Entergy

report

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

June 26, 2000

Files
(02-F-0342

Via Federal Express

Chris Hogan
Project Manager
New York State Department of Environmental Conservation
Division of Environmental Permits
625 Broadway, 4th Floor
Albany, NY 12233-1750

Subject: **Part 201 Air Permit Application**

Reference: **Entergy Indian Point Peaking Facility, LLC - Indian Point Peaking Facility**

Dear Mr. Hogan:

On behalf of Entergy Indian Point Peaking Facility, LLC (Entergy IPPF), enclosed please find three copies of the Indian Point Peaking Facility Part 201 Air Permit Application. The application was prepared in accordance with the Project's Air Quality Modeling Protocol which was approved by your Department pursuant to a memorandum from Robert S. Gaza dated April 26, 2002. Air quality modeling data files prepared in support of the Part 201 Air Permit Application are included on the enclosed compact disks.

Entergy IPPF is preparing an application for a Certificate of Environmental Compatibility and Public Need pursuant to Article X of the New York State Public Service Law. The enclosed documentation is being submitted at least 60 days in advance of submittal of the Article X application in accordance with clause 6(a) of the Project's draft general stipulation. A copy of the attached application has also been provided to the individuals listed on the attached Article X Service List.

The enclosed application also contains draft Title IV Acid Rain and NOx Budget Permit Applications for informational purposes. Signed, original applications will be filed under separate cover.

Entergy IPPF sincerely appreciates your time and effort in reviewing the enclosed application, and looks forward to working with the NYSDEC throughout the Article X process. If you have any questions, feel free to contact Ms. Jolecia Marigny of my staff at 832.681.3388 or Mr. Kevin Maher at TRC Environmental at 201.933.5541, ext. 108 at your earliest convenience.

Sincerely,

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Senior Vice President & COO
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Entergy Indian Point Peaking Facility, LLC – Indian Point Peaking Facility
Part 201 Air Permit Application

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TRC

Customer-Focused Solutions

NYS Department of Environmental Conservation Part 201Air Permit Application for Indian Point Peaking Facility

Prepared for:

Entergy Indian Point Peaking Facility, LLC

Prepared by:

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June 2002

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LIST OF ACRONYMS

Acronym	Definition
AGL	above grade level
AMSL	above mean sea level
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
BPIP	Building Profile Input Program (version 95086)
Btu	British thermal unit
CAAA	Clean Air Act Amendments
CEMS	continuous emissions monitoring system
CFR	code of federal regulations
CO	carbon monoxide
CO_2	carbon dioxide
DEM	Digital Elevation Model
DLN	dry low-NO_x
ERCs	emission reduction credits
F	fluoride
ft	feet
GE	General Electric
GEP	good engineering practice
H_2O	water
H_2SO_4	sulfuric acid
HAP	Hazardous Air Pollutant
HHV	higher heating value
HP	high pressure
hr(s)	hour(s)
ISCST3	Industrial Source Complex Short-term (Version 00101) model
K	Kelvin
km	kilometer
LAER	Lowest Achievable Emission Rate
lb/hr	pounds per hour
lb/mmBtu	pounds per million British thermal units
$\mu g/m^3$	microgram per cubic meter
m/s	meters per second
MACT	Maximum Achievable Control Technology
mmBtu/hr	million British thermal units per hour
MOU	Memorandum of Understanding
MSL	mean sea level
MW	megawatt
N_2	nitrogen gas
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
$(NH_4)_2SO_4$	ammonium sulfate salts
NH_4HSO_4	ammonium bisulfate

Acronym	Definition
NNSR	Non-Attainment New Source Review
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
NYAQS	New York Air Quality Standards
NYCRR	New York Code of Rules and Regulations
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
O_2	oxygen
O_3	ozone
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
Pb	lead
PM	particulate matter
PM-10	particulate matter with an aerodynamic diameter of 10 micrometers or less
ppm	parts per million
ppmvd	parts per million dry volume
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
scf	standard cubic feet
SCR	Selective Catalytic Reduction
SILs	Significant Impact Levels
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_3	sulfur trioxide
TSP	total suspended particulate
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1.0 INTRODUCTION

1.1 Project Overview

Entergy Indian Point Peaking Facility, LLC (Applicant or Entergy IPPF) is proposing to construct, own and operate a nominal 330 megawatt (MW) simple-cycle electric generating facility (Facility) to be located on an approximate 5-acre parcel of land adjacent to the existing Indian Point Nuclear Generation Station Units No. 2 and 3 located in the Village of Buchanan, Westchester County, New York. A site location map is included as Figure 1-1. While the proposed Facility will be located on land adjacent to the Indian Point Nuclear Generating Station Units No. 2 and 3, it will be separate from, and independent of, the nuclear generating stations.

The proposed Facility will be powered by two General Electric (GE) 7FA simple-cycle combustion turbines. The combustion turbines will fire natural gas exclusively and will operate in simple-cycle mode (no heat recovery). The turbines will utilize dry low-NO_x (DLN) combustors and selective catalytic reduction (SCR) to control nitrogen oxide (NO_x) emissions. An oxidation catalyst will be used to control emissions of carbon monoxide (CO) and volatile organic compounds (VOC). A natural gas preheater will raise the temperature of the natural gas fuel before firing to improve the efficiency of the combustion process. Upon leaving the emission control systems, the exhaust gases will be directed into two individual 18 foot by 31 foot rectangular stacks with a height of 94 feet above grade.

The combustion turbines will serve as peaking units and supply power primarily during periods of high power demand. Depending on demand, one or two turbines can operate at any given time. Each combustion turbine will operate between 50% and 100% of the combustion turbine capacity rating.

Construction of the proposed Facility is scheduled to begin in June of 2003 (pending receipt of all necessary approvals) and operation is scheduled to begin by June 2004.

1.2 Facility Emissions

Air emissions from the Facility are primarily products of combustion of natural gas in the combustion turbines. Pollutants regulated under federal and state programs include NO_x, CO, sulfur dioxide (SO_2), VOC, total particulate matter (PM), particulate matter having a diameter less than 10 micrometers (PM-10) and sulfuric acid mist (H_2SO_4). Proposed short-term emission limits and total potential annual emissions for the Facility are summarized in Table 1-1. As shown in Table 1-1, proposed emissions from the Facility will be below the applicable 250 tons per year Prevention of Significant Deterioration (PSD) major source emissions threshold.

1.3 Regulatory Summary

The proposed Facility is located in Westchester County, which is designated as attainment for all criteria pollutants, except for ozone, for which it is designated as "severe non-attainment." (Note: Westchester County has recently been determined to be in "attainment" for CO. However, Entergy IPPF understands that the redesignation process has not been completed as a regulatory matter. As such, Entergy IPPF is moving forward as if certain requirements related to Non-attainment New Source Review for CO are still in effect.) Simple-cycle combustion turbine facilities with the potential to emit attainment pollutants in excess of 250 tons per year (tons/yr) are subject to Prevention of Significant Deterioration (PSD) review. PSD requirements, discussed in greater detail in Section 3, include the determination and application of Best Available Control Technology (BACT) to pollutants that exceed PSD significant emission rate thresholds. Potential emissions for all attainment pollutants will be below the 250 PSD major new source threshold (See Table 1-1). Therefore, the Facility is not subject to PSD review.

Westchester County is classified as severe non-attainment for ozone. Therefore, facilities emitting more than 25 tons/yr of NO_x or VOC are subject to 6 NYCRR Part 231 Non-Attainment New Source Review (NNSR) for these pollutants. NNSR requirements, also discussed in Section 3, include meeting Lowest Achievable Emission Rate (LAER) levels and obtaining emission offsets.

Calculated potential emissions of NO_x are greater than the NNSR 25 ton/yr major source threshold. However, potential VOC emissions will be below the 25 ton per year threshold. As such, the proposed Facility will be subject to Non-Attainment New Source Review for NO_x, but not for VOC.

The following is a summary of additional major regulatory requirements that will apply to the Facility.

1.3.1 New Source Performance Standards

The Facility must meet the federal New Source Performance Standards (NSPS) codified in 40 CFR 60, Subpart GG for combustion turbines. The proposed emission rates for the turbines are more stringent than the applicable NSPS limits. Therefore, the Facility will meet the requirements for NSPS.

1.3.2 Maximum Achievable Control Technology

Any new combustion turbine source with potential emissions greater than 10 tons/yr for any one hazardous air pollutant (HAP), or 25 tons/yr for all HAPs combined, is considered a major source and therefore subject to Maximum Achievable Control Technology (MACT) requirements. Potential HAP emissions for the Facility do not exceed either of these thresholds and, as such, are not subject to MACT.

1.3.3 New York State Department of Environmental Conservation (NYSDEC) Requirements

Applicable limits and/or industrial guidelines are summarized below:

- To meet NYSDEC guidelines for ammonia (NH_3) emissions from SCR systems on simple-cycle combustion turbines, stack emissions of ammonia (NH_3) slip will be limited to 10 ppm.

- Visible emissions from stationary combustion installations are restricted under Subpart 227-1.3 to no greater than 20 percent opacity (six minute average), except for one six-minute period per hour of not more than 27 percent opacity. The Facility will fire only natural gas and will incorporate good combustion practices which will limit visible emissions from the Facility to below this limit.

- NO_x Budget program requirements are defined under Part 204 for year 2003 and beyond. These regulations include information on allowance allocations, banking, trading, and account reconciliation, NO_x monitoring and reporting, and regulatory time lines. The Applicant will procure sufficient ozone season NO_x allowances and implement a NO_x Budget management program once operational.

- 6 NYCRR 200.6 requires that Facility emissions must not cause ambient air concentrations to exceed state air quality standards. The atmospheric dispersion modeling presented in this application demonstrates that Facility impacts will not cause or contribute to exceedances of these standards.

- Pursuant to 6 NYCRR 227-2, "reasonably available control technology" (RACT) requirements are imposed on qualifying stationary sources of NO_x. The proposed use of SCR to meet NO_x LAER, in addition to low-NO_x turbine technology, will result in NO_x emissions below applicable RACT standards. Note that specific Part 227-2 requirements related to record-keeping and reporting will apply.

NYSDEC requirements not directly related to air emissions, but potentially related to the Facility in general, including 6 NYCRR Parts 202-1 (source testing), Part 202-2 (annual emission statement) and Part 207 (air pollution episode control measures), will be addressed and/or incorporated into the Part 201-6 Permit pursuant to established regulatory deadlines. The NYSDEC Part 201 permit application is located in Appendix A.

1.4 Summary of Proposed Limits

Table 1-1 summarizes the proposed emission limits for each pollutant (in ppm and/or lb/mmBtu) as well as annual emission limits. As illustrated in Table 1-1, potential emission calculations (based on unrestricted annual operation) for all attainment pollutants (CO, PM-10, SO_2 and H_2SO_4) result in totals less than the major source thresholds for PSD.

Since potential NO_x emissions exceed the NNSR threshold, NO_x is subject to Non-Attainment New Source Review requirements. Potential VOC emissions, however, are below the NNSR threshold.

1.5 Impact on Ambient Air Quality Standards

The air quality impact analysis (presented in Section 7) was performed in accordance with U.S. EPA modeling guidelines and the modeling protocol submitted to NYSDEC on March 22, 2002 and approved on April 26, 2002. (Appendix C contains all related agency correspondence.) The dispersion modeling utilizes five years of meteorological data collected by the meteorological tower at Indian Point 3 from January 1996 through December 2000. This data was supplemented with concurrent mixing height data obtained from the National Weather Service (NWS) upper air observation station in Albany, New York and surface meteorological data obtained from the NWS station at Stewart International Airport near Newburgh, New York.

The results of this modeling show that predicted Facility impacts are below PSD significant impact levels (SILs) for all pollutants. According to U.S. EPA and NYSDEC requirements, since the Facility impacts are below SILs, it will not have the potential to affect compliance with National Ambient Air Quality Standards (NAAQS), PSD increments, or New York State standards for criteria pollutants. Therefore, no additional air quality modeling is necessary for this Project.

1.6 Application Organization

Section 2 of this application provides a description of the Facility design, operating modes, emission sources and control. In Section 3, the applicable regulatory requirements are outlined. A control technology analysis based on these regulations is presented in Section 4. Sections 5 and 6 detail the requirements of Non-Attainment areas and Title IV (the sulfur dioxide allowance program), respectively. The supporting air quality modeling analyses are presented in Section 7. Finally, Appendices have been included which contain completed New York State Application Forms, emission calculations, RACT/BACT/LAER Clearinghouse search results and draft Acid Rain and NOx Budget Application forms.

Table 1-1: Proposed Facility Emissions [a]				
Pollutant	Maximum Emissions [b] (per unit)			Annual Emissions Limit [c]
	GE 7FA Gas Turbine		Natural Gas Preheater	
	ppm	lb/mmBtu	lb/mmBtu	tons/year
Nitrogen Oxides	4.0	0.0163	0.1100	230.0
Carbon Monoxide	2.7	0.0067	0.0400	94.2
Volatile Organic Compounds	1.0	0.0014	0.0250	20.5
Sulfur Dioxide	N/A	0.0014	0.0014	22.2
PM/PM-10	N/A	0.0199	0.0090	196.8
Sulfuric Acid	N/A	0.0016	0.0001	25.4
Ammonia	10	N/A	N/A	207.2

(a) All proposed emission limits (in units of ppm and lb/mmBtu) are maximums across all loads and temperatures and do not serve as the basis for determining annual emission limits from the proposed Facility. Refer to Appendix B of this application for documentation of pollutant hourly emission rates and concentrations used in the potential annual emissions calculations.

(b) "ppm" refers to ppmvd @ 15% O_2; lb/mmBtu values are HHV basis.

(c) Annual emissions include emissions from the simple-cycle units, startups/shutdowns and one fuel gas heater. Potential emissions from the combustion turbines are based on 8,760 hours per year and 100% load at an ambient temperature of 50°F. Potential emissions from the gas heater are based on 8,760 hours per year of operation.

2.0 FACILITY DESCRIPTION

2.1 Facility Conceptual Design

The proposed Indian Point Peaking Facility will consist of two General Electric (GE) 7FA combustion turbines operating in simple-cycle mode with a total nominal output of 330 MW (165 MW each). The turbines will exclusively burn natural gas. The units will be equipped with a fogging-type inlet air cooling system to further boost power and efficiency on hot days. Fuel gas preheaters will be used to raise the temperature of the natural gas prior to combustion. Each turbine will employ DLN burners and a high temperature SCR to minimize concentrations of NO_x in the exhaust stream. An oxidation catalyst will be used to control emissions of CO and VOC. The turbines and control systems, along with turbine/generator auxiliary equipment skids, will be housed in a main generator building.

The simple-cycle turbines will serve as peaking units to supply power during periods of high power demand. As such, the Facility will be dispatchable, but will be designed to operate on a continuous basis as needed. Due to the dispatchable nature of the Facility, periods of part-load operation and multiple start-ups/shutdowns per week may occur.

A plot plan showing proposed equipment locations is presented in Figure 2-1 and a conceptual flow diagram is presented in Figure 2-2.

2.1.1 Combustion Turbine Simple-Cycle Units

Entergy IPPF is proposing to install two GE 7FA combustion turbines at the Project site. The maximum heat input rate for each turbine is 1,979 million British thermal units per hour (mmBtu/hr). This value is based on the higher heating value of the fuel and an ambient temperature of -10 °F.

Each combustion turbine consists of an air compressor, combustion chamber, gas turbine, and an electric generator. Part of the power produced in the gas turbine is used to drive the compressor. The remaining power drives the electric generator. Ambient air enters the compressor inlet through a filtration system. Air is compressed by passing through a series of rotating and stationary compressor blades. The compressed air is then passed into the burner section where natural gas is fired from burners that form a ring around the circumference of the combustion turbine section casing.

The hot gas from the burners combines with the compressed air to produce a high-pressure gas stream which enters the turbine and passes through a series of stationary and rotating turbine blades. The stationary blades channel the hot gas onto the rotating stages in a manner that imparts a motive force on the axial shaft. Enough energy is produced in the turbine section to drive the compressor and to induce the generator attached to the shaft to produce a nominal net output of approximately 165 MW.

After exiting the combustion turbine, mixing with cooling air and passing through the air pollution control system, the turbine exhaust gases (consisting primarily of nitrogen, water and carbon dioxide) will be discharged to the atmosphere. Each unit will vent through a separate stack rising 94 feet above grade.

2.1.2 Fuel Gas Preheaters

Entergy IPPF is proposing to install two natural gas-fired fuel preheaters, each with a maximum heat input rate of 11.8 mmBtu/hr, based on the higher heating value (HHV) of the fuel. Only one preheater will operate at any given time, with the second preheater in place as a backup. Each 11.8 mmBtu/hr, HHV fuel gas heater will exhaust to two (2) stacks (for a total of four (4) stacks). The four (4) stacks will be contained within a single 94-foot outlet.

2.1.3 Air Pollution Control Systems

The emission control technologies proposed for the Facility include dry low-NO_x burners and SCR to control NO_x emissions. CO and VOC emissions will be minimized through the use of good combustion practices and an oxidation catalyst. SO_2 and PM/PM-10 will be minimized through the exclusive use of clean burning natural gas.

2.1.3.1 Dry Low-NO_x Burners

NO_x formation can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low-NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. The "dry" description stems from the reduction of NO_x emissions without the use of water injection.

DLN burner technology uses a two-stage combustor that remixes a portion of the air and fuel in the first stage and injects the remaining air and fuel into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required which, in turn, results in lowered NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state-of-the-art for NO_x control in combustion turbines.

2.1.3.2 Oxidation Catalyst

After combustion control, the only practical method to reduce CO and VOC emissions from the combustion turbine units is an oxidation catalyst. Exhaust gases from the turbines are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide. The oxidation catalyst for the proposed Facility will reduce CO emissions by 70% and VOC emissions by 10%.

2.1.3.3 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR), a post-combustion chemical process, will be installed to further treat exhaust gases downstream of the combustion turbine and the oxidation catalyst. An ambient air dilution system will be used to cool the turbine exhaust gas to a level where the SCR provides effective NO_x control. Aqueous ammonia will be injected into the flue gas stream, upstream of an SCR catalyst, where it will mix with the NO_x (predominantly NO and NO_2 at that point). The mixture will pass through a catalyst bed to reduce NO and NO_2 to nitrogen gas (N_2) and water.

Aqueous ammonia (19% solution) will be the reagent for the SCR. Ammonia that does not react will pass out of the stack. This unreacted ammonia is termed "ammonia slip." The SCR system will reduce NO_x concentrations to 4.0 parts per million by volume dry (ppmvd) at 15 % O_2. Ammonia slip will be limited to 10 ppm or less.

2.1.4 Ammonia Tank

Ammonia used in the SCR system will be supplied from a 15,000-gallon aqueous ammonia storage tank. The maximum aqueous ammonia concentration will be 19% by weight. This concentration is below the threshold for risk management planning applicability given under Section 112(r) of the Clean Air Act Amendments (See 40 CFR 68.130).

2.2 Fuel

Entergy IPPF is proposing to utilize natural gas as the exclusive fuel for the turbines and fuel gas preheaters. The natural gas is assumed to have a higher heating value (HHV) of approximately 1,020 Btu/standard cubic feet (SCF) and is conservatively assumed to contain 0.5 grains of sulfur per 100 SCF on an annual average basis.

2.3 Facility Operating Modes

The Facility will be dispatchable, but will be designed to operate on a continuous basis as needed. Each combustion turbine will operate between 50% to 100% of the combustion turbine load. Because the turbine emission rates and exhaust characteristics differ with varying loads and ambient temperatures, a matrix of operating modes is employed in the various analyses in this application, including the air quality impact analysis and potential emissions calculations. The range of operating conditions evaluated for the Facility is defined by the following variables: three loads (50%, 75%, and 100%) and three ambient temperatures (-10 °F, 50 °F, and 100 °F) selected as appropriate for characterizing the site in accordance with NYSDEC guidance. In addition, the units will be equipped with a fogging-type inlet air cooling system to further boost power and efficiency on hot days. These variables result in ten different operating scenarios for the Facility.

2.4 Source Emission Parameters

Emissions of air contaminants from the proposed Facility are estimated based upon vendor emission estimates, emission factors presented in the US EPA Guidance Manual AP-42, mass balance calculations and engineering estimates. Emission calculations used to develop the emission estimates presented in this application are presented in Appendix B.

2.4.1 Criteria Pollutant Emissions from the Combustion Turbines and Gas Heaters

Exhaust and emission parameters are presented for three ambient temperatures (-10, 50, and 100 °F), three turbine loads (50%, 75%, and 100%), the inlet fogger operating at 100 °F (at 100% load only) and one fuel type (natural gas) for a total of ten operating conditions. Appendix B provides more detailed emissions data together with exhaust gas characteristics.

Emission rates for VOC, NO_x, CO and PM/PM-10 from the combustion turbine are estimated based upon vendor emission estimates. Control efficiencies for SCR NO_x conversion are based upon catalyst vendor guarantees for systems designed to achieve the prescribed LAER levels. The CO and VOC reduction efficiencies of the oxidation catalyst are also based on catalyst vendor guarantees. Worst-case SO_2 emission rates have been estimated based upon worst-case mass balance of fuel sulfur loading. The PM-10 emissions include an allowance for ammonia salt formation due to the reaction of excess ammonia (NH_3) with sulfur trioxide (SO_3), assuming that 75% of the fuel sulfur is oxidized to SO_3 (taking into account the effect of the SCR and oxidation catalyst). Note that the sulfur assumed to subsequently react with NH_3 has not been subtracted from the SO_2 estimate (likewise with sulfuric acid mist) in order that all estimates may be conservative.

2.4.2 Other Pollutant Emissions from the Combustion Turbines and Gas Heaters

Potential emissions of sulfuric acid mist from the combustion turbines and fuel gas heaters are calculated assuming a conversion of 75% and 5%, respectively, of fuel sulfur to SO_3 in the combustion and emission control processes, and a subsequent reaction of all SO_3 with water to form sulfuric acid mist (H_2SO_4).

Emissions of ammonia (ammonia "slip") from the combustion turbines will be 10 ppm or less, based on vendor data, and in accordance with NYSDEC policy for SCR systems on simple-cycle combustion turbines.

Potential emissions of HAPs are based on U.S. EPA AP-42 emission factors and are presented in Appendix B.

2.4.3 Facility Potential Annual Emissions

In calculating the Facility's potential-to-emit (PTE), the annual Facility emissions are based on operating assumptions that include:

- Operation of both turbines at 100% load at an ambient temperature of 50°F;
- Operation of both turbines and one gas heater for 8,760 hours per year;
- 260 turbine start-ups and shutdowns per year per turbine. (The downtime prior to a start-up is taken into account when calculating whether the start-ups will increase the PTE for a pollutant.)

Detailed calculations are provided in Appendix B.

2.5 Process Control and Emissions Monitoring

The Facility will be equipped with a sophisticated process control system to ensure compliance with permitted emission limits. The distributed control system (DCS) will monitor critical Facility components and make automatic adjustments as necessary to ensure efficient combustion that minimizes emissions.

To ensure compliance with the emission and fuel requirements, the Facility will monitor and record fuel consumption as required by New Source Performance Standards (NSPS) per 40 CFR Part 60, Subpart GG, which also requires monitoring of fuel sulfur and nitrogen content. A custom fuel monitoring schedule/exemption request will be developed and submitted to NYSDEC and U.S. EPA for approval prior to operation.

The Facility will install a continuous emissions monitoring system (CEMS) to comply with requirements of federal programs and demonstrate compliance with state permit limits. Under the Acid Rain Program (Title IV, CAAA) and NO_x Budget Program, CEMS meeting 40 CFR Part 75 requirements will be installed to monitor NO_x mass emissions. CO_2 emissions will be monitored and reported in accordance with 40 CFR Part 75 Appendix G. The Facility is exempt from the continuous opacity monitoring requirements of Title IV as the unit will fire natural gas in the combustion turbines for at least 85 percent of the unit's average annual heat input. A CEMS will also be installed to monitor CO.

