.0	671	3.7	400
1,1,1Trichloroethane	16.1	277	4.0	184
Trichloroethylene	7.6	961	1.9	640
Trimethylbenzene	3.3	619	0.8	412

Table 16
Maximum Volatile Compounds Impacts From Cooling Tower

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL
Benzene	1.4	5.714	0.3	3.81
Carbon Disulfide	0.6	700	0.2	700
Chloroform	4.3	175	1.1	117
Dibutyl Phthalate	0.6	25	0.2	17
Dioctyl Phthalate	0.7	18	0.2	12
Tetrachloroethylene	5.7	607	1.4	405

Toluene	15.0	671	3.7	400
1,1,1Trichloroethane	16.1	277	4.0	184
Trichloroethylene	7.6	961	1.9	640
Trimethylbenzene	3.3	619	0.8	412

G. Fine Particulate Matter Analysis:

DES received several comments on potential impacts of fine particulate matter ($PM_{2.5}$) impacts from the AES Londonderry facility. DES has determined that an meaningful analysis of impacts of fine particulate matter ($PM_{2.5}$) was not possible for this project for a number of reasons. First, though $PM_{2.5}$ ambient air quality standards are in place, there is currently no EPA guidance on how to model this pollutant from individual point sources. Since much of $PM_{2.5}$ production is expected to come from secondary particle formation, it cannot be modeled as a non-reactive pollutant using traditional continuous release or puff models. It is expected that compliance determinations using the new $PM_{2.5}$ standard will be done on a regional modeling basis, similar to current efforts on ozone. Second, since $PM_{2.5}$ monitoring programs are in their infancy there is no way to establish a background for comparison to these standards. Significant impact levels have also not yet been established. Third, $PM_{2.5}$ emission factors are not yet available and little testing has been done on this pollutant, making establishing an accurate emission rate very difficult. For these reasons, we believe that a modeling analysis for this pollutant is not warranted or even possible at this time.

XI. Emissions Offset Requirements:

The AES Facility is subject to the NO_x emission offset requirement of non-attainment review. Since the proposed facility will be located in a serious non-attainment area for ozone, the emissions of NO_x must be offset at a ratio of 1.2 to 1.0. As such, AES must obtain 317 tons (264 tons multiplied by 1.2) of NO_x offsets. DES has determined that NO_x Budget Allowances held by AES may be utilized on a 1.0 to 1.0 ratio towards the offset requirements, however the overall offset ratio must remain at 1.2 to 1.0. DES has estimated that AES will be assigned approximately 110 tons of NO_x Budget Allowances from the NO_x budget set aside account established by the NO_x Budget Program. Therefore, the balance of the NO_x offset requirement is estimated to be approximately 207 tons (317 tons of offsets less 110 tons of allowances).

At this time, the balance of offsets will be obtained by AES from State-owned Discrete Emission Reductions ("DERs"). The State of New Hampshire obtained approximately 1,000 tons of DERs as part of an agreement signed between DES and Public Service Company of New Hampshire ("PSNH"). The DERs were generated at PSNH's Schiller Station in Portsmouth, New Hampshire and PSNH's Newington Station in Newington, New Hampshire. Both Schiller and Newington Stations are regulated by Env-A 1211, NOx RACT. In accordance with Env-A 1211 these facilities must meet certain NOx emission reduction standards. By achieving greater than required NOx emission reductions, these two facilities were able to generate the above referenced DERs.

VOLATILE ORGANICS, METHOD 8260B
MODIFIED LIST OF ANALYTES

Compound	Quantitation Limit (ug/L)	Compound	Quantitation Limit (ug/L)
Dichlorodifluoromethane	5	2-Hexanone	10
Chloromethane	5	1,3-Dichloropropane	5
Vinyl chloride	2	Tetrachloroethene	5
Bromomethane	5	Dibromochloromethane	5
Chloroethane	5	1,2-Dibromoethane	5
Trichlorofluoromethane	5	Chlorobenzene	5
Diethyl ether	5	1,1,1,2-Tetrachloroethane	5
Acetone	10	Ethylbenzene	5
1,1-Dichloroethene	5	m/p-Xylene	5
Methylene chloride	5	o-Xylene	5
Carbon disulfide	5	Styrene	5
Methyl-t-butylether (MTBE)	5	Bromoform	5
trans-1,2-Dichloroethene	5	Isopropylbenzene	5
1,1-Dichloroethane	5	1,1,2,2-Tetrachloroethane	5
2-Butanone	10	1,2,3-Trichloropropane	5
2,2-Dichloropropane	5	n-Propylbenzene	5
cis-1,2-Dichloroethene	5	Bromobenzene	5
Chloroform	5	1,3,5-Trimethylbenzene	5
Bromochloromethane	5	2-Chlorotoluene	5
Tetrahydrofuran (THF)	10	4-Chlorotoluene	5
1,1,1-Trichloroethane	5	tert-Butylbenzene	5
1,1-Dichloropropene	5	1,2,4-Trimethylbenzene	5
Carbon tetrachloride	5	sec-Butylbenzene	5
1,2-Dichloroethane	5	p-Isopropyltoluene	5
Benzene	5	1,3-Dichlorobenzene	5
Trichloroethene	5	1,4-Dichlorobenzene	5
1,2-Dichloropropane	5	n-Butylbenzene	5
Dichlorobromomethane	5	1,2-Dichlorobenzene	5
Dibromomethane	5	1,2-Dibromo-3-chloropropane	5
4-Methyl-2-pentanone	10	1,2,4-Trichlorobenzene	5
cis-1,3-Dichloropropene	5	Hexachlorobutadiene	5
Toluene	5	Naphthalene	5
trans-1,3-Dichloropropene	5	1,2,3-Trichlorobenzene	5
1,1,2-Trichloroethane	5		

Note: For chromatograms which exhibit non-target analytes, the top ten tentatively identified compounds (TICs) must be qualified and, if possible, quantitated. If there are no non-target analytes present in the chromatogram, this should be noted in the report narrative.

ATTACHMENT D-1

ADDITIONAL AIR QUALITY CONDITIONS

1. The Committee imposes the following modification to Attachment D "Temporary Permit and Prevention of Significant Deterioration Permit". By replacing Section XVIII (B) with the following Section:

XVIII(B) AES shall perform daily sampling for fecal coliform and escherichia coliform bacteria at the multimedia filter discharge and the cooling tower blowdown discharge.

2. The Committee adds to Section XVIII, Sections J and K to read as follows:

XVIII (J) AES shall perform weekly sampling of the effluent from the multimedia filter for volatile organic chemicals (VOCs) included on the attached table entitled "Volatile Organics, Method 8260B, Modified List of Analytes" to the quantitation limits specified in the table and from the cooling tower blowdown for the following metals: antimony, arsenic, cadmium, copper, chromium, lead, mercury, nickel, silver and zinc. Analysis for VOCs shall be performed by EPA Method 8260B or equal, as approved by the DES Laboratory Director. Within 30 days of AES receiving sampling results, AES shall report any detections of metals or VOCs and provide an analysis of the chemicals detected relative to permit requirements contained in the Temporary Permit and Prevention of Significant Deterioration Permit.

XVIII (K) Within 60 days after the first year of operation, AES shall provide DES with a detailed report on all water quality data collected during the initial year of operation. This report must include, as a minium, an analysis of performance relative to permit conditions, the ranges of concentrations (minimum, maximum and average) and quantities of contaminants which may have been released to the environment, and copies of all data sheets. AES may propose an alternative testing schedule based on the results from the initial year. If proposed, an alternative testing schedule shall not be implemented by AES until DES has issued a written approval.