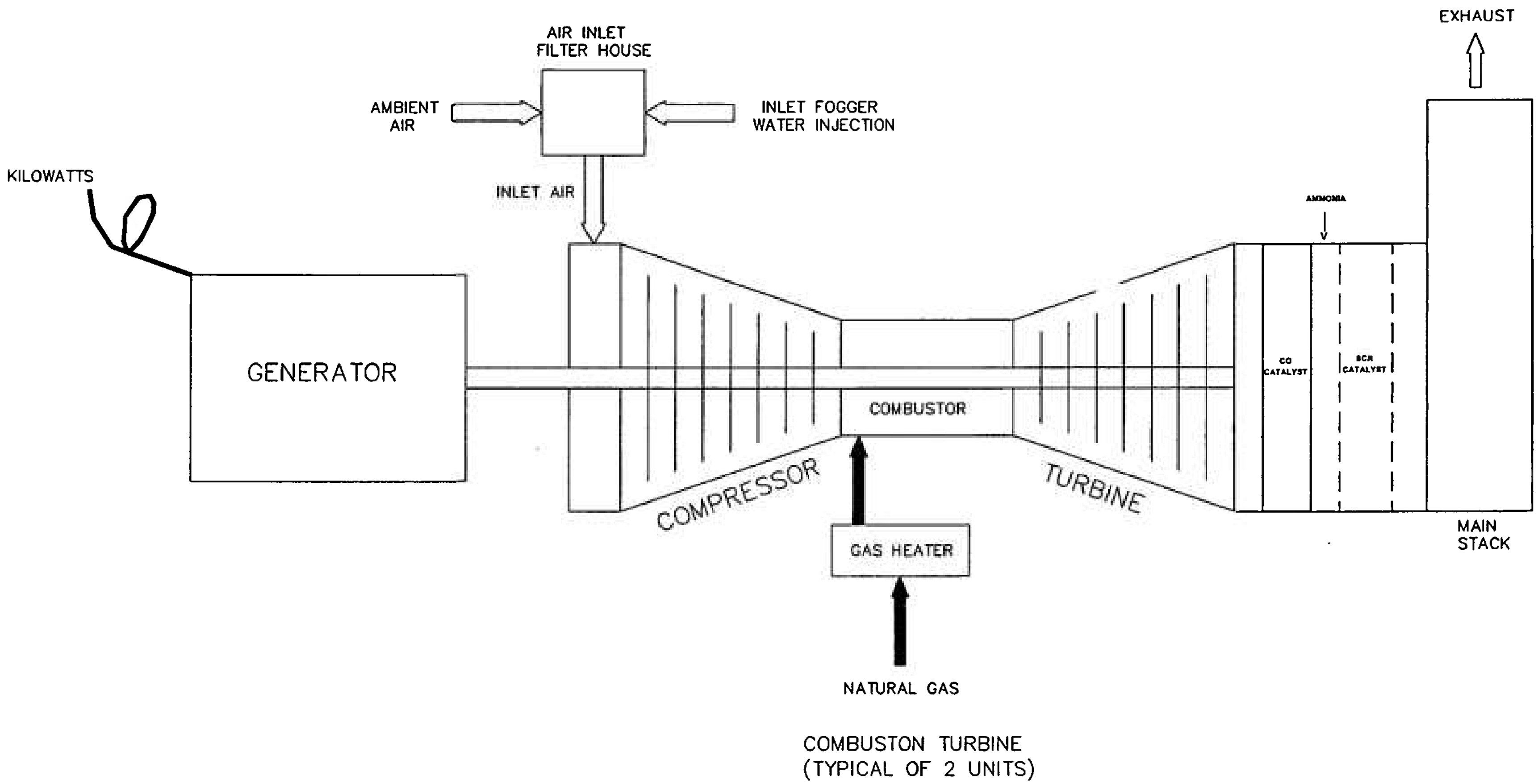

Figure 2-2.
Simple Cycle Process Diagram

INDIAN POINT
GE7FA PROJECT

STONE & WEBSTER INC.
A SHAW GROUP CO.

DRAWING NUMBER 13265.0004-SK-25

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3.0 APPLICABLE REQUIREMENTS AND REQUIRED ANALYSES

This section contains an analysis of the applicability of federal and state air quality regulations to the proposed Facility. The specific regulations included in this review are:

- National and New York State ambient air quality standards;
- Prevention of Significant Deterioration (PSD) requirements
- Non-Attainment New Source Review (NNSR) requirements;
- Federal New Source Performance Standards (NSPS);
- NO_x Budget Program requirements;
- Federal Acid Rain Program requirements; and
- NYSDEC regulations and policy.

3.1 Regional Attainment Status And Compliance With Air Quality Standards

For the protection of public health and welfare, U.S. EPA has established primary and secondary National Ambient Air Quality Standards (NAAQS) for six criteria pollutants: sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter (PM-10), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), and lead (Pb). The NYSDEC has adopted most of the NAAQS as the New York Ambient Air Quality Standards (NYAAQS), as shown in Table 3-1. In addition, NYSDEC has established NYAAQS for total suspended particulates (TSP), gaseous fluoride, beryllium, and hydrogen sulfide.

The proposed location of the Facility is in an area currently designated as attainment or unclassifiable for CO, SO_2, NO_2, and PM-10. Therefore, for these pollutants, the Facility is required to demonstrate compliance with the NYAAQS and NAAQS. (Note: Westchester County has recently been determined to be in "attainment" for CO. However, Entergy IPPF understands that the redesignation process has not been completed as a regulatory matter. As such, Entergy IPPF is moving forward as if certain requirements related to Non-attainment New Source Review for CO are still in effect.)

Westchester County is designated as severe non-attainment for ozone. Therefore, facilities emitting more than 25 tons/year of NO_x or VOC are subject to Non-Attainment New Source Review (NNSR) requirements for these pollutants. Because of the temporary continuance of certain NNSR requirements for CO, sources emitting more than 100 tons/yr of CO are subject to these requirements until they are rescinded. As a result, Entergy IPPF has decided to utilize an oxidation catalyst (which would have been required as LAER for CO) to reduce CO emissions to less than the 100 ton/yr non-attainment threshold.

In order to identify those new sources with the potential to impact ambient air quality, the U.S. EPA and the NYSDEC have adopted Significant Impact Levels (SILs) for NO_2, SO_2, CO, and PM-10, also shown in Table 3-1. New sources that have maximum modeled air quality impacts that exceed SILs require a more comprehensive analysis that considers the combined impacts of the new source, existing sources, and measured background levels, in order to evaluate compliance with NAAQS and compliance with PSD increments. According to the NYSDEC and the U.S. EPA, sources with impacts below the SILs do not warrant such an assessment. Predicted air quality impacts for the proposed Facility that are below SILs, as demonstrated in Section 7.

3.2 Prevention of Significant Deterioration (PSD) Requirements

As mentioned in the previous section, the proposed Facility will be located in an area currently designated as attainment for CO, SO_2, NO_2, and PM-10. As described in Section 1 of this application, the proposed Facility is a separate source from Indian Point Nuclear Generating Stations Units No. 2 and 3. New major sources would require permitting under the PSD program, including a BACT analysis and a NAAQS compliance demonstration. Under PSD, the term "major source" is defined as any source belonging to a list of 28 source type categories which emits or has the potential to emit 100 tons/yr or more of any regulated pollutant, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons/yr. Under the PSD program, a combustion turbine simple-cycle generation facility does not fall within one of the 28 listed source categories and as such would be subject to the 250 ton/yr PSD major source threshold.

Table 3-2 summarizes the proposed annual emission rates for the Facility. Since all proposed emissions of attainment pollutants will be below 250 tons/yr, the Facility is not subject to PSD review.

3.3 Non-Attainment New Source Review (NNSR) Requirements

As previously stated, Westchester County is currently designated as severe non-attainment for ozone. As such, new sources emitting precursors of ozone (NO_x, and VOC) in excess of the NNSR threshold listed in Table 3-2 are subject to non-attainment new source review (NNSR) as outlined in 6 NYCRR 231-2. Requirements of NNSR include the purchase of emissions offsets (equal to 1.3 times permitted annual emissions in a severe ozone non-attainment area), as well as determination and application of control technology resulting in the lowest achievable emission rate (LAER). LAER is defined as the most stringent emission limitation achieved in practice, or which can reasonably be expected to occur in practice, by the class or category of source. Additional requirements of NNSR include an analysis of alternative sites, sizes and technologies, as well as certification of compliance for all other major Entergy facilities in New York State.

As shown in Table 3-2, the Facility is considered a "major source" under NNSR criteria since it has emissions greater than 25 tons/yr for NO_x and therefore must maintain LAER levels for this pollutant. Potential emissions of VOC will be below the major source threshold and, as such, will not be subject to NNSR.

As stated above, certain NNSR requirements apply to major CO sources locating in Westchester County. As shown in Table 3-2, the proposed Facility is not a major source for CO and is not subject to NNSR provisions for that pollutant.

3.4 Maximum Achievable Control Technology (MACT)

On April 20, 2000, an interpretive rule was published in the Federal Register (Volume 65, Number 78, page 21363-21365, April 20, 2000) stating that new combustion turbines are subject to case-by-case MACT if they are a major source of hazardous air pollutants (pursuant to 40 CFR 63). Any new source with potential emissions greater than 10 tons per year (tons/yr) for any one hazardous air pollutant (HAP), or 25 tons/yr for all HAPs combined, is considered a major source. As demonstrated in Appendix B, HAP emissions for the Facility will not exceed either of these MACT thresholds.

3.5 Federal New Source Performance Standards (NSPS)

The NSPS are technology-based standards applicable to new and modified stationary sources. The NSPS requirements have been established for approximately 70 source categories. Standards of Performance for Stationary Gas Turbines (40 CFR Part 60, Subpart GG) and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units apply to the Facility; all NSPS units are also subject to the General Provisions (40 CFR Part 60, Subpart A).

3.5.1 40 CFR Part 60 Subpart A: General Provisions

Subpart A details the general requirements for stationary sources that are subject to NSPS requirements, including notification and record keeping, performance tests and monitoring. The Facility is subject to NSPS requirements and will therefore comply with the Subpart A requirements.

3.5.2 40 CFR Part 60 Subpart GG: Stationary Combustion Turbines

The combustion turbines are subject to the provisions of 40 CFR Part 60 Subpart GG due to the maximum firing capacity of the turbines and the date of installation. The emission standards (40 CFR Part 60.332 and 60.333) for flue gas concentrations of NO_x are no more stringent than 75 ppm (based on the turbine heat rate and the fuel bound nitrogen) and SO_2 to 150 ppm (or 0.8% sulfur in fuel). The Facility's combustion turbine emissions are well below these levels. Additionally, the provisions of this subpart require the installation of a continuous emission monitoring system (CEMS) for fuel consumption and water-to-fuel ratio. Subpart GG also requires monitoring of fuel sulfur and nitrogen content and allows for the development of a custom schedule to monitor these parameters.

3.5.3 40 CFR Part 60 Subpart Dc: Steam Generating Units

This regulation applies to units with a maximum design heat input capacity of 100 mmBtu/hr or less, but greater than 10 mmBtu/hr. The Project's fuel gas heaters boiler will be rated at 11.8 mmBtu/hr (natural gas only). Because the heaters will only burn natural gas, the only applicable requirements include the recordkeeping and reporting requirements outlined in Part 6.48c.

3.6 NO_x Budget Program Requirements

On September 27, 1994 the Ozone Transport Commission (OTC) adopted a Memorandum of Understanding (MOU) committing the signatory states to develop and propose region-wide NO_x emission reductions in 1999 (Phase 2) and 2003 (Phase 3). The NO_x Budget Model Rule implements the OTC MOU NO_x emission reduction requirement through a market-based "cap and trade" program. This type of program sets a regulatory limit on emissions in non-attainment areas during the "ozone season" (May 1 through September 30); allocates allowances authorizing emissions up to the regulatory limit; and permits trading of allowances in order to bring about cost-efficient compliance with the cap on the non-attainment area emissions. The number of allowances allocated is limited by the cap on non-attainment area emissions. A NO_x allowance authorizes one ton of emissions of NO_x during the ozone season. At the end of the ozone season affected sources must hold allowances greater than or equal to actual NO_x emissions during the ozone season. Sources are allowed to buy, sell, or trade allowances to meet their needs.

Regulations covering New York State's implementation of the Phase 3 Program were finalized late in 1999 and have been codified in 6 NYCRR Part 204. Allowances for an affected unit will be based on actual operations during specific, preceding baseline periods, and will be "self-adjusting" based on the affected unit's operating history. NO_x allowances will be set aside for new sources and to reward energy efficiency measures. The allowances that have been set aside will be provided to new sources to cover actual NO_x emissions; new sources will continue to receive allowances until they establish a 3-year baseline of operations. At that point, a new facility will be entered into the Phase 3 budget pool and will have allowances allocated to it following the formula applied to all other existing sources.

In order to ensure that NO_x emissions do not exceed allowances, sources are required to monitor and report NO_x emissions. The preferred method of emissions monitoring includes utilization of a sophisticated continuous emissions monitoring system (CEMS), as approved under 40 CFR 75 (the Acid Rain Program).

A copy of the Facility's draft NO_x Budget Permit Application is included in Appendix E. A final application will be filed with the appropriate agencies at a later date.

3.7 Federal Acid Rain Regulations

Title IV of the CAAA required U.S. EPA to establish a program to reduce emissions of acid rain forming pollutants, called the Acid Rain Program. The overall goal of the Acid Rain Program is to achieve significant environmental benefits through reductions in SO_2 and NO_x emissions. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution. Under the program, existing units are allocated SO_2 allowances by the U.S. EPA. Once allowances are allocated, affected facilities may use their allowances to offset emissions or trade their allowances to other units under a market allowance program. In addition, applicable facilities are required to install a CEMS for affected units. Because the combustion turbines are utility units that serve a generator greater than 25 MW, the Facility is subject to the Acid Rain Program requirements.

The Acid Rain Program requires CEMS for SO_2, NO_x, CO_2, a volumetric flow monitor, an opacity monitor, a diluent gas (CO_2 or O_2) monitor, and a computer based data acquisition and handling system for recording and performing calculations. Since the Facility is not a coal-fired unit it is not subject to the Acid Rain Program NO_x emission limits, although NO_x (and CO_2) needs to be continuously monitored to satisfy agency data gathering requirements. CO_2 emissions must be measured in accordance with 40 CFR 75 Appendix G. The Acid Rain Program allows for alternate methods of SO_2 monitoring for gas fired facilities such as the Facility. An allowable alternate method would include fuel flow monitoring and mass balance reconciliation of SO_2 emissions from fuel sulfur content in accordance with 40 CFR 75 Appendix D.

The Facility must submit an acid rain permit application for the combustion turbine units 24 months prior to the date on which the unit expects to begin service as a generator. A copy of the Facility's draft Acid Rain Permit Application is included in Appendix E. The final Acid Rain Permit Application will be filed with the appropriate agencies at a later date.

3.8 New York State Department of Environmental Conservation Regulations and Policies

Applicable NYSDEC Air Regulations are identified below:

- Part 200 defines general terms and conditions, requires sources to restrict emissions, allows NYSDEC to enforce NSPS, PSD, and National Emission Standards for Hazardous Air Pollutants (NESHAP). Part 200 is a general applicable requirement. It requires no action of the Facility.

- Part 201 requires existing and new sources to evaluate minor or major source status and evaluate and certify compliance with all applicable requirements. The Facility will be a major Title V source, since potential NO_x emissions exceed 25 tons/year and potential PM emissions exceed the 100 tons/year Title V major source threshold. The NYSDEC application is included as Appendix A.

- Subpart 202-1 requires a source to conduct emissions testing upon the request of NYSDEC.

- Subpart 202-2 requires sources to submit annual emission statements for NO_x and VOC for emissions tracking and fee assessment. Emissions are required to be reported in an emissions statement if certain annual thresholds are exceeded.

- Part 204 regulates the NO_x Budget program beginning with the 2003 ozone season (May through September). Program requirements, including allowance allocations, new source set-asides, banking, trading, and account reconciliation, NO_x monitoring and reporting, and regulatory time lines are addressed in Part 204. NO_x Budget program requirements are specifically addressed in Section 3.6 above.

- Part 211.3 defines general opacity limits. Facility-wide visible emissions are limited to 20 percent opacity (six-minute average) except for one continuous six-minute period per hour of not more than 57 percent opacity. Note that the opacity requirements under Part 227-1 (see below) are more restrictive and supersede the requirements of Part 211.3.

- Subpart 227-1.3 sets opacity limits for stationary combustion sources of less than or equal to 20 percent opacity (six-minute average), except for one six-minute period per hour of not more than 27 percent opacity.

- Subpart 227-2 requires that "reasonably available control technology" (RACT) be imposed on qualifying stationary sources of NO_x. The proposed use of SCR for NO_x control, in addition to low-NO_x turbine technology, will result in NO_x emissions below applicable RACT standards. Note that specific Part 227-2 requirements related to record-keeping and reporting will also apply.

- Part 231 requires new source review of new major sources. Under Subpart 232-2, which regulates sources that were operational after November 14, 1992, the Facility will need to address LAER for NO_x since potential annual emissions are greater than the 25 ton/yr significant increase threshold. Non-attainment emission offsets will be required for NO_x emissions on a 1.3 to 1 ratio basis (Section 5 addresses the required offsets).

3.9 Summary of Potential Compliance Provisions

The following monitoring, record keeping and reporting measures are proposed to demonstrate compliance with applicable state and federal regulations. They are based, in part, on recent NYSDEC permits issued for similar facilities.

1. Compliance provisions associated with the applicable regulatory requirements are addressed:

   - NSPS Subpart A (general provisions, including notification and reporting requirements);
   - NSPS Subpart GG (emission limits, stack testing, fuel monitoring and reporting for gas turbines);
   - NSPS Subpart Dc (reporting and recordkeeping requirements);
   - Title IV Acid Rain Program (continuous SO_2 emissions monitoring and reporting, and SO_2 emission allowances); and
   - NO_x Emissions Budget Program (NO_x emissions allowances during the ozone season and NO_x continuous emission monitoring).

2. Stack emission limits for all pollutants subject to permit limits at part-load and full load operations.

3. Continuous emissions monitoring of each turbine exhaust gas for:

   - Carbon monoxide;
   - Carbon dioxide;
   - Nitrogen oxides; and
   - Oxygen.

4. Parameter monitoring (or surrogate) for:

   - Fuel sulfur content;
   - Ammonia slip; and
   - SCR operating data.

5. Exhaust flow rate and SO_2, NO_x and CO_2 mass emission rate will be calculated based on alternative methods (instead of continuous emissions monitoring) in accordance with 40 CFR Part 75. Emissions will be calculated based on heat input, and a default SO_2 emission factor for gas-firing.

6. Exhaust testing:

   - Initial testing to verify exhaust parameters and emission rates of all emitted criteria pollutants from the simple-cycle units.

7. Definitions:

   - Start-up: commences with the introduction of fuel and continues until the turbines reaches 50 percent load. Start-up periods shall follow the start-up procedures as set by the manufacturer or developed by the permittee.

   - Shutdown: commences with the reduction in turbine load to less than 50 percent with the intent to stop operation. The shutdown period shall follow the shutdown procedures as set by the manufacturer or developed by the permittee.

Table 3-1: National and New York Ambient Air Quality Standards, PSD Increments and Significant Impact Levels (µg/m³)

Pollutant	Averaging Period	NAAQS	NYAAQS	PSD Increments Class II	Significant Impact Level
Sulfur Dioxide (SO_2)	3-Hour	1,300[a]	1,300[a]	512[a]	25
	24-Hour	365[a]	365[1]	91[a]	5
	Annual	80[b]	80[b]	20[b]	1
Nitrogen Dioxide (NO_2)	Annual	100[b]	100[b]	25[b]	1
Particulate (PM-10)	24-Hour	150[c]	150[c]	30[a]	5
	Annual	50[d]	50[d]	17[a]	1
Total Suspended Particulate (TSP)	24-Hour	N/A	250[e]	N/A	N/A
	Annual	N/A	45[f]	N/A	N/A
Carbon Monoxide (CO)	1-Hour	40,000[a]	40,000[a]	N/A	2,000
	8-Hour	10,000[a]	10,000[a]	N/A	500
Ozone (O_3)	1-Hour	235[e]	160[a]	N/A	N/A
Lead (Pb)[g]	Quarterly	1.5[b]	N/A	N/A	N/A
Gaseous Fluorides (as F)[g]	12-Hour	N/A	3.70[b]	N/A	N/A
	24-Hour	N/A	2.85[b]	N/A	N/A
	1-Week	N/A	1.65[b]	N/A	N/A
	1-Month	N/A	0.80[b]	N/A	N/A
Beryllium[g]	1-Month	N/A	0.01[b]	N/A	N/A
Hydrogen Sulfide[g]	1-Hour	N/A	14[b]	N/A	N/A

[a] Not to be exceeded more than once per year
[b] Not to be exceeded
[c] Fourth highest concentration over a three year period
[d] Average of three annual average concentrations
[e] Not to be exceeded more than once per year on average
[f] Geometric mean of the 24-hour average concentrations over 12-month period
[g] Pollutant will not be emitted from the Facility

Source: 40 CFR 50; 6 NYCRR 257; 40 CFR 52; and U.S. EPA, 1990[1]

[1] U.S. EPA (1990). "New Source Review Workshop Manual - Draft", Office of Air Quality Planning and Standards, Research Triangle Park, NC.

Table 3-2: Significant Emission Thresholds and Facility Potential Emission Rates

Pollutant[a]	Proposed Facility Emissions (tons/yr)	Major Source Thresholds	
		PSD (tons/yr)	NNSR (tons/yr)
Carbon Monoxide	94.2	250	100[b]
Sulfur Dioxide	22.2	250	N/A
PM-10	196.8	250	N/A
Nitrogen Oxides	230.0	250	25
VOC	205	250	25
Sulfuric Acid Mist	25.4	250	N/A

(a) Regulated substances not emitted by the Facility are not included in the table.
(b) Although the area was recently redesignated as in attainment, certain NNSR provisions still apply to major sources.

Source: TRC, 2002; 6 NYCRR 231-2, 40 CFR 52.21 (b) (23) (i) and 40 CFR 63

4.0 CONTROL TECHNOLOGY ANALYSIS FOR THE PROPOSED FACILITY

4.1 Overview

Pre-construction review for new major stationary sources involves an evaluation of Best Available Control Technology (BACT) and/or lowest achievable emission rate (LAER). If an area is attainment or unclassified for a particular pollutant, then new major sources would require permitting under the PSD program, including a BACT demonstration for emissions greater than the regulatory thresholds. However, if an area is designated as non-attainment for a given pollutant and the source has the potential to emit the non-attainment pollutant at levels greater than the pollutant-specific regulatory thresholds, then non-attainment new source review (NNSR) applies. NNSR requires the application of LAER technology and the requirement to obtain emission offsets.

Note that throughout this section, "ppm" concentration levels for gaseous pollutants are parts per million by volume, dry basis, corrected to 15% O_2 content (ppmvd @ 15% O_2), unless otherwise noted. Likewise, all emission factors expressed as pounds of pollutant per million Btu of fuel (lb/mmBtu) are based upon the higher heating value (HHV) of the fuel.

4.2 Applicability of Control Technology Requirements

An applicability determination, as discussed in this section, is the process of determining the level of emission control required for each applicable air pollutant. Control technology requirements are generally based upon the potential emissions from the new or modified source and the attainment status of the area in which the source is to be located. A detailed determination of applicable regulations, including control technology requirements under the PSD and non-attainment rules, is provided in Section 3. The following sections discuss the applicability of BACT, LAER and NYSDEC requirements for emissions from equipment included in this permit application.

4.2.1 PSD Pollutants Subject To BACT

BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental and economic impacts. Pollutants subject to PSD review are subject to a BACT analysis. The proposed Facility is not required to perform any BACT analyses since potential emissions of all attainment pollutants are below the PSD major new source threshold.

4.2.2 Non-Attainment Pollutants Subject To LAER

Pollutants subject to non-attainment NSR must be limited to LAER levels. LAER is defined as the most stringent emission limitation which is achieved in practice, or which reasonably can be expected to occur, by the class or category of source. Furthermore, NYSDEC LAER policy is that issuance of two final permits for a source category at a given emission limit level is sufficient basis for establishing LAER, regardless of whether the permitted units have been constructed. Pollutants are subject to LAER if their potential emissions exceed non-attainment area-specific emission thresholds. For the proposed Facility, emissions of NO_x are subject to LAER requirements since they exceed the severe ozone non-attainment threshold of 25 tons/yr. Potential emissions of VOC will be below the major source threshold (25 tons/yr) and, therefore, will not be subject to LAER. (Since potential emissions of CO will be less than 100 tons/yr, these emissions will also not be subject to LAER.)

4.2.3 Emission Units Subject to LAER Analysis

For a facility subject to a LAER analysis, each regulated pollutant emitted in a significant amount is subject to the prescribed level of control technology review for each emission unit from which the pollutant is emitted. Thus, the LAER analysis for NO_x applies to the simple-cycle units and the fuel gas heaters.

4.3 LAER Analysis for Nitrogen Oxides

The formation of NO_x is determined by the interaction of chemical and physical processes occurring within the combustion chamber. There are two principal forms of NO_x designated as "thermal" NO_x and "fuel" NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. The major factors influencing thermal NO_x formation are temperature, concentrations of nitrogen and oxygen in the inlet air and residence time within the combustion zone. Fuel NO_x is formed by the oxidation of fuel-bound nitrogen. NO_x formation can be controlled by adjusting the combustion process and/or installing post-combustion controls.

This section presents a LAER determination for NO_x by reviewing add-on controls for NO_x emissions and existing permit limits. As discussed in Section 4.2.2, a LAER determination for a source category is based upon the most stringent emission limitation achieved in practice, or which can reasonably be expected to occur in practice, by such class or category of source unless demonstrated to not be achievable. Furthermore, NYSDEC LAER policy is that the issuance of two permits for a source category at a given emission limit is sufficient basis for establishing LAER, regardless of whether the permitted units have demonstrated through operation that they can achieve the limit. To determine the most stringent permit limits, a search of the RACT/BACT/LAER Clearinghouse (RBLC) was performed. The results of the RBLC search for the simple-cycle turbines and the fuel gas preheaters are detailed in Section 4.3.1.

In order to reduce NO_x emissions to LAER levels, the Facility is proposing to utilize DLN combustors and SCR for the simple-cycle units and good combustion techniques for the fuel gas preheaters. Section 4.3.2 provides a technical description of NO_x control techniques for the simple-cycle units and the relative availability and suitability for the proposed Facility.

4.3.1 Review of NO_x RBLC Database

Simple-Cycle Combustion Turbines

This section evaluates NO_x emission levels reported to be "demonstrated in practice" at gas turbine simple-cycle generating facilities. This evaluation has focused on the lowest reported NO_x emission levels from facilities that produce at least 100 MW by means of natural gas-fired simple-cycle turbines. The results of the RBLC search are presented in Appendix D. In addition to those facilities identified in the RBLC database, further investigation was performed to supplement and update this list.

Since the RBLC does not always distinguish between simple- and combined-cycle units, some judgment was exercised in attempting to eliminate combined-cycle permits from consideration. (For example, any listing with reference to HRSG, duct burner, cogeneration, etc., was eliminated.)

The results of the RBLC search show that NO_x LAER for simple-cycle units can be achieved without SCR control. Further investigation was performed to supplement and update the RBLC database. Three facilities have been identified as using SCR control with lower permitted emission rates than the proposed turbines at the Facility. These facilities include the New York Power Authority (NYPA) Hell Gate Facility and other NYPA simple-cycle New York City plants (2.5 ppm NO_x), Glenwood Landing Energy Center in New York (2.5 ppm NO_x) and Port Jefferson Energy Center in New York (2.5 ppm NO_x). All these facilities consisted of LM6000 turbines with a nominal rating of approximately 42 MW. These simple-cycle aeroderivative turbines are much smaller and operate at a significantly lower exhaust temperature than the proposed GE 7FA turbines (approximately 165 MW each) and, therefore, represent a different class of engine.

Entergy IPPF is proposing to install SCR to reduce NO_x emissions to 4.0 ppm, which is the lower than the lowest emission rate currently demonstrated and/or permitted for comparable simple-cycle combustion turbines. The technical issues, including the need for an innovative ambient air flue gas cooling scheme, associated with SCR feasibility for the simple-cycle GE 7FA unit are addressed in Section 4.3.2.

Fuel Gas Preheaters

The RBLC database summary presented in Appendix D lists NO_x emission rates for external combustion units (<50 mmBtu/hr maximum rated heat input capacity). The RBLC listings are limited in this category, as many such units would not be subject to permitting or RACT/BACT/LAER requirements. The summary shows units using proper combustion techniques and natural gas firing to achieve emission levels in the range of the anticipated NO_x emission rate of 0.11 lb/mmBtu. The few sources having lower permitted NO_x emission rates than the proposed heaters for the Facility are neither the same type of source (indirect heat transfer) nor used for combustion turbine fuel pre-heating. A review of the RBLC database search shows that for small combustion units similar to the proposed fuel gas heaters, it is not common practice for these units to be equipped with add-on NO_x control technology. Furthermore, potential annual NO_x emissions from the heaters are low and will make add-on NO_x control technologies impractical.

4.3.2 Identification of NO_x Control Options and Technical Feasibility

Simple-Cycle Combustion Turbines

The following control technologies for NO_x were evaluated: lean burn combustion and selective catalytic reduction.

Lean Burn Combustion – Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel to air in the combustion zone. This is the point where the highest combustion temperature and quickest combustion reactions (including NO_x formation) occur. Fuel-to-air ratios below stoichiometric are referred to as fuel-lean mixtures (i.e., excess air in the combustion chamber); fuel-to-air ratios above stoichiometric are referred to as fuel-rich (i.e., excess fuel in the combustion chamber). The rate of NO_x production falls off dramatically as the flame temperature decreases. Very lean, dry combustors can be used to control emissions.

Based upon this concept, lean combustors are designed to operate below the stoichiometric ratio thereby reducing thermal NO_x formation within the combustion chamber. The lean combustors typically are two staged premixed combustors designed for use with natural gas fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage. The General Electric Model 7FA turbine is guaranteed to produce uncontrolled NO_x emissions of 9 ppm in the dry low-NO_x mode when firing natural gas – the lowest NO_x level commercially available from a combustion turbine.

Selective Catalytic Reduction (SCR) – SCR is an add-on NO_x control device that is placed in the exhaust stream following the gas turbine. SCR involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x contained within the air to form nitrogen gas (N_2) and water (H_2O) in accordance with 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 either a noble metal (platinum), 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. Zeolite catalysts are typically a homogenous material that forms both the active surface and the 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 gas turbine. The most common configuration is a "honeycomb" design. In an aqueous NH_3 injection system, NH_3 is drawn from a storage tank, vaporized and injected upstream of the catalyst bed. Excess NH_3 which is not reacted in the catalyst bed and which is emitted from the stack is referred to as NH_3 slip.

An important factor that affects the performance of an SCR is operating temperature. The temperature range for a standard base metal catalyst is between 400 and 800°F. Catalysts used for combined-cycle SCR are not effective in controlling NO_x at the higher temperatures associated with the uncooled exhaust of simple-cycle gas turbines. A new zeolite based catalyst which can reduce NO_x emissions from sources operating at temperatures outside the range of conventional catalytic processes has been developed. This zeolitic catalyst extends the maximum operating temperature for the reduction of NO_x using NH_3 up to approximately 1,000 ^{o}F. Since exhaust temperatures from the GE 7FA turbine are as high as 1,200 ^{o}F, an atemperation air (ambient air delivered by forced draft fans) must be added to the turbine exhaust gas to make this technology feasible for these simple-cycle turbines. While the atemperation system and catalyst have been demonstrated to be effective on smaller aeroderivative turbines, it is an innovative technology for larger turbines such as the GE 7FA proposed for this project.

A side-effect of SCR is the potential formation of ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$), which are corrosive and can stick to the duct work or stack at low temperatures and result in additional PM/PM-10 formation if emitted. NH_4HSO_4 and $(NH_4)_2SO_4$ are reaction products of SO_3 and NH_3.

Fuel Gas Preheaters

The fuel gas heater is an external combustion indirect heat exchanger that is comparable in design to a small boiler. The two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. Other technologies include staged combustion, gas reburning and add-on controls.

Flue Gas Recirculation – In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low-NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low-NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low-NO_x Burners – Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Staged Combustion and Gas Reburning – In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire air in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

SNCR and SCR – Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). SNCR is an add-on control technology that involves ammonia (NH_3) or urea injection without the use of a catalyst. SNCR involves the reaction of NO_x with ammonia, by which NO_x is converted to molecular nitrogen. Without the presence of a catalyst, flue gas temperatures must be tightly controlled between 1,600 and 1,800 ^{o}F. Temperatures below 1,600 ^{o}F will result in an increase in ammonia emissions (ammonia will not react efficiently) and temperatures above 1,800 ^{o}F will result in an increase of NO_x emissions (ammonia will react with oxygen to form NO). For SNCR to be feasible it is necessary for the flue gas to be at least 1,600 ^{o}F. This is a large heating requirement and the additional heaters required for the flue gas heating would actually offset some of the NO_x emission reductions achieved by SNCR control, since gas and/or oil heaters are sources of NO_x, plus additional CO, VOC, SO_2 and PM/PM_{10}. In the Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers. Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers. In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. SNCR has been applied successfully on larger utility-scale boilers that are field-erected, making it more practical to create a section of the boiler where ammonia or urea could be injected and mixed at the appropriate temperature with enough residence time for efficient reaction with NO_x created in the furnace. This is in contrast to the proposed equipment for the Facility which is much smaller in size.

The SCR system involves injecting ammonia (NH_3) into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data are currently available on SCR performance on natural gas fired boilers. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent. Although SCR technology has achieved a NO_x emission rate comparable to those considered LAER at other facilities, it is not considered suitable for this Facility as the boilers at facilities identified are utility boilers that are used to supply all the steam required by the facilities for heating, cooling and process needs. This is in contrast to the proposed equipment for the Facility; the gas pre-heaters have a far lower heat input rate.

4.3.3 Determination of LAER for NO_x

Simple-Cycle Combustion Turbines

The Facility proposes to use SCR technology in combination with DLN to meet a NO_x level of 4.0 ppm on a 3-hour average basis (Table 4-1). The 4.0 ppm emission rate (3-hour average) proposed for the Facility is less than any emission rate permitted for a simple-cycle turbine of this size, and further analysis is not required.

Fuel Gas Preheaters

Based on the analysis presented above, the Applicant is proposing to use proper combustion techniques and natural gas fuel to achieve a LAER of 0.11 lb/mmBtu for NO_x emissions.

4.4 Ammonia Slip Emissions

Ammonia (NH_3) emissions from the proposed combustion turbine result from the use of SCR for NO_x control. SCR involves the injection of NH_3 into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x contained within the air to form N_2 gas and H_2O as previously described.

In a typical NH_3 injection system, NH_3 is drawn from a storage tank, vaporized and injected upstream of the catalyst bed. Excess NH_3 which is not reacted in the catalyst bed, and which is emitted, is referred to as NH_3 slip.

The Facility has assumed a maximum NH_3 slip from the SCR of 10 ppm. This proposed emission limit is equivalent to limits for recently-issued permits for simple-cycle facilities utilizing cooling air with SCR. These permits include KeySpan Port Jefferson, KeySpan Glenwood, NYPA Hellgate, and other NYPA simple-cycle New York City plants.

4.5 Summary of Control Technology Proposals

Table 4–1 provides a summary of the control technology proposals presented for regulated pollutants.

Table 4-1: Summary of Proposed Control Technology and LAER Emission Limits				
Equipment	**Section**	**NO_x Emission Limit**	**Method**	**Basis**
Simple-cycle Turbines	4.3	4.0 ppm (3-hour average)	DLN Combustors & SCR	LAER
Fuel Gas Preheaters	4.3	0.11 lb/mmBtu	Nat. Gas & Good Combustion	LAER

Notes: All ppm values are parts per million by volume, dry basis, corrected to 15% oxygen.
All lb/mmBtu values are based upon the higher heating value (HHV) of the fuel.

Source: TRC Environmental, 2002

5.0 NON-ATTAINMENT AREA REQUIREMENTS

5.1 Overview

Based upon the provisions of 6 NYCRR Subdivision 231-2.4: "Permit Requirements," facilities subject to the provisions of 6 NYCRR Subpart 231-2 (i.e., major sources or major modifications located in non-attainment or transport areas) must demonstrate, as part of the permit application, that several special conditions are met. These include the need to apply LAER and obtain offsets. Offset requirements are discussed in Section 5.3. Additional requirements specific to offsetting are provided in 6 NYCRR Subdivision 231-2.4, as are other requirements related to NSR. These include:

1. The identification of each emission source from which an emission offset will be obtained. Information required must include the name and location of the facility, emission point identification number, and the mechanism(s) proposed to effect the emission reduction credit (i.e., shutdown, curtailment, installation of emission control equipment) (from 6 NYCRR Subdivision 231-2.4(a)(1)).

2. The certification that all emission sources which are part of any major facility located in New York State and under the applicant's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common ownership or control of any entity which controls, is controlled by, or has common control with the applicant) are in compliance, or are on a schedule for compliance, with all applicable emission limitations and standards under Chapter III of Title 6 (Environmental Conservation) (from 6 NYCRR Subdivision 231-2.4(a)(2)(i)).

3. The submission of an analysis of alternative sites, sizes and production processes, and environmental control techniques which demonstrate that benefits of the proposed source project or proposed major facility significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification within New York State (from 6 NYCRR Subdivision 231-2.4(a)(2)(ii)).

5.2 Compliance Status of Entergy New York Facilities

Entergy IPPF does not directly own, operate nor is affiliated with any major stationary sources as defined in 40 CFR 52.21(b)(1)(i) within New York State. Therefore, no compliance certification is required.

5.3 Emissions Offset Requirements

A major source planned in a non-attainment area must obtain emissions reductions as a condition for approval. The emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source, must (1) offset the emissions increase from the new source, (2) provide a net air quality benefit on balance (for CO and PM-10 offsets only), and (3) satisfy a "contribution test" for VOC and NO_x offsets. These offsets, obtained from existing sources which have implemented a permanent, enforceable, quantifiable and surplus emissions reduction, must equal the emissions increase from the new source or modification multiplied by an offset ratio.

The Facility is located in a severe ozone non-attainment area and will be required to purchase emission reduction credits (ERCs) from a source (or sources) that is also in a severe ozone non-attainment area. The U.S. EPA allows ERCs to be traded across state lines and the State of New York has reciprocal trading agreements with Pennsylvania and Connecticut. Various efforts have been made by NYSDEC to streamline the procedures for satisfying the "contribution test" for NO_x and VOC offsets. NYSDEC formulated one such technique which considered regional wind patterns, pollutant transport times and ozone formation mechanisms. This effort led to the development of a graphic which delineates the upwind, downwind and crosswind zones where sources of VOC and NO_x offsets can be located relative to the source needing the offsets. This graphic is presented as "Figure 2" in NYSDEC's Air Guide 26.

The calculation of required offsets for the proposed Facility is presented in Table 5-1.

5.3.1 Availability and Certification of Emission Reduction Credits

As was previously noted, each emission source providing offsets will need to be identified along with the proposed mechanism to affect the emission reduction credit. Also, NYSDEC has indicated that emission offsets need to be identified at least 60 days prior to the issuance of the final NYSDEC air permit and Article X certificate. After the sources of the emission offsets are identified, the offsets will need to be certified pursuant to the requirements of 6 NYCRR Subpart 231-2.6 "Emission Reduction Credits."

NYSDEC maintains a registry of emission reduction credits for sources that have fulfilled the requirements for certifying emission reduction credits through enforceable permit modifications. This registry may be utilized by the Facility in obtaining the required offsets.

5.4 Analysis of Alternatives

Alternative Facility siting will also be addressed in the Facility's Article X Application in accordance with 16 NYCRR Part 1001.2(d)(2). The following section details how the considerable benefits of the proposed Facility outweigh the minimal environmental impacts.

5.4.1 Facility Background

The proposed Facility will consist of two General Electric (GE) 7FA combustion turbines in simple-cycle mode and two fuel gas heaters. The combustion turbines will utilize a dry low-NO_x combustor and selective catalytic reduction (SCR) to control nitrogen oxide emissions. An oxidation catalyst will be used to control CO and VOC emissions. Upon leaving the control systems, turbine exhaust gases will be directed to two rectangular 94-foot above grade stacks each with equivalent flue diameters of 26.7-feet. Auxiliary equipment will include two fuel gas preheaters which will be used to raise the temperature of the natural gas prior to combustion.

The Project will be a "merchant" plant that will sell electricity in the wholesale market. The plant will be privately financed and will receive its revenues from the sale of electricity. No regulated cost recovery will be sought for the Facility.

Several vendors were contacted and turbine performance specifications were obtained specific to the size of the Facility in terms of electrical output. The Project team evaluated the Project's life-cycle costs, preliminary engineering design, and licensing schedule along with vendor emissions data for NO_x, CO, VOC and PM/PM-10 for each machine, initial equipment delivery schedules, costs, operations and maintenance programs and warranties for each machine.

The review of vendor specifications also considered the proposed Facility site location and recognized the Facility would be affected by the following:

- The Facility site area within New York is a severe non-attainment area for ozone;
- The Facility would result in an emissions increase of greater than 25 tons of NO_x per year and would be subject to ozone non-attainment requirements;
- The Facility would need to comply with LAER provisions; and
- Emissions offsets for NO_x would need to be acquired.

Based upon this assessment a decision was made to proceed with the licensing of the GE 7FA combustion turbine simple-cycle units.

5.4.2 Alternative Analysis Results

This section details the results of the alternative analysis studies that were performed during the development of the Facility. The alternatives analysis considered sites and methods of environmental control.

5.4.2.1 Alternative Sites

Entergy affiliates own three nuclear plants in New York State. The James A. Fitzpatrick Nuclear Power Plant is located in Lycoming, western New York and is owned by Entergy Nuclear FitzPatrick, LLC. Indian Point Nuclear Generating Station Units No. 1 and 2 are located in Buchanan, New York and are owned by Entergy Nuclear Indian Point 2, LLC. (Indian Point 1 is no longer operational). Indian Point 3 is also located in Buchanan, New York and is owned by Entergy Nuclear Indian Point 3, LLC.

Entergy IPPF has evaluated all sites owned by affiliates in New York State, and determined that the proposed Facility site within the Indian Point 3 property was superior for several reasons including:

- The site is geographically located in NYISO Zone H, adjacent to the New York City market. The proposed Facility will assist in improving system reliability within the New York City and Westchester County regions by providing additional electricity during periods of peak demand.

- There are significant transmission constraints between western and eastern New York State (with Lycoming being on the west side of the constraint), such that the James A. Fitzpatrick Nuclear Power Plant site is a less desired location from the standpoint of energy transmission to the New York City and Westchester County market areas compared to the Indian Point 3 location.

- The site is located on a previously disturbed, existing industrial site that has been associated with energy production and the generation of electric power for nearly 40 years. Further, the selected site requires little to no clearing of mature trees.

- The site is located in close proximity to the Algonquin Gas Transmission Company's existing 26-inch and 30-inch natural gas mainlines.

5.4.2.2 Alternative Facility Designs

The design configuration selection for the proposed Facility included evaluation of both simple-cycle and combined-cycle generating facilities as well as various turbine technologies. The selection criteria included market demand, water availability, land availability, facility size, transmission capability, environmental regulations, and Entergy's existing asset position in the Northeast.

A simple-cycle peaking facility was chosen over a combined-cycle facility for several reasons. First, the proposed site was not considered large enough for a combined-cycle facility. Second, Entergy IPPF's market view indicated that there was a need for peaking capacity in this market area, which would also complement Entergy's base load nuclear assets. Third, water was not available for a combined-cycle facility, except from the Hudson River; however, the use of the Hudson River for cooling water is not proposed. Finally, by use of the simple-cycle technology, Entergy IPPF can install the proposed turbines and complete construction on a 12-month schedule. This construction period is significantly shorter than that required for a comparably-sized combined-cycle facility and will allow the proposed Facility to come on line sooner, thereby providing assistance in addressing the state's and region's current and projected shortfall in peak electric generation capacity.

Entergy IPPF had originally considered the use of GE LM6000 combustion turbines for the simple-cycle peaking facility. These units had been chosen primarily because their performance would allow the use of selective catalytic reduction (SCR) in simple-cycle mode to achieve the air emissions limits required in New York. The LM6000 aero-derivative design results in lower exhaust temperatures in simple-cycle than the alternative GE Frame type 7EA and 7FA combustion turbines, enabling the use of the SCR for air emissions controls. However, research conducted by Entergy IPPF during the Facility's planning phase revealed that SCR control for "F Class" turbines in simple-cycle mode could, in fact, be employed. Further, by use of the GE 7FA dry low-NO_x turbine technology, average and peak day water demands on the Village of Buchanan municipal water supply system are reduced by approximately 75 to 80 percent as compared to the original Facility design with GE LM6000 turbines that use water injection for NO_x control and power augmentation.

The size of the Project has been determined by considering an optimal layout for the Facility on available acreage at the Project site. Consideration has been given to existing property boundaries, economies of scale, and the cost of anticipated upgrades to the transmission system.

5.4.2.3 *Alternative Design Options*

A number of alternative design options have been evaluated for the Facility including back-up fuel oil, ammonia supply, stack design, building enclosures, and waste water disposal alternatives.

The Facility will use natural gas only, which is the cleanest burning fossil fuel available. As a result, no evaluation will be performed for back-up fuel oil.

There are a number of available alternatives for providing the ammonia required for the SCR process. The alternatives include anhydrous ammonia, urea, and aqueous ammonia. Anhydrous ammonia was not considered viable because of safety concerns. The use of urea was evaluated and not considered commercially available for a simple-cycle application at this time because a steam source is normally required to break down the urea. There is not an available steam source with the simple-cycle facility design. Aqueous ammonia is commercially available, considered safe when at a 19% concentration and is the industry standard for a simple-cycle facility with SCR.

The Facility was modeled with a number of stack heights. The currently proposed 94-foot stacks result in the lowest possible stack height consistent with minimal air quality impacts, thereby minimizing the potential visual impact of the Facility.

The Facility's objective is to be a zero contact storm water facility. As a result, the Facility's design will include building enclosures. Any process wastewater will be collected and transported off-site for appropriate disposal.

5.4.2.4 *Environmental Considerations*

Based upon the proposed Facility site location in Westchester County, New York, Entergy IPPF recognized that the Facility would be affected by the following:

- Westchester County is non-attainment for ozone;
- The Facility would result in an emissions increase of greater than 25 tons of NO_x per year and would be subject to ozone non-attainment requirements; and
- The Facility would need to comply with LAER provisions and obtain emissions offsets.

In light of these regulatory thresholds as well as the control technology reflected in recently permitted/constructed power generation facilities, the Facility has proposed an engineering design that incorporates the following:

- The use of DLN combustors and SCR as LAER for control of NO_x;
- Utilization of aqueous ammonia as opposed to anhydrous ammonia for the SCR system;
- The use of an oxidation catalyst and combustion controls to minimize incomplete combustion; thereby reducing emissions of CO and VOC;
- The use of clean burning fuel to minimize emissions of SO_2 and PM/PM-10; and
- Advanced combustion controls and continuous emissions monitoring systems.

5.5 Benefits of the Proposed Facility

The proposed Facility will provide competitive electric power and improve reliability of power generation and supply within the region and will bring a number of economic benefits to the residents of Westchester County. Besides improving the efficiency with which citizens of New York meet their energy needs, the beneficial economic impacts include:

- The proposed Facility will pay taxes associated with improvements to the property, sales taxes on locally purchased items supporting the operation of the Facility, and income taxes.

- Construction of the proposed Facility will employ an average workforce of 200 to 250 employees, during a 12-month construction period. The Facility will have a minimal impact on the municipal services supported by the tax dollars it pays.

- The proposed Facility will result in the creation of approximately 5 permanent, highly skilled jobs.

- The Facility will improve utilization of the Facility site as compared to its current use for storage and ancillary parking.

- The Facility results in a net environmental impact far less than the impacts associated with the equivalent power that would need to be generated from existing power stations that are less efficient or do not fire clean fuels.

- Emissions of all criteria pollutants meet federal and state air pollution requirements, as presented in Section 3 of this document.

- The Facility will provide additional generation supply, improving the reliability of the transmission grid during peak demands.

5.6 Conclusions of Analysis

Based upon arguments presented above, the net public gain resulting from the proposed Facility exceeds anticipated impacts associated with the construction and operation of the Indian Point Peaking Facility.

Table 5-1: Calculation of Required Offsets			
Non-Attainment Pollutant	**Potential Emissions (TONS/YR)**	**Proposed Offset Ratio**	**Required Offsets (Rounded Up)**
Nitrogen Oxides	230.0	1.3:1	299

6.0 TITLE IV SULFUR DIOXIDE ALLOWANCE REQUIREMENTS

Based upon the regulatory analysis presented in Section 3, the Facility is required to obtain SO_2 allowances in order to comply with the requirements of the Acid Rain regulations as presented in 40 CFR Part 72 and 40 CFR Part 73.

6.1 Calculation of SO_2 Allowances Required

At the end of each operating year, affected emission units must hold in their compliance subaccounts a quantity of allowances equal to or greater than the amount of SO_2 emitted during that year. To account for emissions for the previous year, such units must finalize allowance transactions and submit them to U.S. EPA by March 1 (February 29 in a leap year) to be recorded in their unit accounts. The quantity of emissions is determined in accordance with the monitoring and reporting requirements described in 40 CFR Part 75.

After the March 1 deadline and the recording of the final submitted transfers, U.S. EPA deducts allowances from each unit's compliance subaccount in an amount equal to its SO_2 emissions for that year. If the unit's emissions do not exceed its allowances, the remaining allowances are carried forward, or banked, into the next year's subaccount, which then becomes the current compliance subaccount. If a unit's emissions exceed its allowances, the unit must pay a penalty and surrender allowances for the following year to U.S. EPA as excess emission offsets. Unless otherwise provided in an offset plan, U.S. EPA deducts allowances from the compliance subaccount in an amount equal to the excess emissions.

The Facility will be required to obtain SO_2 allowances. Based upon potential emission calculations, the Facility will be required to purchase less than 23 allowances per year.

6.2 Sources of Allowances

In addition to annual allocations from the U.S. EPA, allowances are also available upon application to three U.S. EPA reserves. In Phase I, units can apply for and receive additional allowances by installing qualifying Phase I technology (a technology that can be demonstrated to remove at least 90 percent of the unit's SO_2 emissions) or by reassigning their reduction requirements among other units employing such technology. A second reserve provides allowances as incentives for units achieving SO_2 emissions reductions through customer-oriented conservation measures or renewable energy generation. The third reserve contains allowances set aside for auctions, which are sponsored yearly by U.S. EPA. In addition, allowances are given as incentives for utilities that replace boilers with new, cleaner and more efficient technologies.

Units that began operating in 1996 or later (such as the proposed Facility) will not be allocated allowances. Instead, they will have to purchase allowances from the market or from the U.S. EPA auctions and direct sales to cover their annual SO_2 emissions.

Allowances may be bought, sold, and traded by any individual, corporation, or governing body, including brokers, municipalities, environmental groups, and private citizens. The primary participants in allowance trading are officials designated and authorized to represent the owners and operators of electric utility plants that emit SO_2. Other potential participants are utility power pools, or groups of units choosing to aggregate some or all of the allowances held by the individual units within the pool. The parties involved in the pool determine the details of these allowance-pooling arrangements. There is an ample supply of SO_2 allowances available to the Facility.

6.3 Phase II Acid Rain Permit Application

A copy of the draft Phase II Acid Rain permit application is included in Appendix E.

7.0 AIR QUALITY MODELING ANALYSIS

7.1 Introduction and Summary

The proposed Facility will have potential annual emissions of all criteria pollutants less than the PSD major source threshold of 250 tons under 40 CFR 52.21(b)(23). The proposed Facility is required to obtain a NYCRR Part 201 Air Permit. Under the Part 201 requirements, it must be demonstrated that emissions of each criteria pollutant will not prevent attainment or maintenance of the National Ambient Air Quality Standards (NAAQS) and New York Ambient Air Quality Standards (NYAAQS), and comply with PSD Class II air quality increments (as a PSD minor source).

The proposed Facility will be located in an area (Westchester County) currently designated as attainment for CO, SO_2, NO_x, and PM-10. However, the area is designated as severe non-attainment for ozone (O_3). (Note: Westchester County has recently been determined to be in "attainment" for CO. However, Entergy IPPF understands that the redesignation process has not been completed as a regulatory matter. As such, Entergy IPPF is moving forward as if certain requirements related to Non-attainment New Source Review for CO are still in effect.) Therefore, facilities emitting more than 25 tons per year of NO_x or VOC and 100 tons per year of CO are subject to NNSR rules for these pollutants. NNSR requirements include the requirement to meet LAER levels and the need to obtain emission offsets. Potential emission rates indicate that the proposed Facility will be subject to NNSR for NO_x, but not for VOC.

Results of the air quality analyses indicate that the proposed Facility will have an insignificant impact on the surrounding air quality (i.e., the maximum modeled impacts were less than the U.S. EPA defined SILs). Hence, no further NAAQS and PSD Class II increment analyses were required. Therefore, the proposed Facility is not subject to PSD review. However, additional analyses including impacts on the surrounding soil, vegetation, and visibility from the proposed Facility that are typically required by the PSD review process will be included in the Article X Application.

7.2 Modeling Methodology

Dispersion modeling was performed consistent with the procedures found in NYSDEC's Air Guide Series and U.S. EPA documents: *Guideline on Air Quality Models (Revised)* (U.S. EPA, 2001), *New Source Review Workshop Manual (Draft)* (U.S. EPA, 1990), and *Screening*

Procedures for Estimating the Air Quality Impact of Stationary Sources (U.S. EPA, 1992). A detailed discussion on the modeling methodology, which was used for the air quality analysis, is contained in the modeling protocol submitted to NYSDEC for review on March 22, 2002 and approved by the NYSDEC in an April 26, 2002 letter to Anthony Letizia of TRC. A copy of this approval letter is included in Appendix C of this application.

As described in the modeling protocol, the following methodology was employed in the assessment:

- Screening of turbine operating scenarios with refined modeling using onsite sequential hourly meteorology to identify the worst case operating conditions to be used for subsequent modeling, if necessary;
- Determination of the Project area of impact (if any) with refined modeling;
- Including condensable particulate (PM-10) in the modeled PM-10 emission rates; and
- Modeling the concurrent operation of the turbines and fuel gas heater using the worst-case turbine operating scenario exhaust parameters and emission rates for each criteria pollutant (i.e., CO, SO_2, PM-10, and NO_x).

Specifically, results of the screening of turbine operating scenarios with refined modeling to identify the worst case operating conditions were compared to the SILs established in the NSR regulations. These results were less than the SILs for all pollutants and averaging periods. When the turbines are operating, one of the two fuel gas heaters (the second heater is a back-up) could also be operating, thus the worst-case turbine operating scenario was modeled with a proposed fuel gas heater to determine the proposed Facility's overall maximum modeled concentration for each pollutant and averaging period. Results of modeling the entire Facility also showed that the maximum modeled concentrations were less than the SILs for all pollutants and averaging periods. Thus, there were no areas of impact and no subsequent multiple major source cumulative modeling was required.

7.3 Surrounding Area and Land Use

The proposed Facility will be constructed on approximately 5 acres within the existing 102-acre Indian Point 3 property, located in the Village of Buchanan, Westchester County, New York. The Indian Point 3 property is part of an energy-production complex that comprises approximately 239 acres. Currently vacant and used for temporary storage of various maintenance materials and equipment and parking, the key features of the proposed Facility site include its industrial nature, the amount of acreage available, its proximity to the Algonquin Gas Transmission Company's interstate natural gas mainlines, and its proximity to the Buchanan 138-kV electrical substation.

Located on the east bank of the Hudson River in the Village of Buchanan, approximately 35 miles north of New York City, terrain rises very rapidly northwest of the proposed Facility site. Across the Hudson River, approximately 2 miles northwest of the site, Bald Mountain (on Dunderberg Mountain) rises to an elevation of 1,120 feet. Approximately 4 miles northwest of the site, in Bear Mountain State Park, Bear Mountain rises to an elevation of 1,284 feet. Less rugged terrain prevails east of the site. The proposed Facility will be located at approximately 41° 15' 52'' North Latitude, 73° 57' 21'' West Longitude. The approximate Universal Transverse Mercator (UTM) coordinates of the Facility are 587,460 meters Easting, 4,568,417 meters Northing, in Zone 18.

The elevation (topography) of the site has been altered due to construction of Indian Point 3 and is relatively uniform. Site elevation is approximately 119 feet above mean sea level (MSL). Topography proximate (within 1 kilometer) to the proposed Facility varies from river level at the Hudson River to approximately 145 feet above MSL just northeast of the site. The nearest location where terrain rises above the proposed stack top is approximately 2 kilometers northwest of the proposed Facility, at an elevation of 214 feet above MSL. Figure 1-1 presents the proposed Facility's location on a U.S. Geological Survey (USGS) 7.5-minute topographic map.

A land use classification analysis was performed to determine if urban or rural dispersion parameters should be used in quantifying ground-level concentrations. The analysis conforms to the procedures contained in the A.H. Auer paper *Correlation of Land Use and Cover with Meteorological Anomalies* (Auer, 1978) and U.S. EPA's *Guideline on Air Quality Models (Revised)* (U.S. EPA, 2001). This procedure involves determining the percentages of various industrial, commercial, residential, and agricultural/natural areas within a 3-kilometer radius circle centered on the proposed site in order to assess the land use around the proposed Facility. Essentially, if more than 50 percent of the area within this circle is designated I1, I2, C1, R2 and R3 (industrial, commercial, and compact residential), urban dispersion parameters should be used; otherwise, the modeling should use rural dispersion parameters.

The predominant land uses are water surfaces (A5) and agricultural/woodland (A2/A4) at 35 and 29 percent, respectively. The other rural land use within 3-kilometers of the proposed Facility is common residential at 3 percent. Based on the land use analysis, greater than 50 percent of the land usage is considered a rural land use and, as such, the air quality analysis was performed using dispersion coefficients for rural environments. The land use distribution within 3-kilometers of the proposed site is shown in Figure 7-1.

7.4 Model Selection and Inputs

The Industrial Source Complex Short-Term (ISCST3) model (version 02035) was used to assess the air quality impacts from the proposed Facility. Throughout this modeling application, "ISCST3" refers to Version 02035 unless otherwise specified. The ISCST3 model was applied in accordance with the recommendations made in U.S. EPA's *Guideline on Air Quality Models (Revised)* (U.S. EPA, 2001).

The ISCST3 model is a Gaussian plume model capable of calculating concentrations in simple (below stack top), intermediate (above stack top and below final plume rise), and complex (above final plume rise) terrain. According to the U.S. EPA's *Guideline on Air Quality Models (Revised)* (U.S. EPA, 2001), the ISCST3 model can only be used to calculate concentrations in intermediate and complex terrain if on-site meteorological data for one continuous year or more are available. Because Entergy IPPF used five years of on-site meteorological data in the modeling analysis, the ISCST3 model was used to calculate concentrations in simple, intermediate, and complex terrain.

In intermediate terrain (terrain with elevations above stack top and below final plume rise), the ISCST3 model in default mode will use two algorithms for determining the concentration at the receptors. The default ISCST3 algorithm truncates the terrain elevation to stack top and performs a calculation with the simple terrain elevation. However, ISCST3 also includes the COMPLEX I elevated terrain screening algorithm which handles dispersion in complex terrain in a different fashion. If the receptor is at an elevation above stack top but below the height of the final plume rise, then ISCST3 will calculate a concentration based on both the default ISCST3 method and the COMPLEX I method and present the higher of the two concentrations. ISCST3 will use only the COMPLEX I calculations for receptors at elevations above the final plume rise.

Since the ISCST3 model did not yield concentrations above the SILs in complex terrain, more refined complex terrain models, such as the U.S. EPA CTSCREEN (version 94111) complex terrain model, were not used to refine the complex terrain impacts.

ISCST3 includes various input and output options. Additional options are available for specific methods to be used in plume model equations. The model was applied using regulatory default (DFAULT keyword) options. These include the following:

- Stack Tip Downwash. U.S. EPA recommends this option for use in regulatory applications. When this option is implemented, a height increment is deducted from the physical stack height before computing plume rise, as recommended by Briggs (1974). The height increment to be deducted from the physical stack height depends upon the ratio of stack exit velocity to wind speed and is equal to 2d [1.5 – v_s/u], where v_s is the stack exit velocity, u is the wind speed, and d is the inside stack diameter. If v_s/u is greater than 1.5, the height increment is zero.

- Plume Rise. With this option, final plume rise would be used for calculating the plume height to be used in estimating ground-level concentrations at all receptors. However, the gradual plume rise algorithm was used since Entergy IPPF's proposed stacks will be below GEP height. The selection of this option is consistent with U.S. EPA guidelines.

- Buoyancy-Induced Dispersion. This option causes modifications to the dispersion coefficient (σ_y and σ_z) calculations that account for enhanced dispersion due to turbulence caused by plume buoyancy (Pasquill, 1976). This results in a simulated plume with greater horizontal and vertical extent than would be simulated considering dispersion from ambient turbulence only. This option is applied only near the source, before the plume reaches its final height. It is a recommended option for regulatory applications.

- Vertical Potential Temperature Gradient. The vertical potential temperature gradient is used to calculate the stability parameters used in plume rise equations for stable conditions. Default values appropriate for rural applications were used in the ISCST3 modeling.

- Wind Profile Exponents. ISCST3 uses a power-law extrapolation of wind speeds from measurement height to stack height. Default values appropriate for rural applications were used in the ISCST3 modeling.

- Decay. An exponential decay term may be included in ISCST3 modeling to simulate removal processes. The decay coefficient may be universally applied to all calculations or entered with meteorological data on an hourly basis. No decay was applied in this analysis.

- Wake Effects. Building wake effects may be simulated using procedures suggested by Huber and Snyder (1976) and Huber (1977). When the stack height is less than the building height plus one half the lesser of the building height or width, wake effects are simulated using procedures suggested by Schulman and Hanna (1986) and based on the work of Scire and Schulman (1980). Since the Facility will employ non-GEP stacks, wake effects were considered by using BPIP and directional dependent building dimensions in ISCST3.

- Calm Processing. When the calm processing option is implemented, calm conditions are handled according to methods developed by the U.S. EPA. When a calm is detected in the meteorological data, or the data are missing, the concentrations at all receptors are set to zero, and the number of hours being averaged is never less than 75 percent of the averaging time.

Rural dispersion coefficients and terrain heights for each receptor were also input to the ISCST3 model.

7.4.1 Source Parameters and Emission Rates

The proposed Facility will consist of two natural gas fired only GE Frame 7FA combustion turbines with a maximum heat input rate of 1,979 mmBtu/hr, HHV, each. Auxiliary equipment at the proposed Facility will include two fuel gas heaters, of which, only one will operate at any time (the second one is a back-up).

Each turbine will employ dry low-NO_x (DLN) burners and SCR to minimize emissions of NO_x. An oxidation catalyst will be used to control emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The total nominal electrical power from the simple-cycle Facility will be approximately 330 MW. Upon leaving the SCR system, the turbine exhaust will be directed to the atmosphere through two individual 94-foot stacks.

The combustion turbines will fire only natural gas. The natural gas is assumed to have a Higher Heating Value (HHV) of approximately 1,020 Btu/standard cubic foot (SCF) and is assumed to contain 0.5 grains of sulfur per 100 SCF on an annual average basis. Natural gas will be supplied from the existing Algonquin natural gas pipeline via a proposed tie-in line.

The maximum heat input (1,979 mmBtu/hr, HHV) for the GE Frame 7FA turbines occurs at -10 degrees Fahrenheit (°F) ambient temperature. Because turbine performance and emissions are affected by ambient temperature, three ambient temperatures (-10°F, 50°F, and 100°F) were included in the turbine load analysis to reflect the minimum, average, and maximum ambient temperatures for the area. These ambient temperatures are consistent with NYSDEC guidance received at the October 15, 2001 preapplication meeting.

The two simple-cycle combustion turbines will serve as peaking units and supply power during periods of high power demand. Depending on power demand, either one or both turbines could operate at any given time. Each turbine will be capable of operating between 50 percent and 100 percent load. Therefore, the load screening analysis for the turbines has determined impacts for the turbine operating at 50%, 75%, and 100% load conditions. These conditions represent the minimum, midpoint, and maximum operating loads. Because the performance of combustion turbines varies with ambient temperature, the three turbine operating loads were modeled for three ambient temperatures (-10°F, 50°F, and 100°F). In addition, the units will be equipped with a fogging-type inlet air cooling system to further boost power and efficiency on hot days. Thus, ten operating scenarios were modeled to reflect these different cases.

Exhaust characteristics and potential emission rates for the turbine stack for all ten operating scenarios are provided in Table 7-1.

Each 11.8 mmBtu/hr, HHV fuel gas heater will exhaust to two (2) stacks (for a total of four (4) stacks). The four (4) stacks will be contained within a single 94-foot outlet. Only one of the fuel gas heaters will operate at any given time, as the other will serve as a back-up. Table 7-2 presents the stack parameters and potential emission rates for the fuel gas heaters.

7.4.2 Start-Ups

As was previously noted, the Facility will be dispatchable and will undergo periodic cycles of start-up and shutdown. Start-up is defined as the period of time during which the combustion turbine has not reached 50% load or greater. Worst-case start-ups refer to starts made more than 12 hours after shutdown and will not exceed 20 minutes per occurrence (under normal conditions). Start-up is complete when emissions are within NO_x/CO limits per CEM.

PM/PM-10 and SO_2 air quality impacts will not be adversely affected by these operations because the emissions of PM/PM-10 and SO_2 are primarily a function of load:

- SO_2 emissions are directly related to fuel sulfur content and fuel usage. At less than full load, less fuel is consumed. Therefore, less SO_2 is emitted.

- Similarly, emissions of PM/PM-10, which forms from impurities in the fuel as well as from contaminants in the inlet air, (air intake is maximized at full load) are reduced during these operations.

NO_x emissions may increase due to changes in the combustion efficiency during these transition periods and due to the SCR being out of service or providing reduced NO_x reduction until the catalyst reaches optimum operating temperature. Since the NO_2 standard is calculated on an annual basis, it will not be affected by conditions whose duration is limited to approximately 87 out of 8,760 hours per year (i.e., 260 starts per year times 20 minutes per start).

The only pollutant, for which a change in concentrations could result, primarily as a result of combustion inefficiency during the transition period, is CO. CO has a 1-hour and 8-hour standard. Start-up transition times last a maximum of 20 minutes and thus, can affect CO 1-hour and 8-hour concentrations. Therefore, a modeling analysis was conducted to assess the CO 1-hour and 8-hour concentrations during start-ups.

Start-up CO emissions presented in Table B-3 (Appendix B) were modeled from the turbine. The exhaust temperatures and velocities used to model the start-up emissions were based on turbine start-up performance curves. A representative average start-up exhaust temperature and velocity were calculated to be 612.8 Kelvin (K) and 6.58 meters per second (m/s), respectively.

Because the start-up duration is approximately 20 minutes, the maximum 1-hour and 8-hour CO concentrations were determined based on the combination of the start-up conditions for the appropriate amount of time, the worst-case 1-hour and 8-hour CO operating scenario determined in the turbine load analysis (case 1, which has the turbine at 100 percent load at an ambient temperature of -10°F) for the remaining period of time in the 1-hour and 8-hour averaging periods, respectively, and the operation of one of the fuel gas heaters.

7.4.3 Good Engineering Practice Stack Height Analysis

U.S. EPA's *Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations)*, (U.S. EPA, 1985) provides specific guidance for determining GEP stack height and for determining whether building downwash will occur. GEP is defined as "the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain "obstacles"."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which adverse aerodynamics (downwash) are avoided.

The U.S. EPA GEP stack height regulations specify that the GEP stack height be calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

where: H_B = the height of adjacent or nearby structures, and
L = the lesser dimension (height or projected width of the adjacent or nearby structures)

The proposed Facility will be designed with two individual combustion turbine stacks and four collocated fuel gas heater stacks. The four (4) stacks will be contained within a single 94-foot outlet. Studies have been conducted to determine a stack height that will be sufficiently low enough to minimize visibility of the stack, yet tall enough to result in minimal air quality concentrations. The results of these studies indicate that the optimum stack height to minimize visual impacts and air quality concentrations was 94 feet above grade level (AGL), which is below the GEP height determined from the proposed structures at the Facility site.

The controlling structure for the proposed turbine and fuel gas heater stacks is the upper level of the main generator building. This structure will have a height of 62.1 feet AGL and would result in a GEP stack height of 155.2 feet AGL. At 94 feet AGL, the simple-cycle turbine stacks and fuel gas heater stacks will be 1.5 times the upper level of the main generator building height, outside the turbulent cavity zone. A stack height of at least 1.5 times the height of the controlling structure is sufficient to avoid entrainment of the emissions into the recirculation zone (or cavity), behind the structure.

Because the proposed turbine stacks and fuel gas heater stacks will be non-GEP, direction-specific building downwash parameters were input to the ISCST3 model. The U.S. EPA Building Profile Input Program (BPIP, version 95086) was used to determine the directionally dependent building dimensions for input into the modeling analysis. Table 7-3 presents the GEP stack height analysis for the proposed turbine stacks. A detailed plot plan of the proposed Facility has been provided in Figure 2-2.

Air Guide 26 states that it is NYSDEC policy that "proposals to construct or modify a source ensure that the associated stack be designed according to formula GEP height specifications."

The following detailed explanations are presented below to justify Entergy IPPF's proposal to build non-GEP stacks rather than formula GEP stacks:

- Visual and Aesthetic Impacts: Entergy IPPF seeks to minimize visual and aesthetic impacts by building 94 foot non-GEP stacks that will blend in with the surrounding industrial landscape formed by Indian Point 1, 2, and 3, the Wheelabrator Westchester Facility, and the LaFarge Gypsum Buchanan Plant. The proposed Facility will be designed to be compatible with the visual characteristics of the adjacent and surrounding areas by taking advantage of existing grades and surrounding buffer areas. A 94 foot stack is in the same general size range as the trees on the Indian Point property which will provide shielding from aesthetic impacts, whereas a stack greater than 150 feet will be above the trees in the area. Visual impact is an important consideration at this site not only for the local residents in the nearby residential area, but also because the site is located just south of the Hudson Highland's Scenic Area of Statewide Significance.

- Aviation Impact: Due to the height of existing structures and transmission towers in the immediate vicinity of the proposed Facility, Entergy IPPF does not anticipate conflicts with general aviation services due to the proposed 94 foot non-GEP stacks.

- Air Quality Impacts due to GEP Stacks: As mentioned above and discussed in detail below, detailed modeling of the proposed Facility with 94 foot non-GEP stacks has shown that maximum plant impacts will be below SILs and well below applicable NAAQS. The GEP stack height has been determined to be 155.2 feet. An air quality modeling analysis was performed to determine what affect GEP stacks would have on modeled concentrations. For 1-hour CO, air quality concentrations may be reduced from 0.54% of the CO SIL to 0.45% of the CO SIL and for 8-hour CO, air quality concentrations may be reduced from 1.0% of the CO SIL to 0.87% of the CO SIL. For 3-hour SO_2, air quality concentrations may be reduced from 10.3% of the SO_2 SIL to 8.6% of the SO_2 SIL and for 24-hour SO_2, air quality concentrations may be reduced from 8.6% of the SO_2 SIL to 7.2% of the SO_2 SIL. Annual SO_2 concentrations may be reduced from 1.5% of the SO_2 SIL to 1.1% of the SO_2 SIL. For 24-hour PM-10, air quality concentrations may be reduced from 83.1% of the PM-10 SIL to 68.0% of the PM-10 SIL. Annual PM-10 concentrations may be reduced from 17.7% of the PM-10 SIL to 13.5% of the PM-10 SIL and annual NO_2 concentrations may be reduced from 35.8% of the NO_2 SIL to 15.6% of the NO_2 SIL. Entergy IPPF believes these concentration reductions are not sufficiently large to justify adding an additional 61.2 feet to the heights of the proposed stacks, at the expense of surrounding visual quality.

Entergy IPPF believes that the insignificant changes in impacts associated with raising the stacks to a GEP height versus the increased visual impact associated with a taller stack justify the building of proposed 94 foot non-GEP stacks rather than 155.2 foot formula GEP stacks.

7.4.4 *Meteorological Data*

Entergy IPPF used 5 years of hourly meteorological data collected by the meteorological tower at Indian Point 3 from January 1996 through December 2000 in the modeling analysis. This tower has been collecting data at the site for many years and is designed and operated in accordance with stringent United States Nuclear Regulatory Commission (NRC) meteorological monitoring guidelines that are similar to U.S. EPA guidelines. Table 7-4 presents a comparison of these two guidelines. The tower location is roughly the same elevation as the proposed site. Tower siting with respect to surrounding terrain influences is also similar to the terrain influencing the proposed site. The tower is located near the proposed stack locations. Data were recorded at 10 meters, 60 meters, and 122 meters AGL on the tower. The 10-meter data were used in the modeling analysis, as these data are from the tower level closest to the top of the proposed stacks.

The data quality assurance and quality control procedures used during the data collection period included weekly visual inspections of all equipment, gross comparison of recorded data versus real conditions, semiannual electronic zero/span checks, and semiannual instrument and accuracy tests with independent equipment and standards. Overall data recovery for the proposed monitoring period ranged from 99.3% to 99.8%, which exceeds the 90% U.S. EPA PSD monitoring guideline requirement. Based upon the above, the Indian Point 3 onsite data meets the siting, data recovery, and quality assurance criteria of the U.S. EPA PSD Monitoring Guidelines.

The Indian Point 3 meteorological data was collected on-site; therefore, it is appropriate to determine concentrations in both simple and complex terrain using the ISCST3 model. Because the meteorological data was collected on-site, it is the most representative, available data for use in assessing air quality concentrations due to the proposed Facility. Therefore, the Indian Point 3 meteorological data was used for the air quality modeling analyses that were required for the proposed Facility.

In addition to on-site meteorological data, the air quality modeling required concurrent years of twice-daily upper air meteorological data that were used to calculate the mixing height in the atmosphere for use by the ISCST3 model. Upper air observations are taken by the National Weather Service (NWS) at a limited number of locations throughout the United States. The NWS upper air observation stations closest to the Facility site with available data for 1996-2000 are Albany, New York, and Brookhaven National Labs, Upton, New York. A review of summarized mixing height data for 62 upper air stations in the United States, which was prepared by Holzworth in *Mixing Height, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States* (Holzworth, 1972) indicates that the Albany mixing height data are the most representative of site conditions, and thus these data were used in the modeling study.

Concurrent years of surface meteorological data, in addition to both the on-site and mixing height data, were also needed to produce a model-ready meteorological data file. Stewart International Airport, approximately 7 kilometers west of Newburgh, New York, and 29 kilometers northwest of the Facility site, represents the closest representative NWS station with meteorological data available for modeling purposes.

The three meteorological datasets (on-site, mixing height, and surface) were processed using the Meteorological Processor for Regulatory Models (MPRM, version 99349). MPRM creates a model-ready meteorological file that is used by ISCST3.

7.4.5 Receptor Grid

The ISCST3 model requires receptor data consisting of location coordinates and ground-level elevations. The receptor-generating program, AERMAP, was used to develop a complete receptor grid to a distance of 15 kilometers from the proposed Facility. AERMAP uses digital elevation model (DEM) data obtained from the USGS. The 1-degree (3-arc-second) DEM files were obtained for an area covering at least 15 kilometers in all directions from the proposed Facility. AERMAP was run to determine the representative elevations for each receptor.

7.4.5.1 Basic Receptor Grid

A polar receptor grid consisting of receptors located along radials every 10 degrees from 10 degrees through 360 degrees (north) was used. The receptors were spaced along the radials every 100 meters from the center of the Facility to 3.5 kilometers, every 250 meters from 3.75 kilometers to 8 kilometers, and every 1-kilometer from 9 kilometers to 15 kilometers. In addition, receptors were placed every 25 meters along the fence line that precludes general public access. Fence line receptors were assigned an elevation of 120 feet above MSL. Any polar receptors located within the fence line were removed.

If the maximum-modeled concentrations had been located in an area beyond the 100 meter spaced receptors, a Cartesian grid of 100 meter spaced receptors would have been placed around the initial maximum-modeled concentration location to ensure the maximum-modeled concentration was located. Furthermore, if concentrations had been increasing at the 15,000-meter ring, additional rings would have been added to determine the distance at which concentrations begin to decrease.

The minimum receptor distance specified by the U.S EPA Modeling Guideline is 100 meters. Since the maximum modeled concentrations for all pollutants and averaging periods were located within the 100 meter spaced receptor area (i.e., within 3.5 kilometers of the proposed Facility), no further refinement of the grid was required. Figure 7-2 shows the receptor grid near the proposed Facility.

7.4.5.2 Sensitive Receptors

A list of sensitive receptors within 4 kilometers of the Facility site was developed for inclusion in the modeling analysis. USGS topographic maps and the Westchester County Emergency Response Plan for Indian Point were used to determine the sensitive receptor locations. Sensitive receptors included day care and nursery schools, elementary, middle, and high schools, and other community facilities. Information on these receptors can be found in Table 7-5, which includes the name of the facility, location coordinates, elevation of the terrain above MSL, and distance and direction from the proposed Facility. Sensitive receptor elevations were determined from USGS quadrangle maps.

7.5 Modeling Results

Modeling was conducted to assess impacts of the proposed Facility and demonstrate that it would not cause an exceedance of the NAAQS or PSD increments. Results of these analyses are presented in following sections. All modeling input and output files used to conduct these analyses have been included electronically on CD-ROM in Appendix G.

7.5.1 Load Analysis Results

To determine the worst case operating scenario for the proposed turbines, a load analysis was conducted for three operating loads (50%, 75%, 100%), three ambient temperatures (-10°F, 50°F, and 100°F), one fuel type (natural gas), and inlet fogging. Thus, a total of ten cases were modeled in the load analysis for the proposed turbines.

The worst case turbine operating scenarios (i.e., operating scenarios which yielded the maximum modeled concentrations) for the ground-level receptors were: Case 1 (operating at 100% load at -10°F) for 1-hour and 8-hour CO impacts and 3-hour and 24-hour SO_2 impacts, Case 2 (operating at 75% load at -10°F) for annual SO_2, Case 3 (operating at 50% load at -10°F) for annual NO_2 impacts, and Case 10 (operating at 50% load at 100°F) for 24-hour and annual PM-10 impacts.

The maximum ground-level concentrations were located within the area of 100 meter spaced receptors; therefore, no refined receptor grids surrounding each of the maximum locations were necessary. Results of the turbine load analysis are shown in Table 7-6. The table shows that maximum concentrations of all pollutants for all averaging periods are less than their respective SILs. Complete results of the turbine load analysis are presented in Appendix F.

7.5.2 *Significance Analysis*

To determine the overall proposed Facility maximum modeled concentrations for all pollutants and averaging periods, the worst case turbine operating scenarios presented above were then modeled along with the fuel gas heater. Because only one fuel gas heater will operate at any given time, emissions from one fuel gas heater were modeled along with the turbines.

Results of modeling the worst case turbine operating scenario along with the fuel gas heater are presented in Table 7-7. Inspecting the table reveals that the maximum calculated concentrations of all pollutants for all averaging periods are less than the SILs and NAAQS. Also presented in Table 7-7 are the distance, direction, and year of the maximum modeled concentrations. The maximum modeled concentrations from the proposed Facility were located within 3.5 kilometers of the site in an area of 100 meter spaced receptors; therefore, no refinement of the receptor grid was necessary. Because the pollutant-specific maximum modeled concentrations are less than their respective SILs, no multisource modeling (i.e., NAAQS and PSD Increment) analyses are required.

Figures 7-3 through 7-10 show contours of the maximum modeled concentrations due to the proposed Facility for each pollutant and averaging period out to five miles from the proposed Facility. The maximum 1-hour and 8-hour CO concentrations are shown in Figures 7-3 and 7-4, respectively. The maximum 3-hour SO_2 concentrations are shown in Figure 7-5, while Figure 7-6 presents the maximum 24-hour SO_2 concentrations and Figure 7-7 presents the maximum annual SO_2 concentrations. The maximum 24-hour and annual PM-10 concentrations are shown in

Figures 7-8 and 7-9, respectively, and the maximum annual NO_2 concentrations are shown in Figure 7-10. As shown in the figures, the overall maximum modeled concentrations decrease with distance from the proposed Facility. All of the maximum modeled concentrations are less than their respective SILs and well below their respective NAAQS.

7.5.3 Start-Up Analysis

The maximum 1-hour and 8-hour CO concentrations were calculated assuming the starts lasted approximately 20 minutes. For the remaining time during the 1-hour and 8-hour periods, the turbines were assumed to be operating at the worst-case 1-hour and 8-hour CO operating scenario determined in the turbine load analysis. This operating case was case 1 (100% load at -10°F). The hourly emissions for the start-ups and worst-case operating scenario were scaled to account for the duration of each during the 1-hour and 8-hour periods, respectively. The operation of one of the fuel gas heaters was also included in the analysis.

Results of the 1-hour and 8-hour CO modeling analysis for start-ups indicated that the maximum modeled CO concentrations for start-ups were less than the 1-hour SIL of 2,000 ug/m^3 and the 8-hour SIL of 500 ug/m^3. The maximum modeled 1-hour CO concentration for a start was 183.4 ug/m^3 and the maximum 8-hour CO concentration for a start was 16.3 ug/m^3. Thus, no further modeling was necessary.

7.5.4 Class I Analyses

There are no Class I areas located within 100 kilometers of the proposed Facility. The nearest Class I areas to the proposed Project site are the Lye Brook Wilderness Area, in Vermont, and Edwin B. Forsythe National Wildlife Refuge at Brigantine, New Jersey, located approximately 213 kilometers to the north-northeast and approximately 190 kilometers to the south, respectively. Thus, no Class I modeling analyses were conducted.

7.5.5 Impacts on Industrial, Commercial, and Residential Growth

The proposed Facility's location within an energy-producing complex will result in minimal impact to existing services, traffic, and infrastructure. The proposed Facility will utilize natural gas, which will be brought in by a tie-in to the Algonquin Gas Transmission Company's interstate natural gas mainline, and will be used for the efficient production of electricity, which will be exported by a new power line to the Buchanan 138-kV electrical substation. The existing roads and services will easily be able to handle the 5-person workforce, who will be spread over

2 shifts. A transient workforce, drawn from a large surrounding area, will be used during the construction phase of the Project, however, it is anticipated that few, if any, construction workers will permanently relocate to the surrounding communities. Field construction activities are expected to have an approximate 12-month duration.

The proposed Facility is designed to result in very low emission levels of air contaminants. The proposed Facility will typically operate during periods of peak energy demand and the electricity generated by the Facility will be directed to the power distribution system in New York. Thus, this increased power supply will not attract new industry to any specific area. Finally, since the air emissions from the proposed Facility are so low as to result in less than significant impacts, new industry desiring to locate in the area will not be prohibited due to high air pollution levels caused by the proposed Facility. Therefore, the proposed Facility should have no effect on either existing or future industrial, commercial, or residential growth in the region.

7.5.6 Sensitive Population Receptor Impact Analysis

In order to adequately assess the potential impact of the proposed Facility on sensitive populations (e.g., children, elderly and sick individuals), a separate modeling analysis was performed to examine the maximum impacts at areas of sensitive population. Specifically, such sensitive population areas would include day care and nursery schools, elementary, middle, and high schools, and other community facilities where a large number of potentially air quality sensitive individuals may be residing for an appreciable amount of time. The study area within 4 kilometers around the proposed Facility was examined. Table 7-8 presents the maximum air quality concentrations calculated by ISCST3 that would be experienced by these locations during operation of the proposed Facility. As shown on Table 7-8, the maximum concentrations are orders of magnitude below the applicable NAAQS and SILs, such that these sensitive locations will not experience an adverse air quality impact as a result of the operation of the proposed Facility.

7.6 Modeling Data Files

A listing of the modeling data files for the turbine load analyses used to determine the worst case operating scenarios is included on a CD-ROM contained in Appendix G. Also included on the CD-ROM are all of the modeling files for the significance, startup, and sensitive population analyses. The CD-ROM is included with the NYSDEC copy of this document that is addressed to Mr. Leon Sedefian.

7.7 References

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Table 7-1: Simple-cycle Combustion Turbine Stack Exhaust Parameters and Emission Rates[a]									
Case	Fuel Type	Ambient Temperature (°F)	Turbine Load (%)	Exhaust Temperature (K)	Exhaust Velocity (m/s)[b]	Potential Emission Rates (lb/hr)[c]			
						NO_x	CO	PM-10	SO_2
1	Gas	-10	100	783.2	24.4	26.63	10.94	22.79	2.77
2	Gas	-10	75	783.2	20.0	21.76	8.94	21.94	2.23
3	Gas	-10	50	783.2	16.9	18.47	7.59	21.23	1.76
4	Gas	50	100	783.2	23.6	25.60	10.52	22.41	2.53
5	Gas	50	75	783.2	19.6	21.26	8.73	21.68	2.05
6	Gas	50	50	783.2	16.9	18.33	7.53	21.04	1.64
7	Gas	100	100[d]	783.2	22.7	23.69	9.73	22.04	2.29
8	Gas	100	100	783.2	22.2	23.33	9.58	21.91	2.20
9	Gas	100	75	783.2	19.2	20.14	8.28	21.36	1.85
10	Gas	100	50	783.2	16.2	17.05	7.01	20.76	1.46

[a]The turbines will have individual 18-foot by 31-foot rectangular stacks with a height of 94 feet above grade. The base elevation of the stacks will be 119 feet above mean sea level.
[b]Exhaust velocities calculated using an effective stack diameter of 26.65 feet (8.12 meters).
[c]Emissions are per turbine.
[d]Evaporative cooler ON.

Table 7-2: Fuel Gas Heater Exhaust Parameters and Potential Emission Rates		
Parameter	**Units**	**Value**
Stack Parameters		
Stack Height	meters	28.65
Stack Diameter	meters	0.31
Effective Stack Diameter[a]	meters	0.44
Exhaust Temperature	K	702.6
Exit Velocity	m/sec	17.7
Emission Rates		
NO_x	g/s	0.16
CO	g/s	0.06
SO_2	g/s	0.002
PM-10	g/s	0.01

[a] Effective stack diameter determined since each fuel gas heater will exhaust to 2 stacks (for a total of 4 stacks). The four stacks will be contained within a single outlet. Therefore, for modeling purposes, the stack diameter of 12.25 inches (0.31 meters) was multiplied by 1.414 to obtain an effective diameter of 17.32 inches (0.44 meters).

Table 7-3: GEP Stack Height Analysis				
Building Description	**Height (ft)**	**Maximum Projected Width (ft)**	**"5L" Distance (ft)**	**Formula GEP Stack Height (ft)**
Main Generator Building (upper roof)	62.1	215.7	310.5	155.2
Main Generator Building (lower roof)	50.0	248.5	250.0	125.0

Table 7-4: Comparison of U.S. EPA and U.S. NRC Meteorological Monitoring System Equipment Specifications

Parameter	Measure	U.S. EPA Monitoring Guideline	U.S. NRC RG1.23 and ANSI 2.5
Wind Speed	Accuracy	plus/minus 0.2 m/s + 5% of value	plus/minus 0.22 m/s for < 5 mph; 10% above 5 mph
	Starting Threshold	0.5 m/s	0.45 m/s
Wind Direction	Accuracy	plus/minus 5 degrees	plus/minus 5 degrees
	Starting Threshold	0.5 m/s	0.45 m/s
	Damping Ratio	0.4-0.7	0.4-0.6
	Delay Distance @ 10 degrees	5 m	2 m
Temperature	Accuracy	plus/minus 0.5 degrees C	plus/minus 0.5 degrees C
Delta-T	Accuracy	plus/minus 0.1 degrees C	plus/minus 0.15 degrees C/50 m
Data Recovery	Joint Recovery of Wind Direction and Speed and Delta-T	90%	90%

Table 7-5: Sensitive Population Receptors					
Location	**UTM Easting (m)**	**UTM Northing (m)**	**Elevation (m)**	**Distance[a] (km)**	**Direction[a] (degrees)**
Buchanan-Verplanck ES	588,254	4,567,885	3.96	1.0	124
Frank G. Lindsey ES	588,988	4,567,139	32.61	2.0	130
Hendrick Hudson HS	589,200	4,567,307	36.58	2.1	123
Woodside ES	590,146	4,570,403	52.43	3.3	54
Peekskill MS	590,069	4,570,875	56.39	3.6	47
Assumption ES	590,354	4,571,210	46.33	4.0	46
Peekskill HS	590,668	4,570,867	79.55	4.0	53
McKinley School	589,430	4,569,263	21.64	2.1	67
Franklin School	589,735	4,570,197	43.89	2.9	52
St. Joseph's School	589,454	4,570,453	27.43	2.8	44
Drum Hill School	590,115	4,571,075	54.25	3.8	45
St. Mary's School	589,427	4,571,075	83.21	3.3	37
Keon School	590,234	4,566,192	31.09	3.6	129
International Pre-School Center	588,791	4,568,099	11.89	1.4	103
Hansel & Gretel Nursery School	589,755	4,569,731	39.93	2.6	60
St. Patrick's Pre-K	587,077	4,567,584	19.20	0.9	205
Sunset Nursery School	588,559	4,566,314	31.70	2.4	152
Mt. Airy Nursery School	589,599	4,566,915	32.92	2.6	125
Peekskill Headstart/Daycare Center	590,075	4,571,190	41.15	3.8	43
Aunt Bessie's Open Door Day Care Center	590,369	4,571,139	48.46	4.0	47
Montrose Childcare Center	589,474	4,565,281	31.70	3.7	147
Community-Based Services	588,769	4,567,657	28.35	1.5	120
Mt. St. Francis Convent & Franciscan Sisters Infirmary	590,019	4,571,234	29.57	3.8	42
Community Aid for Retarded Children	589,554	4,571,259	11.58	3.5	36
VA Hudson Valley Health Care System	589,735	4,565,429	39.01	3.8	143
House of Prayer Church	587,040	4,570,456	3.05	2.1	348
St. John's Church	585,236	4,568,129	58.22	2.2	263
Buchanan Village Hall	588,470	4,568,090	7.01	1.1	108
St. Christopher's Church	589,174	4,567,476	36.58	2.0	119
Assumption Church	589,985	4,570,749	49.07	3.4	47

[a]Distance and direction from the proposed Facility (located at 587,460 meters UTM Easting, 4,568,417 meters UTM Northing).

Table 7-6: Turbine Load Analysis Maximum Modeled Concentrations						
Pollutant	Averaging Period	Significant Impact Concentration (µg/m^3)	Maximum Modeled Concentration (µg/m^3)	Maximum Modeled Concentration Location		
				UTM East (m)	UTM North (m)	Elevation (m)
CO	1-Hour	2,000	10.6[a]	584,932	4,570,538	303.7
	8-Hour	500	5.1[a]	584,932	4,570,538	303.7
SO_2	3-Hour	25	2.6[a]	584,932	4,570,538	303.7
	24-Hour	5	0.4[a]	584,932	4,570,538	303.7
	Annual	1	0.01[b]	586,537	4,570,954	210.4
PM-10	24-Hour	5	4.1[c]	585,238	4,570,281	272.5
	Annual	1	0.2[c]	586,537	4,570,954	210.4
NO_2	Annual	1	0.1[d]	586,537	4,570,954	210.4

[a]Maximum modeled concentration results from operating case 1.
[b]Maximum modeled concentration results from operating case 2.
[c]Maximum modeled concentration results from operating case10.
[d]Maximum modeled concentration results from operating case 3.

Table 7-7: Overall Facility Maximum Modeled Concentrations									
Pollutant	Averaging Period	Significant Impact Concentration (ug/m^3)	NAAQS (ug/m^3)	Year of Maximum Modeled Concentration	Maximum Modeled Concentration[a] (ug/m^3)	Maximum Modeled Concentration Location		Distance[b] (m)	Direction[b] (degrees)
						UTM East (m)	UTM North (m)		
CO	1-hour	2,000	40,000	2000	10.9	584,932	4,570,538	3,300	310
	8-hour	500	10,000	1996	5.2	584,932	4,570,538	3,300	310
SO_2	3-hour	25	1,300	1996	2.6	584,932	4,570,538	3,300	310
	24-hour	5	365	1996	0.4	584,932	4,570,538	3,300	310
	Annual	1	80	1998	0.02	586,537	4,570,954	2,700	340
PM-10	24-hour	5	150	1996	4.2	586,110	4,570,755	2,700	330
	Annual	1	50	1998	0.2	586,537	4,570,954	2,700	340
NO_2	Annual	1	100	1998	0.4	587,417	4,568,270	153	196

[a]Result of modeling the worst case turbine operating scenario along with the fuel gas heater using ISCST3.

[b]Distance and direction from the proposed Facility (located at 587,460 meters UTM Easting, 4,568,417 meters UTM Northing).

Table 7-8: Sensitive Population Receptors' Maximum Modeled Concentrations (ug/m^3)								
LOCATION	CO		SO_2			PM-10		NO_2
	NAAQS 40,000 ug/m^3	NAAQS 10,000 ug/m^3	NAAQS 1,300 ug/m^3	NAAQS 365 ug/m^3	NAAQS 80 ug/m^3	NAAQS 150 ug/m^3	NAAQS 50 ug/m^3	NAAQS 100 ug/m^3
	1-Hour	8-Hour	3-Hour	24-Hour	Annual	24-Hour	Annual	Annual
Buchanan-Verplanck ES	1.5	0.3	0.02	0.005	0.0004	0.04	0.003	0.034
Frank G. Lindsey ES	0.7	0.2	0.10	0.027	0.0009	0.27	0.011	0.035
Hendrick Hudson HS	0.9	0.2	0.11	0.029	0.0008	0.25	0.010	0.030
Woodside ES	1.4	0.3	0.06	0.018	0.0004	0.14	0.005	0.010
Peekskill MS	1.3	0.4	0.06	0.020	0.0004	0.16	0.004	0.010
Assumption ES	1.0	0.3	0.06	0.018	0.0003	0.15	0.004	0.008
Peekskill HS	1.7	0.3	0.08	0.025	0.0006	0.18	0.007	0.016
McKinley School	0.8	0.2	0.08	0.020	0.0006	0.22	0.007	0.012
Franklin School	1.1	0.2	0.07	0.021	0.0004	0.17	0.005	0.011
St. Joseph's School	0.5	0.1	0.07	0.022	0.0004	0.19	0.004	0.009
Drum Hill School	1.3	0.3	0.06	0.019	0.0004	0.16	0.004	0.010
St. Mary's School	1.9	0.5	0.08	0.027	0.0008	0.21	0.008	0.024
Keon School	0.6	0.1	0.06	0.017	0.0007	0.16	0.009	0.021
International Pre-School Center	0.5	0.2	0.07	0.018	0.0006	0.23	0.008	0.022
Hansel & Gretel Nursery School	0.9	0.3	0.06	0.017	0.0005	0.17	0.006	0.011
St. Patrick's Pre-K	1.8	0.5	0.03	0.014	0.0015	0.07	0.008	0.112
Sunset Nursery School	0.9	0.2	0.09	0.024	0.0009	0.25	0.011	0.026
Mt. Airy Nursery School	0.7	0.2	0.08	0.023	0.0008	0.21	0.009	0.025
Peekskill Headstart/Daycare Center	0.8	0.2	0.06	0.019	0.0003	0.15	0.004	0.009
Aunt Bessie's Open Door Day Care Center	0.9	0.2	0.06	0.018	0.0004	0.15	0.004	0.008
Montrose Childcare Center	0.6	0.1	0.06	0.016	0.0007	0.15	0.009	0.018
Community-Based Services	1.2	0.2	0.11	0.024	0.0008	0.25	0.010	0.032

Table 7-8: Sensitive Population Receptors' Maximum Modeled Concentrations (ug/m³)									
LOCATION	CO		SO_2			PM-10		NO_2
	NAAQS 40,000 ug/m³	NAAQS 10,000 ug/m³	NAAQS 1,300 ug/m³	NAAQS 365 ug/m³	NAAQS 80 ug/m³	NAAQS 150 ug/m³	NAAQS 50 ug/m³	NAAQS 100 ug/m³
	1-Hour	8-Hour	3-Hour	24-Hour	Annual	24-Hour	Annual	Annual
Mt. St. Francis Convent & Franciscan Sisters Infirmary	0.6	0.1	0.06	0.019	0.0003	0.15	0.004	0.008
Community Aid for Retarded Children	0.7	0.1	0.05	0.017	0.0003	0.14	0.003	0.007
VA Hudson Valley Health Care System	0.7	0.2	0.05	0.012	0.0008	0.14	0.009	0.020
House of Prayer Church	0.8	0.2	0.08	0.015	0.0009	0.17	0.008	0.048
St. John's Church	1.7	0.3	0.04	0.008	0.0003	0.06	0.002	0.014
Buchanan Village Hall	0.8	0.2	0.01	0.004	0.0003	0.09	0.003	0.023
St. Christopher's Church	0.8	0.2	0.11	0.031	0.0008	0.26	0.010	0.028
Assumption Church	1.0	0.2	0.06	0.020	0.0004	0.16	0.004	0.010

APPENDIX A

NYSDEC PERMIT APPLICATION FORMS

New York State Department of Environmental Conservation
Air Permit Application

DEC ID	APPLICATION ID	OFFICE USE ONLY
- -	- -	

Section I - Certification

Title V Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based upon my inquiry of the person or persons directly responsible for gathering information [required pursuant to 6 NYCRR 201-6.3(d)] I believe the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations.

Responsible Official	Michael R. Kansler	Title	Senior Vice President & COO
Signature	[signature]	Date	6/20/02

State Facility Certification

I certify that this facility will be operated in conformance with all provisions of existing regulations.

Responsible Official		Title	
Signature		Date	

Section II - Identification Information

Title V Facility Permit			State Facility Permit	
☒ New	☐ Significant Modification	☐ Administrative Amendment	☐ New	☐ Modification
☐ Renewal	☐ Minor Modification	General Permit Title:	General Permit Title:	
☒ Application involves construction of new facility			☐ Application involves construction of new emission unit(s)	

Owner/Firm

Name	Entergy Indian Point Peaking Facility, LLC						
Street Address	440 Hamilton Avenue						
City	White Plains	State	NY	Country	USA	Zip	10601
Owner Classification	☐ - Federal ☒ - Corporation/Partnership		☐ - State ☐ - Individual		☐ - Municipal	Taxpayer ID	020618444

Facility

☐ - Confidential

Name	Indian Point Peaking Facility		
Street Address	295 Broadway, Suite 3		
☐ City / ☐ Town / ☒ Village	Buchanan	Zip	10511-0308

Project Description

☐ - Continuation Sheet(s)

A new 330-megawatt (nominal) natural gas fired simple cycle electric power generation facility. The major components of the facility include two natural gas fired combustion turbines, two 11.8 mmBtu/hr natural gas fired fuel heaters, SCR and oxidation catalyst controls, three exhaust stacks, and a 15,000 gallon aqueous ammonia (19%) storage tank. Distillate fuel oil will not be used at the facility; Applicable LAER requirements are more restrictive than NOx RACT.

Owner/Firm Contact Mailing Address

Name (Last, First, Middle Initial)	Kansler, Michael R.					Phone No.	(914) 272-3200
Affiliation	Entergy Indian Point Peaking Facility, LLC	Title	Sr. VP & COO			Fax No.	(914) 272-3205
Street Address	440 Hamilton Avenue						
City	White Plains	State	NY	Country	USA	Zip	10601

Facility Contact Mailing Address

Name (Last, First, Middle Initial)	Kansler, Michael R.					Phone No.	(914) 272-3200
Affiliation	Entergy Indian Point Peaking Facility, LLC	Title	Sr. VP & COO			Fax No.	(914) 272-3205
Street Address	440 Hamilton Avenue						
City	White Plains	State	NY	Country	USA	Zip	10601

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Section III - Facility Information

Classification

☐ Hospital ☐ Residential ☐ Educational/Institutional ☐ Commercial ☐ Industrial ☒ Utility

Affected States (Title V)

☐ Vermont ☐ Massachusetts ☐ Rhode Island ☒ Pennsylvania Tribal Land:

☐ New Hampshire ☒ Connecticut ☒ New Jersey ☐ Ohio Tribal Land:

SIC Codes

☐ Continuation Sheet(s)

4911											

Facility Description

☐ Continuation Sheet(s)

The facility will consist of two GE 7FA combustion turbines, each rated at 1,979 mmBtu/hr at -10 deg F and equipped with dry low-NOx combustors, SCR and oxidation catalyst controls, two natural gas fired fuel gas heaters, and a 15,000-gallon aqueous (19%) ammonia storage tank. The turbines and heaters will be fueled exclusively with natural gas.

Compliance Statements (Title V Only)

I certify that as of the date of this application the facility is in compliance with all applicable requirements: ☐ YES ☐ NO **N/A - New Facility**

If one of more emission units at the facility are not in compliance with all applicable requirements at the time of signing this application (the 'NO' box must be checked), the noncomplying units must be identified in the "Compliance Plan" block on Page 8 of this form along with the compliance plan information required. For all emission sources at this facility that are operating in compliance with all applicable requirements complete the following:

- ☐ This facility will continue to be operated and maintained in such a manner as to assure compliance for the duration of the permit, except those units referenced in the compliance plan portion of Section IV of this application.
- ☐ For all emission units, subject to any applicable requirements that will become effective during the term of the permit, this facility will meet all such requirements on a timely basis.
- ☐ Compliance certification reports will be submitted at least once per year. Each report will certify compliance status with respect to each requirement, and the method used to determine the status.

Facility Applicable Federal Requirements

☒ Continuation Sheet(s)

Title	Type	Part	Subpart	Section	Subdivision	Paragraph	Sub Paragraph	Clause	Subclause
6	NYCRR	200	5						
6	NYCRR	200	6						
6	NYCRR	200	7						
6	NYCRR	201	1	4					
6	NYCRR	201	1	5					

Facility State Only Requirements

☐ Continuation Sheet(s)

Title	Type	Part	Subpart	Section	Subdivision	Paragraph	Sub Paragraph	Clause	Subclause
6	NYCRR	207							
6	NYCRR	211	2						
6	NYCRR	221							

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Section III - Facility Information

Facility Applicable Federal Requirements (continuation)

Title	Type	Part	Subpart	Section	Subdivision	Paragraph	Sub Paragraph	Clause	Subclause
6	NYCRR	201	1	2					
6	NYCRR	201	1	6					
6	NYCRR	201	1	7					
6	NYCRR	201	1	8					
6	NYCRR	201	1	10	a				
6	NYCRR	201	3	2	a				
6	NYCRR	201	3	3	a				
6	NYCRR	201	6	1	a	1			
6	NYCRR	201	6	1	b				
6	NYCRR	201	6	3					
6	NYCRR	201	6	4					
6	NYCRR	201	6	5					
6	NYCRR	201	6	6	b				
6	NYCRR	201	6	6	c				
6	NYCRR	202	1	1					
6	NYCRR	202	1	2					
6	NYCRR	202	1	5					
6	NYCRR	202	2						
6	NYCRR	204							
6	NYCRR	211	3						
6	NYCRR	215							
6	NYCRR	227	1	3					
6	NYCRR	227	2						
6	NYCRR	231	2	2	a	1			
6	NYCRR	231	2	2	a	2			
6	NYCRR	231	2	3					
6	NYCRR	231	2	4					
6	NYCRR	231	2	5					
6	NYCRR	231	2	6					
6	NYCRR	231	2	9					
6	NYCRR	231	2	10					
6	NYCRR	231	2	12					
6	NYCRR	621		13		a			
6	NYCRR	621		14					
6	NYCRR	621		5		a			
40	CFR	60	A						
40	CFR	72	A	6	a	3			
40	CFR	72	A	9					

DEC ID
- -

Section III - Facility Information (continued)

Facility Compliance Certification

☒ Continuation Sheet(s)

Rule Citation

Title	Type	Part	Subpart	Section	Subdivision	Paragraph	Sub Paragraph	Clause	Subclause
6	NYCRR	211	3						

	Capping	CAS No.	Contaminant Name
☒ Applicable Federal Requirement	☐ Capping		
☐ State Only Requirement			

Monitoring Information

☐ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ☐ RecordKeeping/Maintenance Procedures

Description

No person shall cause or allow any air contamination source to emit any material having an opacity equal to or greater than 20 percent (six minute average) except for one continuous six-minute period per hour of not more than 57 percent opacity. Compliance with this opacity requirement will be shown in accordance with 40 CFR 60, Method 9.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR 60, Method 9

Parameter Code	Parameter Description	Manufacturer Name/Model No.
01	Opacity	

Limit Upper	Limit Lower	Limits Units Code	Limits Units Description
20		136	Percent

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
18	6-minute Average (Method 9)	13	Single Occurrence	10	Upon Request

Facility Emissions Summary

☒ Continuation Sheet(s)

CAS No.	Contaminant Name	PTE (lbs/yr)	PTE Range Code	Actual (lbs/yr)
NY075 - 00 - 5	PM-10		G	
NY075 - 00 - 0	Particulates		G	
7446 - 09 - 5	SO2		C	
NY210 - 00 - 0	NOx		G	
630 - 08 - 0	CO		F	
NY998 - 00 - 0	VOC		C	
NY100 - 00 - 0	HAP		B	
07664 - 93 - 9	Sulfuric Acid		D	
07664 - 41 - 7	Ammonia		G	

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Facility Emissions Summary (Continued)

CAS No.	Contaminant Name	PTE (lbs/yr)	PTE Range Code	Actual (lbs/yr)
106 - 99 - 0	1,3 -- Butadiene		Y	
83 - 32 - 9	Acenaphthene		Y	
208 - 96 - 8	Acenaphthylene		Y	
75 - 07 - 0	Acetaldehyde		Y	
120 - 12 - 7	Anthracene		Y	
7440 - 38 - 2	Arsenic		Y	
56 - 55 - 3	Benz(a)anthracene		Y	
71 - 43 - 2	Benzene		Y	
50 - 32 - 8	Benzo(a)pyrene		Y	
205 - 99 - 2	Benzo(b)fluoranthene		Y	
191 - 24 - 2	Benzo(g,h,i)perylene		Y	
207 - 08- -9	Benzo(k)fluoranthene		Y	
107 - 02 - 8	Acrolein		Y	
218 - 01 - 9	Chrysene		Y	
53 - 70 - 3	Dibenz(a,h)anthracene		Y	
100 - 41 - 4	Ethylbenzene		Y	
206 - 44 - 0	Fluoranthene		Y	
7782 - 96 - 5	Fluorene		Y	
50 - 00 - 0	Formaldehyde		Y	
193 - 39 - 5	Indeno(1,2,3-cd)pyrene		Y	
91 - 20 - 3	Naphthalene		Y	
85 - 01 - 8	Phenanthrene		Y	
75 - 56 - 9	Propylene Oxide		Y	
129 - 00 - 0	Pyrene		Y	
108 - 88 - 3	Toluene		Y	
1330 - 20 - 7	Xylenes		Y	
- -				
- -				
- -				
- -				
- -				
- -				
- -				
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Section IV - Emission Unit Information

Emission Unit Description

☐ Continuation Sheet(s)

EMISSION UNIT	U0001

Emission Unit U0001 represents two identical GE 7FA combustion turbines rated at 1,979 mmBtu/hr (-10°F). The turbines burn natural gas only and are equipped with dry low-NOx combustors, SCR to control NOx emissions and catalytic oxidizers to control CO and VOC emissions. Each unit will vent to an individual 94-foot stack (EP001 & EP002). The turbines will generate approximately 165 MW of power each.

Building

☐ Continuation Sheet(s)

Building	Building Name	Length (ft)	Width (ft)	Orientation
BLDG01	Main Generator Building	180	210	

Emission Point

☐ Continuation Sheet(s)

EMISSION PT.	EP001					
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
119	94	32		950	372	216
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal
77.5	2,594,082	587.469	4568.453	BLDG01		
EMISSION PT.	EP002					
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
119	94	32		950	372	216
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal
77.5	2,594,082	587.497	4568.442	BLDG01		
EMISSION PT.						
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal

Emission Source/Control

☒ Continuation Sheet(s)

Emission Source ID	Type	Date Of Construction	Date Of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
CC001	C	May 2003	June 2004				GE 7FA Combustion Turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
1,979	201	mmBtu/hr				

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Section IV - Emission Unit Information

EMISSION UNIT	
U0001	Emission Source/Control (continuation)

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
DLN01	K	May 2003	June 2004		103	Dry Low NO_x Combustor	GE 7FA Combustion Turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
SCR01	K	May 2003	June 2004		033	SCR	Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
OXY01	K	May 2003	June 2004		065	Catalytic Reduction	Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
CC002	C	May 2003	June 2004				GE 7FA Combustion Turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
1,979	201	mmBtu/hr				

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
DLN02	K	May 2003	June 2004		103	Dry Low NO_x Combustor	GE 7FA Combustion Turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
SCR02	K	May 2003	June 2004		033	SCR	Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
OXY02	K	May 2003	June 2004		065	Catalytic Reduction	Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

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Section IV - Emission Unit Information

Emission Unit Description

☐ Continuation Sheet(s)

EMISSION UNIT	U0002

Emission Unit U0002 represents two identical natural gas-fired, natural gas fuel heaters each rated at 11.8 mmBtu/hr.
Only one fuel gas heater will run at a time. Each unit will share a 94-foot stack (EP003).

Building

☐ Continuation Sheet(s)

Building	Building Name	Length (ft)	Width (ft)	Orientation
BLDG01	Main Generator Building	180	210	

Emission Point

☐ Continuation Sheet(s)

EMISSION PT.	EP003					
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (^oF)	Cross Section Length (in)	Cross Section Width (in)
119	94	32	12.3	805		
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal
58	413,504	587.469	4568.453	BLDG01		

EMISSION PT.						
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (^oF)	Cross Section Length (in)	Cross Section Width (in)
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal

EMISSION PT.						
Ground Elev. (ft.)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (^oF)	Cross Section Length (in)	Cross Section Width (in)
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal

Emission Source/Control

☒ Continuation Sheet(s)

Emission Source ID	Type	Date Of Construction	Date Of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
FH001	C	May 2003	June 2004				Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
11.8	201	mmBtu/hr				

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Section IV - Emission Unit Information

EMISSION UNIT	Emission Source/Control (continuation)
U0002	

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.
FH002	C	May 2003	June 2004				Unknown

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
11.8	201	mmBtu/hr				

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

Emission Source ID	Emission Source Type	Date of Construction	Date of Operation	Date of Removal	Control Type Code	Control Type Description	Manufacturer's Name/Model No.

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description

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Section IV - Emission Unit Information (continued)

Process Information

☐ Continuation Sheet(s)

EMISSION UNIT	U0001	PROCESS	P01

Description

Emission Unit U0001 represents two natural gas-fired GE 7FA combustion turbines, each rated at 1,804 mmBtu/hr during average ambient conditions (50°F) and 1,979 mmBtu/hr maximum (at -10°F). Process P01 represents natural gas operation of the combustion turbine. The turbines will only fire natural gas. Dry low-NOx combustion technology and Selective Catalytic Reduction (SCR) will be employed for control of NOx emissions. Catalytic oxidation will be used to control CO and VOC emissions. The total throughput limits specified below represent the maximum fuel usage, on an hourly and annual basis, and are for both turbines. The Higher Heating Value (HHV) of 1,020 Btu/cubic foot is represented for natural gas.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-002-01	3.880	33,989	0115	million cubic feet gas

☐ Confidential
☒ Operating at Maximum Capacity
☐ Activity with Insignificant Emissions

Operating Schedule		Building	Floor/Location
Hrs/Day	Days/Yr		
24	365	BLDG01	Ground

Emission Source/Control Identifier(s) (continued)

CC001	DLN01	SCR01	OXY01	CC002	DLN02	SCR02	OXY02

EMISSION UNIT	U0002	PROCESS	P02

Description

Emission Unit U0002 represents two natural gas-fired fuel gas heaters, each rated at 11.8 mmBtu/hr. Process P02 represents natural gas firing of the heaters. Only one fuel gas heater is to be used at any one time, the other unit will serve as a back-up. These units are included in the permit (i.e., not exempt) since NOx emissions are subject to LAER limits. Quantity per hour throughput listed below represents full load firing (11.8 mmBtu/hr) of one heater on natural gas. The annual throughput is based on the use of one heater for a full year, at full load. Fuel quantities are based on a natural gas Higher Heating Value (HHV) of 1,020 Btu/cubic foot. The heaters can only fire natural gas.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
	11.57	101,341	598	1,000 cubic feet

☐ Confidential
☒ Operating at Maximum Capacity
☐ Activity with Insignificant Emissions

Operating Schedule		Building	Floor/Location
Hrs/Day	Days/Yr		
24	365	BLDG01	Ground

Emission Source/Control Identifier(s) (continued)

FH001	FH002						

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Section IV - Emission Unit Information (continued)

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements ☒ Continuation Sheet(s)									
				Title	Type	Part	SubPart	Section	SubDivision	Parag.	Sub Parag.	Clause	SubClause
U0001				40	CFR	60	A	7					
U0001				40	CFR	60	A	8					
U0001				40	CFR	60	A	11					
U0001				40	CFR	60	A	12					
U0001				40	CFR	60	A	13					

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements ☐ Continuation Sheet(s)									
				Title	Type	Part	SubPart	Section	SubDivision	Parag.	Sub Parag.	Clause	SubClause

Emission Unit Compliance Certification

☒ Continuation Sheet(s)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	231	2	5					

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0002		P02		NY210 - 00 - 0	Oxides of Nitrogen

Monitoring Information

☐ Continuous Emission Monitoring
☒ Intermittent Emission Testing
☐ Ambient Air Monitoring
☐ Monitoring of Process or Control Device Parameters as Surrogate
☐ Work Practice Involving Specific Operations
☐ Record Keeping/Maintenance Procedures

Description

0.11 lb/mmBtu NOx emission limit for the fuel gas heater based upon Higher Heating Value (HHV) of fuel. This emission limit applies at all loads except during startup and shutdown. The facility will demonstrate compliance with this emission limit via stack testing.

Work Practice Type	Parameter Code	Parameter Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 19

Parameter Code	Parameter Description	Manufacturer Name/Model No.
NY210 - 00 - 0	Oxides of Nitrogen	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.11		7	pounds per million Btus

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
08	1-Hour Average	14	As Required	10	Upon Request

DEC ID

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Section IV - Emission Unit Information (continued)

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements							☐ Continuation Sheet(s)		
				Title	Type	Part	SubPart	Section	SubDivision	Parag.	Sub Parag.	Clause	SubClause
U0001				40	CFR	60	A	19					
U0001				40	CFR	60	GG	332	a	1			
U0001				40	CFR	60	GG	333	b				
U0001				40	CFR	60	GG	334	b				
U0001				40	CFR	60	GG	335	c				
U0001				40	CFR	60	GG	335	d				
U0001				40	CFR	60	GG	335	e				
U0001				40	CFR	72	A	9					
U0001				40	CFR	75	A	5					
U0001				40	CFR	75	B	10					
U0001				40	CFR	75	B	11	d				
U0001				40	CFR	75	B	11	d	2			
U0001				40	CFR	75	B	12	a				
U0001				40	CFR	75	B	12	b				
U0001				40	CFR	75	B	13	b				
U0001				40	CFR	75	C						
U0001				40	CFR	75	D						
U0001				40	CFR	75	F	53	a				
U0001				40	CFR	75	F	53	b				
U0001				40	CFR	75	F	53	e				
U0001				40	CFR	75	F	53	f				
U0001				40	CFR	75	F	54					
U0001				40	CFR	75	F	58	b	2			
U0001				40	CFR	75	F	58	b	3			
U0001				40	CFR	75	F	58	c				
U0001				40	CFR	75	F	59					
U0001				40	CFR	75	G						
U0001				6	NYCRR	227	1	3	b	1			
U0001				6	NYCRR	227	2	1	a	5			
U0001				6	NYCRR	227	2	2	b	10			
U0001				6	NYCRR	227	2	4	e	1	c		
U0001				6	NYCRR	227	2	6	a	5			
U0001				6	NYCRR	227	2	6	b				
U0001				6	NYCRR	227	2	6	c	2	ii		

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Emission Unit Compliance Certification (Continued)

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	1	3	a				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0001		P01			

Monitoring Information

☐ Continuous Emission Monitoring
☒ Intermittent Emission Testing
☐ Ambient Air Monitoring
☐ Monitoring of Process or Control Device Parameters as Surrogate
☐ Work Practice Involving Specific Operations
☐ Record Keeping/Maintenance Procedures

Description

No person shall operate a stationary combustion installation which exhibits greater than 20 percent opacity (six minute average), except for one six-minute period per hour of not more than 27 percent opacity.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR 60 Appendix A Method 9

Parameter Code	Parameter Description	Manufacturer Name/Model No.
01	Opacity	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
20		136	Percent Opacity

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
18	6-minute Average	14	As required	10	Upon Request

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	231	2	5					

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0001		P01		NY210 - 00 - 0	Oxides of Nitrogen

Monitoring Information

☒ Continuous Emission Monitoring
☐ Intermittent Emission Testing
☐ Ambient Air Monitoring
☐ Monitoring of Process or Control Device Parameters as Surrogate
☐ Work Practice Involving Specific Operations
☐ Record Keeping/Maintenance Procedures

Description

4.0 ppmvd (corrected to 15% O_2) NO_x emission limit from the combustion turbine based upon Higher Heating Value (HHV) of fuel. This emission limit applies at all loads except during startup and shutdown.
The proposed facility will use a CEM to monitor NO_x stack emissions from Unit U0001.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 19

Parameter Code	Parameter Description	Manufacturer Name/Model No.
23	Concentration	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
4.0		275	Parts per million by volume (dry, corrected to 15% O2)

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
08	1-Hour Average	01	Continuous	07	Quarterly

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Emission Unit Compliance Certification (Continued)

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	1	3	a				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0002		P02			

Monitoring Information

- ☐ Continuous Emission Monitoring
- ☒ Intermittent Emission Testing
- ☐ Ambient Air Monitoring
- ☐ Monitoring of Process or Control Device Parameters as Surrogate
- ☐ Work Practice Involving Specific Operations
- ☐ Record Keeping/Maintenance Procedures

Description

No person shall operate a stationary combustion installation which exhibits greater than 20 percent opacity (six minute average), except for one six-minute period per hour of not more than 27 percent opacity.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR 60 Appendix A Method 9

Parameter Code	Parameter Description	Manufacturer Name/Model No.
01	**Opacity**	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
20		136	**Percent Opacity**

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
18	**6-minute Average**	14	**As required**	10	**Upon Request**

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	231	2						

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0002		P02			

Monitoring Information

- ☐ Continuous Emission Monitoring
- ☐ Intermittent Emission Testing
- ☐ Ambient Air Monitoring
- ☒ Monitoring of Process or Control Device Parameters as Surrogate
- ☐ Work Practice Involving Specific Operations
- ☐ Record Keeping/Maintenance Procedures

Description

Operations of Emission Unit U0002 will be such that only one of the two natural gas-fired natural gas fuel heaters will be in operation at any one time. Fuel use will be tracked to demonstrate a maximum 101,341,177 cubic feet of natural gas being fired by the gas heaters (11.8 mmBtu/hr * 8,760 hrs/yr divided by 1,020 Btu/cubic foot) to ensure facility VOC PTE is at or below 20.1 tons per year.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	**Natural Gas**	

Parameter Code	Parameter Description	Manufacturer Name/Model No.
NY998 - 00- 0	**Volatile Organic Compounds**	**Fuel Flow Meter (Type Unknown)**

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
101,341,177		43	**Cubic Feet per Year**

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
17	**Annual Maximum Rolled Monthly**	01	**Continuous**	09	**Annually**

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Emission Unit Compliance Certification (Continued)

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	231	2	5					

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0001		P01		NY998 - 00 - 0	Volatile Organic Compounds

Monitoring Information

☐ Continuous Emission Monitoring
☒ Intermittent Emission Testing
☐ Ambient Air Monitoring
☐ Monitoring of Process or Control Device Parameters as Surrogate
☐ Work Practice Involving Specific Operations
☐ Record Keeping/Maintenance Procedures

Description

0.0014 lb/mmBtu VOC limit from each combustion turbine based on the Higher Heating Value (HHV) of fuel. This emission limit applies at all loads except start-up and shutdown. The proposed facility will demonstrate compliance via stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR 60 Appendix A Method 25

Parameter Code	Parameter Description	Manufacturer Name/Model No.
NY998 - 00 - 0	Volatile Organic Compounds	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0014		7	Pounds per Million Btus

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
08	1-Hour Average	14	As Required	10	Upon Request

Applicable Rule

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	60	48c						

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS. No.	Contaminant Name
U0002		P02			

Monitoring Information

☐ Continuous Emission Monitoring
☐ Intermittent Emission Testing
☐ Ambient Air Monitoring
☐ Monitoring of Process or Control Device Parameters as Surrogate
☐ Work Practice Involving Specific Operations
☒ Record Keeping/Maintenance Procedures

Description

The fuel gas heaters are subject to 40 CFR 60 Subpart Dc based on the definition of steam generating unit and their maximum firing rate. Because the heaters only burn natural gas, the only applicable requirements are the recordkeeping and reporting requirements outlined in 60.48c

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method

Parameter Code	Parameter Description	Manufacturer Name/Model No.

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
				10	Upon Request

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Section IV - Emission Unit Information (continued)

Determination of Non-Applicability (Title V Only)

☐Continuation Sheet(s)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	75	11	e					

Emission Unit	Emission Point	Process	Emission Source		
U0001					☐Applicable Federal Requirement ☐State Only Requirement

Description

Since the combustion turbines are limited to natural gas firing only, continuous emission monitoring of SO_2 is not required. An alternative monitoring method including fuel flow and fuel sulfur content will be developed for agency approval.

Rule Citation

Title	Type	Part	SubPart	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause

Emission Unit	Emission Point	Process	Emission Source		
					☐Applicable Federal Requirements ☐State Only Requirement

Description

Process Emissions Summary

☐ Continuation Sheet(s)

Emission Unit						PROCESS	
CAS No.	Contaminant Name	% Thruput	% Capture	% Control		ERP (LB/HR)	ERP How Determined

PTE (lb/hr)	PTE (lb/yr)	PTE (standard units)	Standard Units	PTE How Determined	Actual (lb/hr)	Actual (lb/yr)

Emission Unit						PROCESS	
CAS No.	Contaminant Name	% Thruput	% Capture	% Control		ERP (LB/HR)	ERP How Determined

PTE (lb/hr)	PTE (lb/yr)	PTE (standard units)	Standard Units	PTE How Determined	Actual (lb/hr)	Actual (lb/yr)

Emission Unit						PROCESS	
CAS No.	Contaminant Name	% Thruput	% Capture	% Control		ERP (LB/HR)	ERP How Determined

PTE (lb/hr)	PTE (lb/yr)	PTE (standard units)	Standard Units	PTE How Determined	Actual (lb/hr)	Actual (lb/yr)

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Section IV - Emission Unit Information (continued)

Emission Unit	Emission Unit Emission Summary ☐ Continuation Sheet(s)			
CAS No.	Contaminant Name			
ERP (lb/yr)	PTE Emissions		Actual	
	(lb/hr)	(lb/yr)	(lb/hr)	(lb/yr)
CAS No.	Contaminant Name			
ERP (lb/yr)	PTE Emissions		Actual	
	(lb/hr)	(lb/yr)	(lb/hr)	(lb/yr)
CAS No.	Contaminant Name			
ERP (lb/yr)	PTE Emissions		Actual	
	(lb/hr)	(lb/yr)	(lb/hr)	(lb/yr)
CAS No.	Contaminant Name			
ERP (lb/yr)	PTE Emissions		Actual	
	(lb/hr)	(lb/yr)	(lb/hr)	(lb/yr)

Compliance Plan

☐ Continuation Sheet(s)

For any emission units which are not in compliance at the time of permit issuance, the applicant shall complete the following:

Consent Order

Certified progress reports are to be submitted every 6 months beginning ___/___/___

Emission Unit	Process	Emission Source	Applicable Federal Requirements									
			Title	Type	Part	Sub Part	Section	Sub Division	Parag.	SubParag.	Clause	SubClause

Remedial Measure/Intermediate Milestones	R/I	Date Schedules

DEC ID

	-					-					

Supporting Documentation

- ☐ P.E. Certification (form attached)
- ☐ List of Exempt Activities (form attached) **NA - No Exempt Activities**
- ☒ Plot Plan*
- ☒ Methods Used to Determine Compliance (form attached)
- ☒ Calculations*
- ☐ Air Quality Model (___ / ___ / ___)
- ☐ Confidentiality Justification
- ☐ Ambient Air Monitoring Plan (___ / ___ / ___)
- ☐ Stack Test Protocols/Reports (___ / ___ / ___)
- ☐ Continuous Emissions Monitoring Plans/QA/QC (___ / ___ / ___)
- ☐ MACT Demonstration (___ / ___ / ___)
- ☐ Operational Flexibility: Description of Alternative Operating Scenarios and Protocols
- ☒ Title IV: Application/Registration*
- ☐ ERC Quantification (form attached)
- ☐ Use of ERC(s) (form attached)
- ☐ Baseline Period Demonstration
- ☐ Analysis of Contemporaneous Emission Increase/Decrease
- ☒ LAER Demonstration* (___ / ___ / ___)
- ☐ BACT Demonstration* (___ / ___ / ___)
- ☐ Other Document(s): *** Contained in the Air Permit Application**

____
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New York State Department of Environmental Conservation
Air Permit Application

DEC ID
- -

METHODS USED TO DETERMINE COMPLIANCE

Emission Unit ID	Applicable Requirement	Method Used to Determine Compliance and Corresponding Date
Not Applicable – New Facility		

APPENDIX B

VENDOR DATA AND EMISSION CALCULATIONS

Table B-1
Indian Point Peaking Facility
Vendor Data

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	BASE	75%	50%	BASE	BASE	75%	50%
Inlet Loss	in H2O	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Pressure Loss	in H2O	11	6.7	4.5	9.2	5.9	4.1	7.6	7.2	5.1	3.6
Ambient Temperature	deg F	-10	-10	-10	50	50	50	100	100	100	100
Ambient Relative Humid.	%	60	60	60	60	60	60	60	60	60	60
Evap. Cooler Status		Off	Off	Off	Off	Off	Off	On	Off	Off	Off
Evap. Cooler Effectiveness	%							85			
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,008	21,008	21,008	21,008	21,008	21,008	21,008	21,008	21,008	21,008
Fuel Temperature	deg F	60	60	60	60	60	60	60	60	60	60
Output	kW	193,300	144,900	96,600	174,200	130,700	87,100	150,900	143,200	107,400	71,600
Heat Rate (LHV)	Btu/kWh	9,230	9,895	11,750	9,340	10,120	12,150	9,760	9,910	11,080	13,150
Heat Cons. (LHV)	MBtu/hr	1,784.2	1,433.8	1,135.1	1,627.0	1,322.7	1,058.3	1,472.8	1,419.1	1,190.0	941.5
CT Exhaust Flow x10^3	lb/hr	4046	3104	2515	3662	2907	2396	3282	3186	2668	2241
CT Exhaust Temperature	deg F	1042	1113	1164	1103	1152	1200	1152	1164	1196	1200
Exhaust Energy	MBtu/hr	1087.2	896	760.3	996.2	830.1	715	914.3	896.7	774.2	651

EMISSIONS

NOx	ppmvd @ 15% O2	9	9	9	9	9	9	9	9	9	9
NOx AS NO2	lb/hr	65	52	40	59	47	38	54	52	42	33
CO	ppmvd	9	9	9	9	9	9	9	9	9	9
CO	lb/hr	33	25	21	30	24	20	26	25	21	18
UHC	ppmvw	7	7	7	7	7	7	7	7	7	7
UHC	lb/hr	16	12	10	14	11	9	13	13	11	9
VOC	ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC	lb/hr	3.2	2.4	2	2.8	2.2	1.8	2.6	2.6	2.2	1.8
SO2	ppmvw	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
SO2	lb/hr	1.5	1.2	0.9	1.3	1.1	0.9	1.2	1.2	1	0.8
SO3	ppmvw	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
SO3	lb/hr	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Sulfur Mist	lb/hr	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Particulates (PM10 front half)	lb/hr	9	9	9	9	9	9	9	9	9	9
PM10 (front and back halves)	lb/hr	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.91	0.91	0.9	0.89	0.89	0.86	0.86	0.86	0.86
Nitrogen	75.24	75.13	75.22	74.7	74.67	74.78	72.06	72.35	72.39	72.56
Oxygen	12.88	12.58	12.85	12.7	12.62	12.92	12.01	12.14	12.27	12.77
Carbon Dioxide	3.73	3.87	3.75	3.75	3.79	3.65	3.74	3.72	3.66	3.43
Water	7.25	7.52	7.28	7.95	8.03	7.76	11.33	10.94	10.82	10.38

SITE CONDITIONS

Elevation	ft	120
Site Pressure	psia	14.64
Exhaust Loss	in H2O	9.0 @ ISO Conditions
Application		Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur emissions based on 0.0009 WT% Sulfur Content in the fuel.

IPS- Version Code - 3.1.3/49A0/2.3.0/PG7241UF-1200
SANDERJO 4/18/2002 15:50 Entergy - Indian Point7FAPartLoad.dat

Table B-2
Indian Point Peaking Facility
Potential Emissions Summary

Scenario			
CTG Load Ambient Temp, °F Natural Gas Operation (hr/yr)	100% 50 8,760	Fuel Gas Heater 8,760	**Total Facility** **PTE[(1)]** **tons/yr**
Potential to Emit (PTE), tons/yr	**One Unit**		
NO_x	112.15	5.69	**230.0**
CO	46.08	2.07	**94.2**
VOC	9.60	1.29	**20.5**
SO_2	11.07	0.072	**22.2**
H_2SO_4	12.71	0.0055	**25.4**
NH_3	103.61	--	**207.2**
PM-10	98.15	0.47	**196.8**

Notes:

(1) Annual emissions are based on an ambient temperature of 50 °F.

Table B-3
Indian Point Peaking Facility
Emissions Summary - GE 7FA Turbine

Scenario											
Ambient Temp (°F)		-10	-10	-10	50	50	50	100	100	100	100.0
% Load		BASE	75%	50%	BASE	75%	50%	BASE	BASE	75%	50%
Fuel Type		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Combustion Turbine (CTG) Heat Input (HHV) (mmBtu/hr)		1,979	1,590	1,259	1,804	1,467	1,174	1,633	1,574	1,320	1,044
Evaporative Cooler Status		Off	Off	Off	Off	Off	Off	On	Off	Off	Off
Evaporative Cooler Effectiveness								85%			
Exhaust Flow per Stack (lb/hr)		4,771,000	3,829,000	3,240,000	4,387,000	3,632,000	3,121,000	4,007,000	3,911,000	3,393,000	2,966,000
Uncontrolled CTG Pollutant Concentrations											
NO_x	ppmvd @ 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CO	ppmvd @ 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
VOC	ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC	ppmvd @ 15% O2	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.1	1.1	1.1
Uncontrolled CTG Pollutant Emission Rates, lb/hr											
NO_x	lb/hr	65.0	52.0	40.0	59.0	47.0	38.0	54.0	52.0	42.0	33.0
CO	lb/hr	33.0	25.0	21.0	30.0	24.0	20.0	26.0	25.0	21.0	18.0
VOC	lb/hr	3.2	2.4	2.0	2.8	2.2	1.8	2.6	2.6	2.2	1.8
PM/PM-10 (filterables and condensibles)	lb/hr	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Controlled Pollutant Concentrations											
NO_x (SCR control)	ppmvd @ 15% O2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO (oxidation catalyst)	ppmvd @ 15% O2	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
VOC (oxidation catalyst)	ppmvd @ 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0
Emission Factors, lb/mmBtu (HHV)											
NO_x	lb/mmBtu	0.0135	0.0137	0.0147	0.0142	0.0145	0.0156	0.0145	0.0148	0.0153	0.0163
CO	lb/mmBtu	0.0055	0.0056	0.0060	0.0058	0.0060	0.0064	0.0060	0.0061	0.0063	0.0067
VOC	lb/mmBtu	0.0012	0.0011	0.0013	0.0012	0.0012	0.0014	0.0012	0.0012	0.0013	0.0014
SO_2	lb/mmBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
Sulfuric Acid Mist (H_2SO_4)	lb/mmBtu	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
PM-10 (includes filterables, condensibles and sulfates)	lb/mmBtu	0.0115	0.0138	0.0169	0.0124	0.0148	0.0179	0.0135	0.0139	0.0162	0.0199
CTG Stack Emissions Estimates, lb/hr											
NO_x	lb/hr	26.63	21.76	18.47	25.60	21.26	18.33	23.69	23.33	20.14	17.05
CO	lb/hr	10.94	8.94	7.59	10.52	8.73	7.53	9.73	9.58	8.28	7.01
VOC	lb/hr	2.31	1.83	1.60	2.19	1.80	1.61	1.94	1.93	1.69	1.51
SO_2	lb/hr	2.77	2.23	1.76	2.53	2.05	1.64	2.29	2.20	1.85	1.46
SO_3	lb/hr	2.60	2.09	1.65	2.37	1.93	1.54	2.14	2.07	1.73	1.37
Sulfuric Acid Mist (H_2SO_4)	lb/hr	3.18	2.56	2.02	2.90	2.36	1.89	2.63	2.53	2.12	1.68
Ammonia Sulfates ($(NH_4)_2SO_4$)	lb/hr	4.29	3.44	2.73	3.91	3.18	2.54	3.54	3.41	2.86	2.26
PM-10 (filterables and condensibles)	lb/hr	18.50	18.50	18.50	18.50	18.50	18.50	18.50	18.50	18.50	18.50
PM-10 (includes filterables, condensibles and sulfates)	lb/hr	22.79	21.94	21.23	22.41	21.68	21.04	22.04	21.91	21.36	20.76
Ammonia (based on an ammonia slip of 10 ppmvd)	lb/hr	24.60	20.10	17.06	23.66	19.64	16.93	21.89	21.55	18.61	15.75

Notes:

1) Emissions of NH_3 after control by SCR are based on a 'slip' of 10 ppm: NH_3 (lb/hr) = Dry flue gas mole flow @ 15% O_2 (lb-mol/hr) * 10 (ppm) * 1/10^{6} (ppm) * 17 (lb/lb-mol)
2) The SCR is designed to reduce NO_x concentration to 4.0 ppmvd
3) The oxidation catalyst will reduce CO emissions by 70% and VOC emissions by 10%
4) Emissions of SO_2 are based upon a mass balance assuming all available elemental sulfur (MW=32) is converted to SO_2 (MW=64) during combustion.
Maximum natural gas sulfur content = 0.50 gr/100 SCF
5) Emissions of SO_3 are based on 75% conversion of SO_2 into SO_3.
6) Emissions of sulfuric acid mist from the turbine are based on the above SO_3 formation and assume 100% of SO_3 (MW=80) converts to H_2SO_4 (MW=98)
7) Emissions of ammonia salt from reaction of H_2SO_4 and NH_3 are calculated based on the above SO_3 formation and assume 100% of H_2SO_4 (MW=98) converts to sulfates (MW=132).
8) Heating value of combustion turbine fuels based upon the following annual average value for natural gas: 1,020 Btu/scf

Table B-4
Indian Point Peaking Facility
Turbine Emissions Modeling Parameters

CTG Load	BASE	75%	50%	BASE	75%	50%	BASE	BASE	75%	50%
Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Ambient Temp, °F	-10	-10	-10	50	50	50	100	100	100	100
Evaporative Cooler Status	Off	Off	Off	Off	Off	Off	On	Off	Off	Off
Evaporative Cooler Effectiveness							85%			
Stack Parameters										
Stack Diameter, m	8.12	8.12	8.12	8.12	8.12	8.12	8.12	8.12	8.12	8.12
Stack Diameter, ft	26.65	26.65	26.65	26.65	26.65	26.65	26.65	26.65	26.65	26.65
Exhaust Mass Flow, lb/hr	4,433,742	3,631,033	3,075,635	4,284,540	3,559,460	3,061,556	4,061,958	3,988,122	3,440,151	2,900,118
Exhaust Volumetric Flow, acfm	2,677,147	2,193,740	1,857,171	2,594,082	2,155,460	1,852,867	2,491,654	2,442,541	2,106,574	1,774,168
Stack Exit Velocity, ft/s	80.0	65.5	55.5	77.5	64.4	55.4	74.4	73.0	62.9	53.0
Stack Exit Velocity, m/s	24.4	20.0	16.9	23.6	19.6	16.9	22.7	22.2	19.2	16.2
Stack Exit Temperature, °F	950	950	950	950	950	950	950	950	950	950
Stack Exit Temperature, deg K	783.2	783.2	783.2	783.2	783.2	783.2	783.2	783.2	783.2	783.2
Flue Gas Analysis (%vol)										
Argon	0.91%	0.91%	0.91%	0.90%	0.89%	0.89%	0.86%	0.86%	0.86%	0.86%
Nitrogen	75.24%	75.13%	75.22%	74.70%	74.67%	74.78%	72.06%	72.35%	72.39%	72.56%
Oxygen	12.88%	12.58%	12.85%	12.70%	12.62%	12.92%	12.01%	12.14%	12.27%	12.77%
Carbon Dioxide	3.73%	3.87%	3.75%	3.75%	3.79%	3.65%	3.74%	3.72%	3.66%	3.43%
Water	7.25%	7.52%	7.28%	7.95%	8.03%	7.76%	11.33%	10.94%	10.82%	10.38%
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Molecular Weight	28.42	28.40	28.42	28.34	28.34	28.35	27.97	28.02	28.02	28.05
Final Exhaust Analysis (lbmol/hr)										
Argon	1,420	1,163	985	1,361	1,118	961	1,249	1,224	1,056	889
Nitrogen	117,385	96,048	81,410	112,926	93,794	80,746	104,634	102,984	88,868	75,021
Oxygen	20,095	16,083	13,907	19,199	15,852	13,951	17,439	17,280	15,063	13,203
Carbon Dioxide	5,819	4,948	4,059	5,669	4,761	3,941	5,431	5,295	4,493	3,546
Water	11,311	9,614	7,879	12,018	10,087	8,379	16,452	15,572	13,283	10,732
TOTAL	156,029	127,855	108,239	151,173	125,612	107,978	145,204	142,356	122,763	103,392
TOTAL (dry)	144,718	118,242	100,360	139,155	115,525	99,599	128,752	126,784	109,480	92,659
Flue Gas Analysis (%vol-dry)										
Argon	0.98%	0.98%	0.98%	0.98%	0.97%	0.96%	0.97%	0.97%	0.96%	0.96%
Nitrogen	81.12%	81.24%	81.13%	81.15%	81.19%	81.07%	81.27%	81.24%	81.17%	80.96%
Oxygen	13.89%	13.60%	13.86%	13.80%	13.72%	14.01%	13.54%	13.63%	13.76%	14.25%
Carbon Dioxide	4.02%	4.18%	4.04%	4.07%	4.12%	3.96%	4.22%	4.18%	4.10%	3.83%
Water	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Molecular Weight	29.33	29.35	29.33	29.33	29.33	29.32	29.34	29.34	29.33	29.31
Emission Rates, g/s										
NO_x	3.36	2.74	2.33	3.23	2.68	2.31	2.98	2.94	2.54	2.15
CO	1.38	1.13	0.96	1.33	1.10	0.95	1.23	1.21	1.04	0.88
VOC	0.29	0.23	0.20	0.28	0.23	0.20	0.24	0.24	0.21	0.19
SO_2	0.35	0.28	0.22	0.32	0.26	0.21	0.29	0.28	0.23	0.18
H_2SO_4	0.40	0.32	0.26	0.37	0.30	0.24	0.33	0.32	0.27	0.21
PM/PM-10	2.87	2.77	2.67	2.82	2.73	2.65	2.78	2.76	2.69	2.62

Table B-5
Indian Point Peaking Facility
Startup Emissions Analysis

Start-Up Type		**Startup**	**Shut Down**
Time Off Before/After Event (hr)		12	N/A[a]
Number of Events per Year		260	
Duration (hr)		0.3	0.3
NO_x			
Stack Emissions	lb/event	26	26
Steady-State Emission Rate[b]	lb/hr	25.6	
Emission Credit for Down Time	lb/event	307	
PTE Increase per Event	lb/event	0	
CO			
Stack Emissions	lb/event	84	84
Steady-State Emission Rate[b]	lb/hr	10.5	
Emission Credit for Down Time	lb/event	126	
PTE Increase per Event	lb/event	42	
VOC			
Stack Emissions	lb/event	5	5
Steady-State Emission Rate[b]	lb/hr	2.2	
Emission Credit for Down Time	lb/event	26	
PTE Increase per Event	lb/event	0	

NO_x		
CT Unit PTE (2 units) =	224	tpy
Increase due to Cold Start-Up =	0	tpy
Revised CT/HRSG Total PTE =	**224**	tpy
CO		
CT Unit PTE (2 units) =	92	tpy
Increase due to Cold Start-Up =	5	tpy
Revised CT/HRSG Total PTE =	**98**	tpy
VOC		
CT Unit PTE (2 units) =	19	tpy
Increase due to Cold Start-Up =	0	tpy
Revised CT/HRSG Total PTE =	**19**	tpy

a) Downtime is credited to start-up only, but emissions for one shutdown per start are included in PTE

b) Steady state emission rate is 100% load operation of one turbine at 50 °F.

Table B-6
Indian Point Peaking Facility
Non-Criteria Emission Calculations - Turbine

General Electric 7FA Combustion Turbine

Case No.	Fuel	Ambient Temp (°F)	Turbine Load (%)	CTG HHV Fuel Rate (mmBtu/hr)
1	Natural Gas	-10	BASE	1,979
2	Natural Gas	-10	75%	1,590
3	Natural Gas	-10	50%	1,259
4	Natural Gas	50	BASE	1,804
5	Natural Gas	50	75%	1,467
6	Natural Gas	50	50%	1,174
7	Natural Gas	100	BASE	1,633
8	Natural Gas	100	BASE	1,574
9	Natural Gas	100	75%	1,320
10	Natural Gas	100	50%	1,044

Pollutant	Notes	Emission Factor lb/mmCF	Emission Factor (lb/mmBtu) Natural Gas Turbine	Emissions (lb/hr) 1	2	3	4	5	6	7	8	9	10
1,3-Butadiene	(1)		< 4.30E-07	8.51E-04	6.84E-04	5.41E-04	7.76E-04	6.31E-04	5.05E-04	7.02E-04	6.77E-04	5.67E-04	4.49E-04
Acenaphthene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Acenaphthylene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Acetaldehyde	(1)		4.00E-05	7.91E-02	6.36E-02	5.04E-02	7.22E-02	5.87E-02	4.69E-02	6.53E-02	6.30E-02	5.28E-02	4.18E-02
Acrolein	(1)		6.40E-06	1.27E-02	1.02E-02	8.06E-03	1.15E-02	9.39E-03	7.51E-03	1.05E-02	1.01E-02	8.45E-03	6.68E-03
Ammonia	(3)			2.46E+01	2.01E+01	1.71E+01	2.37E+01	1.96E+01	1.69E+01	2.19E+01	2.16E+01	1.86E+01	0.00E+00
Anthracene	(2)		< 1.14E-07	2.25E-04	1.81E-04	1.43E-04	2.05E-04	1.67E-04	1.34E-04	1.86E-04	1.79E-04	1.50E-04	1.19E-04
Benz(a)anthracene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Benzene	(1)		1.20E-05	2.37E-02	1.91E-02	1.51E-02	2.17E-02	1.76E-02	1.41E-02	1.96E-02	1.89E-02	1.58E-02	1.25E-02
Benzo(a)pyrene	(2)		< 5.69E-08	1.13E-04	9.05E-05	7.16E-05	1.03E-04	8.35E-05	6.68E-05	9.29E-05	8.95E-05	7.51E-05	5.94E-05
Benzo(b)fluoranthene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Benzo(g,h,I)perylene	(2)		< 5.69E-08	1.13E-04	9.05E-05	7.16E-05	1.03E-04	8.35E-05	6.68E-05	9.29E-05	8.95E-05	7.51E-05	5.94E-05
Benzo(k)fluoranthene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Chrysene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Dibenz(a,h)anthracene	(2)		< 5.69E-08	1.13E-04	9.05E-05	7.16E-05	1.03E-04	8.35E-05	6.68E-05	9.29E-05	8.95E-05	7.51E-05	5.94E-05
Ethylbenzene	(1)		3.20E-05	6.33E-02	5.09E-02	4.03E-02	5.77E-02	4.69E-02	3.76E-02	5.23E-02	5.04E-02	4.22E-02	3.34E-02
Fluoranthene	(2)		1.42E-07	2.81E-04	2.26E-04	1.79E-04	2.57E-04	2.09E-04	1.67E-04	2.32E-04	2.24E-04	1.88E-04	1.49E-04
Fluorene	(2)		1.33E-07	2.63E-04	2.11E-04	1.67E-04	2.40E-04	1.95E-04	1.56E-04	2.17E-04	2.09E-04	1.75E-04	1.39E-04
Formaldehyde	(4)		1.30E-04	2.57E-01	2.07E-01	1.64E-01	2.35E-01	1.91E-01	1.53E-01	2.12E-01	2.05E-01	1.72E-01	1.36E-01
Indeno(1,2,3-cd)pyrene	(2)		< 8.53E-08	1.69E-04	1.36E-04	1.07E-04	1.54E-04	1.25E-04	1.00E-04	1.39E-04	1.34E-04	1.13E-04	8.91E-05
Naphthalene	(1)		1.30E-06	2.57E-03	2.07E-03	1.64E-03	2.35E-03	1.91E-03	1.53E-03	2.12E-03	2.05E-03	1.72E-03	1.36E-03
PAHs	(1)		2.20E-06	4.35E-03	3.50E-03	2.77E-03	3.97E-03	3.23E-03	2.58E-03	3.59E-03	3.46E-03	2.90E-03	2.30E-03
Phenanthrene	(2)		8.06E-07	1.59E-03	1.28E-03	1.01E-03	1.45E-03	1.18E-03	9.46E-04	1.32E-03	1.27E-03	1.06E-03	8.42E-04
Propylene Oxide	(1)		< 2.90E-05	5.74E-02	4.61E-02	3.65E-02	5.23E-02	4.25E-02	3.40E-02	4.74E-02	4.56E-02	3.83E-02	3.03E-02
Pyrene	(2)		2.37E-07	4.69E-04	3.77E-04	2.98E-04	4.28E-04	3.48E-04	2.78E-04	3.87E-04	3.73E-04	3.13E-04	2.48E-04
Sulfuric Acid	(5)			3.18E+00	2.56E+00	2.02E+00	2.90E+00	2.36E+00	1.89E+00	2.63E+00	2.53E+00	2.12E+00	0.00E+00
Toluene	(1)		1.30E-04	2.57E-01	2.07E-01	1.64E-01	2.35E-01	1.91E-01	1.53E-01	2.12E-01	2.05E-01	1.72E-01	1.36E-01
Xylenes	(1)		6.40E-05	1.27E-01	1.02E-01	8.06E-02	1.15E-01	9.39E-02	7.51E-02	1.05E-01	1.01E-01	8.45E-02	6.68E-02

Pollutant	Potential Emissions (g/s) 1	2	3	4	5	6	7	8	9	10	Annual Potential Emissions (6) (ton/yr)
1,3-Butadiene	1.07E-04	8.61E-05	6.82E-05	9.78E-05	7.95E-05	6.36E-05	8.85E-05	8.53E-05	7.15E-05	5.66E-05	6.80E-03
Acenaphthene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Acenaphthylene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Acetaldehyde	9.97E-03	8.01E-03	6.34E-03	9.09E-03	7.39E-03	5.92E-03	8.23E-03	7.93E-03	6.65E-03	5.26E-03	6.32E-01
Acrolein	1.60E-03	1.28E-03	1.02E-03	1.45E-03	1.18E-03	9.46E-04	1.32E-03	1.27E-03	1.06E-03	8.42E-04	1.01E-01
Ammonia	3.10E+00	2.53E+00	2.15E+00	2.98E+00	2.47E+00	2.13E+00	2.76E+00	2.72E+00	2.35E+00	0.00E+00	2.07E+02
Anthracene	2.84E-05	2.28E-05	1.80E-05	2.59E-05	2.10E-05	1.68E-05	2.34E-05	2.26E-05	1.89E-05	1.50E-05	1.80E-03
Benz(a)anthracene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Benzene	2.99E-03	2.40E-03	1.90E-03	2.73E-03	2.22E-03	1.77E-03	2.47E-03	2.38E-03	2.00E-03	1.58E-03	1.90E-01
Benzo(a)pyrene	1.42E-05	1.14E-05	9.02E-06	1.29E-05	1.05E-05	8.41E-06	1.17E-05	1.13E-05	9.46E-06	7.49E-06	8.99E-04
Benzo(b)fluoranthene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Benzo(g,h,I)perylene	1.42E-05	1.14E-05	9.02E-06	1.29E-05	1.05E-05	8.41E-06	1.17E-05	1.13E-05	9.46E-06	7.49E-06	8.99E-04
Benzo(k)fluoranthene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Chrysene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Dibenz(a,h)anthracene	1.42E-05	1.14E-05	9.02E-06	1.29E-05	1.05E-05	8.41E-06	1.17E-05	1.13E-05	9.46E-06	7.49E-06	8.99E-04
Ethylbenzene	7.98E-03	6.41E-03	5.08E-03	7.27E-03	5.91E-03	4.73E-03	6.59E-03	6.35E-03	5.32E-03	4.21E-03	5.06E-01
Fluoranthene	3.55E-05	2.85E-05	2.26E-05	3.23E-05	2.63E-05	2.10E-05	2.93E-05	2.82E-05	2.37E-05	1.87E-05	2.25E-03
Fluorene	3.31E-05	2.66E-05	2.11E-05	3.02E-05	2.45E-05	1.96E-05	2.73E-05	2.63E-05	2.21E-05	1.75E-05	2.10E-03
Formaldehyde	3.24E-02	2.60E-02	2.06E-02	2.96E-02	2.40E-02	1.92E-02	2.68E-02	2.58E-02	2.16E-02	1.71E-02	2.05E+00
Indeno(1,2,3-cd)pyrene	2.13E-05	1.71E-05	1.35E-05	1.94E-05	1.58E-05	1.26E-05	1.76E-05	1.69E-05	1.42E-05	1.12E-05	1.35E-03
Naphthalene	3.24E-04	2.60E-04	2.06E-04	2.96E-04	2.40E-04	1.92E-04	2.68E-04	2.58E-04	2.16E-04	1.71E-04	2.05E-02
PAHs	5.48E-04	4.41E-04	3.49E-04	5.00E-04	4.07E-04	3.25E-04	4.53E-04	4.36E-04	3.66E-04	2.89E-04	3.48E-02
Phenanthrene	2.01E-04	1.61E-04	1.28E-04	1.83E-04	1.49E-04	1.19E-04	1.66E-04	1.60E-04	1.34E-04	1.06E-04	1.27E-02
Propylene Oxide	7.23E-03	5.81E-03	4.60E-03	6.59E-03	5.36E-03	4.29E-03	5.97E-03	5.75E-03	4.82E-03	3.82E-03	4.58E-01
Pyrene	5.91E-05	4.75E-05	3.76E-05	5.39E-05	4.38E-05	3.51E-05	4.88E-05	4.70E-05	3.94E-05	3.12E-05	3.75E-03
Suluric Acid	4.01E-01	3.22E-01	2.55E-01	3.66E-01	2.97E-01	2.38E-01	3.31E-01	3.19E-01	2.67E-01	0.00E+00	2.54E+01
Toluene	3.24E-02	2.60E-02	2.06E-02	2.96E-02	2.40E-02	1.92E-02	2.68E-02	2.58E-02	2.16E-02	1.71E-02	2.05E+00
o-Xylene	1.60E-02	1.28E-02	1.02E-02	1.45E-02	1.18E-02	9.46E-03	1.32E-02	1.27E-02	1.06E-02	8.42E-03	1.01E+00

Emission factors prefixed with a "less than" symbol (<) indicate that the compound was not detected. The presented emission value is based on one-half of the detection limit.

(1) Turbine emission data from AP-42 Section 3.1 Table 3.1-3 (dated 4/2000)
(2) PAHs are broken out for turbines using the same split for boilers:

Natural Gas Fuel HHV	1020	Btu/scf
Total turbine PAH	2.20E-06	lb/mmBtu from AP-42 Table 3.1-3

Pollutant	AP-42 Emission Factor (lb/mmCF)	Emission Factor (lb/mmBtu)	Percent of Total (%)	Calculated Emission Factor (lb/mmBtu)
Acenaphthene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Acenaphthylene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Anthracene	< 2.40E-06	2.35E-09	5.17%	1.14E-07
Benz(a)Anthracene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Benzo(a)pyrene	< 1.20E-06	1.18E-09	2.59%	5.69E-08
Benzo(b)fluoranthene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Benzo(g,h,I)perylene	< 1.20E-06	1.18E-09	2.59%	5.69E-08
Benzo(k)fluoranthene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Chrysene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Dibenzo(a,h)anthracene	< 1.20E-06	1.18E-09	2.59%	5.69E-08
Fluoranthene	3.00E-06	2.94E-09	6.47%	1.42E-07
Fluorene	2.80E-06	2.75E-09	6.03%	1.33E-07
Indeno(1,2,3-cd)pyrene	< 1.80E-06	1.76E-09	3.88%	8.53E-08
Phenanathrene	1.70E-05	1.67E-08	36.64%	8.06E-07
Pyrene	5.00E-06	4.90E-09	10.78%	2.37E-07
Totals	4.64E-05	4.55E-08	100.00%	2.20E-06

AP-42 Emission factors from AP-42 Table 1.4-3 (dated 7/1998)

(3) Ammonia emissions based on an "ammonia slip" of 10 ppm
(4) Formaldehyde emission factor obtained from vendor test data.
(5) Sulfuric Acid Mist emission based on a natural gas sulfur content of 0.5 grains/100scf and a 75% SO_2 to SO_3 conversion.
(6) Based on 50 deg F, Base load 8760 hours per year

Table B-7
Indian Point Peaking Facility
Emissions Summary - Fuel Gas Preheaters

1	number of heaters in operation at one time
11.8	mmBtu/hr heat input (per heater)
1,020	Btu/scf fuel HHV
8760	operating hours/year

Criteria	Pollutant[1],[2],[3]					
	NO_x	CO	VOC	PM-10	SO_2	H_2SO_4
lb/mmBtu	0.1100	0.0400	0.0250	0.0090	0.0014	0.00011
lb/hr/unit	1.30	0.47	0.30	0.11	0.0165	0.0013
g/s/unit	0.16	0.06	0.04	0.01	0.002	0.0002
tons/yr/unit	5.69	2.07	1.29	0.47	0.072	0.0055
tons/yr total	**5.69**	**2.07**	**1.29**	**0.47**	**0.072**	**0.006**

Notes:

1) NO_x, CO, PM, and VOC emissions are based on vendor guarantees.
2) Emissions of SO_2 from the fuel gas heater are based upon a mass balance assuming all available elemental sulfur is converted to SO_2 during combustion.

Natural Gas	0.5	gr/100 scf
	7000	gr/lb
SO_2 MW	64	lb/lbmol
S MW	32	lb/lbmol

3) Sulfuric acid emissions are based on the sulfur content of the fuel and 5 % conversion of SO_2 to H_2SO_4

H_2SO_4 MW	98	lb/lbmol

STACK PARAMETERS (per stack)		
Exhaust Temperature	805	degrees F
	702.6	K
Exit Velocity	58.0	ft/s
	17.7	m/s
Stack Height	94.0	ft
	28.7	m
Stack Inner Diameter	12.3	in
	1.0	ft
	0.3	m

Table B-8
Indian Point Peaking Facility
Non-Criteria Emissions - Heater

	Heat Input Rates (mmBtu/hr)	Operating Hours (hrs/year)
Fuel Gas Heater	11.8	8760

Pollutant	Fuel Gas Heater [1] Emission Factor (lb/mmcf)	Emission Factor (lb/mmBtu)	Emissions (lb/hr)
2-Methylnapthalene	2.40E-05	2.35E-08	2.78E-07
3-Methylchloranthrene	1.80E-06	1.76E-09	2.08E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1.85E-07
Acenaphthene	1.80E-06	1.76E-09	2.08E-08
Acenaphthylene	1.80E-06	1.76E-09	2.08E-08
Anthracene	2.40E-06	2.35E-09	2.78E-08
Arsenic	2.00E-04	1.96E-07	2.31E-06
Benz(a)anthracene	1.80E-06	1.76E-09	2.08E-08
Benzene	2.10E-03	2.06E-06	2.43E-05
Benzo(a)pyrene	1.20E-06	1.18E-09	1.39E-08
Benzo(b)fluoranthene	1.80E-06	1.76E-09	2.08E-08
Benzo(g,h,i)perylene	1.20E-06	1.18E-09	1.39E-08
Benzo(k)fluoranthene	1.80E-06	1.76E-09	2.08E-08
Beryllium	1.20E-05	1.18E-08	1.39E-07
Cadmium	1.10E-03	1.08E-06	1.27E-05
Chromium	1.40E-03	1.37E-06	1.62E-05
Chrysene	1.80E-06	1.76E-09	2.08E-08
Cobalt	8.40E-05	8.24E-08	9.72E-07
Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	1.39E-08
Dichlorobenzene	1.20E-03	1.18E-06	1.39E-05
Fluoranthene	3.00E-06	2.94E-09	3.47E-08
Fluorene	2.80E-06	2.75E-09	3.24E-08
Formaldehyde	7.50E-02	7.35E-05	8.68E-04
Hexane	1.80E+00	1.76E-03	2.08E-02
Indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	2.08E-08
Manganese	3.80E-04	3.73E-07	4.40E-06
Mercury	2.60E-04	2.55E-07	3.01E-06
Napthalene	6.10E-04	5.98E-07	7.06E-06
Nickel	2.10E-03	2.06E-06	2.43E-05
Phenanathrene	1.70E-05	1.67E-08	1.97E-07
Pyrene	5.00E-06	4.90E-09	5.78E-08
Selenium	2.40E-05	2.35E-08	2.78E-07
Toluene	3.40E-03	3.33E-06	3.93E-05

(1) Emissions based on AP-42 5th Edition, Tables 1.4-3 and 1.4-4 (July 1998).

APPENDIX C

AGENCY CORRESPONDENCE

New York State Department of Environmental Conservation
Division of Air Resources
Bureau of Technical Support, 3rd Floor
625 Broadway, Albany, New York 12233-3253
Phone: (518) 402-8529 • **FAX:** (518) 402-9035
Website: www.dec.state.ny.us

Erin M. Crotty
Commissioner

April 26, 2002

Anthony P. Letizia
TRC Environmental Corporation
1200 Wall Street West, 2nd Floor
Lyndhurst, New Jersey 07071

Dear Mr. Letizia,

We have completed our review of the March, 2001 modeling protocol for the Indian Point Peaking Facility and find the document acceptable in general. Listed below are a few items to be incorporated in the air quality impact assessment (AQIA).

1. The facility map (Fig 3-1) should identify the fence line. It is assumed that the darkened line encompassing the facility is the fence line, but in the absence of a legend, this is not clear.

2. When the discussion regarding GEP stack height is presented in the AQIA, you must provide a detailed explanation for not building stacks to formula GEP height as per Air Guide 26 guidance. Low projected impacts and a brief statement related to aesthetics are insufficient reasons by themselves.

3. Since the CTSCREEN methodology was not included in the protocol, approval of the CTSCREEN methodology cannot be given until it is reviewed in the AQIA. If CTSCREEN is used, then intermediate terrain must be addressed.

4. The names the background air quality monitors in addition to their numbers and general location ("New York City") should be included in Table 5-3. In addition, the concentrations should be expressed in both PPM and ugm^{-3}. It appears that some of the numbers in Table 5-3 do not match the latest data contained in our air monitoring archives.

5. When constructing the maximum impact and standards compliance tables, the year and location of the maximum impacts should be identified.

6. According to Article X rules, a section devoted to $PM_{2.5}$ impacts should be included in the AQIA.

If you have any questions regarding these comments, you can reach me directly at 518-402-8527.

Sincerely,

Robert S. Gaza, Ph. D.
Impact Assessment and Meteorology
Bureau of Technical Support
NYSDEC

cc: L. Sedefian
G. Sweikert (Region 3)
C. Hogan
B. Little
R. Orr

TRC

Customer-Focused Solutions

March 22, 2002
AL045-02

Via Federal Express

Mr. Leon Sedefian
Air Pollution Meteorologist V
New York State Department of Environmental Conservation
Division of Air Resources, Bureau of Technical Services
625 Broadway
Albany, New York 12233-3250

Subject: **Entergy Indian Point Peaking Facility, LLC – Indian Point Peaking Facility Village of Buchanan, Westchester County, New York Air Quality Modeling Protocol**

Dear Mr. Sedefian:

Enclosed please find three (3) copies of the modeling protocol prepared for the proposed Indian Point Peaking Facility. The proposed project is a nominal 330 megawatt, simple-cycle peaking electric generating facility to be developed by Entergy Indian Point Peaking Facility, LLC on an approximate 5-acre parcel of land within the existing Indian Point Nuclear Generating Station Unit No. 3 property located in the Village of Buchanan, Westchester County.

The enclosed protocol addresses the methods for assessing the air quality impacts based on atmospheric dispersion modeling. A discussion of the methods for assessing the visible plume formation from the turbine stack is also included. Because the project is not proposing to use an evaporative cooling tower, no discussion of SACTI modeling has been included. Additional detail has been provided in the subject protocol, beyond which is normally contained in a standard modeling protocol (i.e., for a facility subject to only Part 201 Air State Facility permitting). This detail has been included to support the public involvement requirement of the Article X process.

We appreciate this opportunity to continue to work with you and you staff and look forward to receiving your comments. Please feel free to contact me at (201) 933-5541 ext. 115 or Ted Main of TRC at ext. 114 should you have any questions on this modeling protocol.

Yours truly,

TRC Environmental Corporation

Anthony P. Letizia
Vice President

Enclosure

cc: C. Hogan, NYSDEC (w/enclosure)
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TRC
Customer-Focused Solutions

Entergy Indian Point Peaking Facility, LLC
Indian Point Peaking Facility
Village of Buchanan, New York

Air Quality Modeling Protocol

Prepared for

New York State
Department of Environmental Conservation

Prepared by

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1.0 INTRODUCTION

Entergy Indian Point Peaking Facility, LLC (Entergy) proposes to construct a nominal 330-megawatt (MW) simple-cycle peaking electric generating facility (proposed Facility) approximately five-acres of land within the property of the existing Indian Point 3 Nuclear Generating Station located in the Village of Buchanan, Westchester County, New York. Prevention of Significant Deterioration (PSD) Rules will not apply to the proposed Facility since potential emissions of all criteria pollutants will be below the 250 tons per year (tpy) major source threshold. Although the proposed Facility is not subject to PSD review, it does require a New York Codes, Rules, and Regulations (NYCRR) Part 201 Air Permit. Under the Part 201 requirements, it must be demonstrated that emissions of each subject pollutant will be in compliance with the National and New York Ambient Air Quality Standards (NAAQS and NYAAQS), and comply with PSD Class II air quality increments (as a minor source). Non-Attainment New Source Review (NNSR) rules apply to nitrogen oxides (NO_x) and volatile organic compound (VOC) emissions (as precursors to the non-attainment pollutant ozone) if Facility emissions will exceed the 25 tpy threshold. New York State Article X Power Plant Siting Requirements apply to the facility since its power generating capability will be above the Article X applicability threshold of 80 MW. This modeling protocol presents in detail the techniques proposed for completing the air quality evaluation.

On October 15, 2001, representatives from Entergy and TRC Environmental Corporation (TRC), environmental consultant on the project, attended a pre-application meeting with representatives of the New York State Department of Environmental Conservation (NYSDEC) in Albany, New York. The attendees discussed key issues related to the permitting of the proposed Facility, including modeling, monitoring, NNSR, Lowest Achievable Emission Rate (LAER), and additional required analyses. The following modeling protocol incorporates elements discussed at the October 15th meeting, as well as established regulatory guidance specific to the performance of an impact assessment as described in the United States Environmental Protection Agency (U.S. EPA) Modeling Guidelines (U.S. EPA, 2001) and the NYSDEC's Air Guide Series.

In addition, the New York State Department of Health (NYSDOH) requires that potential toxic air pollutant emissions from proposed sources be evaluated to ensure that maximum ambient air concentrations are less than benchmark air concentrations developed for prior Article X projects after consultation with the NYSDOH. Potential toxic air pollutant emissions from all proposed sources at the Facility will be modeled for comparison to the benchmark concentrations.

2.0 AREA DESCRIPTION

The proposed Facility will be constructed on approximately five acres of property currently held by Entergy Nuclear Indian Point 3, LLC, and located in the Village of Buchanan, Westchester County, New York.

The Facility site is used for temporary storage of various maintenance materials and equipment and parking. Key features of the site include its industrial status, the amount of acreage available, its proximity to the Algonquin gas transmission line, and its proximity to Con Edison's Buchanan 138-kV electrical substation.

The Facility site is located on the east bank of the Hudson River in the Village of Buchanan, approximately 35 miles north of New York City. The terrain rises very rapidly northwest of the site. Across the Hudson River, approximately 2 miles northwest of the site, Bald Mountain (on Dunderberg Mountain) rises to an elevation of 1,120 feet above mean sea level (MSL). Approximately 4 miles northwest of the site, in Bear Mountain State Park, Bear Mountain rises to an elevation of 1,284 feet above MSL. Less rugged terrain prevails east of the site.

The elevation (topography) of the site has been altered due to construction of the Indian Point Nuclear Facility and is relatively uniform. Site elevation is approximately 114 feet above MSL. Topography proximate (within 1 kilometer) to the proposed Facility varies from river level at the Hudson River to approximately 145 feet above MSL just northeast of the site. The nearest topographic feature is approximately 2 kilometers to the northwest, at an elevation of 205 feet above MSL. This is the nearest location where terrain rises above the proposed stack top. Figure 2-1 presents the proposed Facility's location on a United States Geological Survey (USGS) 7.5-minute topographic map.

The Facility is located at approximately 41° 15' 53'' North Latitude, 73° 57' 21'' West Longitude. The approximate Universal Transverse Mercator (UTM) coordinates of the Facility are 587,467 meters Easting, 4,568,451 meters Northing, in Zone 18.

3.0 FACILITY DESCRIPTION

3.1 Equipment/Fuels

The proposed Facility is a 330-MW simple cycle power generation facility consisting of two General Electric (GE) 7FA combustion turbines. The turbines will employ dry low-NO_x (DLN) combustion and high-temperature selective catalytic reduction (SCR) to control emissions of nitrogen oxides (NO_x). Upon leaving the SCR system, turbine exhaust gases will be directed to two individual 90-foot stacks. Auxiliary equipment will include two fuel gas heaters. The proposed Facility will use natural gas as the exclusive fuel for the combustion turbines and the fuel gas heaters.

3.2 Operation

The two simple cycle combustion turbines will serve as peaking units and supply power during periods of high power demand. Depending upon electric power demand, either one or both turbines will operate at any given time. Each turbine will be capable of operating between 50 percent and 100 percent load. Only one of the fuel gas heaters will operate at any given time. The other one will serve as backup. Therefore, a load screening analysis for the turbines will be performed to determine the impacts for the turbines operating at 100%, 75%, and 50% load conditions. The worst-case turbine operating scenarios for each pollutant and averaging period will then be modeled with the fuel gas heater.

3.3 Stack Configuration And Emission Parameters

The two combustion turbines will emit treated exhaust gas through two individual stacks. The stacks will be constructed to a height of 90 feet above grade level (AGL). Two fuel gas heaters will also emit exhaust gas to a third 90 foot AGL stack. The base elevation of the proposed Facility is 114 feet above MSL.

Exhaust parameters for the turbines and fuel gas heaters are provided in Tables 3-1 and 3-2, respectively. Exhaust parameters for the combustion turbines are presented for three ambient temperatures (-10°F, 50°F, and 100°F) and three loads (100%, 75%, and 50%) for gas fired operation. These ambient temperatures are consistent with NYSDEC guidance received at a pre-application meeting held on October 15, 2001. Table 3-3 presents the potential emission rates for each of the operating scenarios for the combustion turbines. Table 3-4 presents the potential emission rates for the fuel gas heater. Emission rates and stack parameters for all ambient temperatures, and operating load combinations will be used in the load screening modeling analysis.

Emissions of toxic air pollutants from the turbines and fuel gas heaters will also be assessed in the modeling analysis. The U.S. EPA's AP-42 emission factors and those provided by vendors will be used to estimate emissions of toxic air pollutants from the turbine stacks and fuel gas heaters.

3.4 Good Engineering Practice Stack Height

Section 123 of the Clean Air Act Amendments (CAAA) required U.S. EPA to promulgate regulations to assure that the control of any air pollutant under an applicable State Implementation Plan (SIP) was not affected by: 1) stack heights that exceed Good Engineering Practice (GEP), or 2) any other dispersion technique. The U.S. EPA's Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations), (U.S. EPA, 1985) provides specific guidance for determining GEP stack height and for determining whether building downwash will occur. GEP is defined as "the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain "obstacles"."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which adverse aerodynamics (downwash) are avoided.

The U.S. EPA GEP stack height regulations specify that the GEP stack height be calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

where: H_B = the height of adjacent or nearby structures, and
L = the lesser dimension (height or projected width of the adjacent or nearby structures)

The proposed Facility will be designed with two individual combustion turbine stacks and one fuel gas heater stack. Preliminary studies have been conducted to determine a stack height that will be sufficiently low to minimize visibility of the stacks, yet tall enough to result in minimal air quality impacts. The results of these studies and the preliminary site layout indicate that the stacks will be 90 feet AGL, which is below the GEP height determined from the proposed structures at the Facility site. The controlling structures for the proposed stacks for "downwash" purposes will be the two new filter houses. The filter houses will have heights of 78.2 feet AGL. The GEP stack height was calculated to be 151 feet AGL. The controlling structure for the proposed stacks for "cavity effects" purposes will be the new SCR building. The SCR building will have a height of 60 feet AGL. At 90 feet AGL, the simple cycle stacks and fuel gas heater stack will be 1.5 times the new SCR building height, outside the turbulent cavity zone. A stack height of at least 1.5 times the controlling structure is sufficient to avoid entrainment of the emissions into the recirculation zone (or cavity), behind the structure. The filter houses are not considered controlling structures from a "cavity effects" perspective since the air inlet would draw in any emissions behind the inlet filter structure. A GEP stack analysis will be provided as part of the Air Permit Application and Article X Application.

Because the proposed turbine stacks and fuel gas heater stack will be non-GEP, direction-specific building downwash parameters will be input to the Industrial Source Complex Short-Term (ISCST3) model. The U.S. EPA Building Profile Input Program (BPIP, Version 95086) was used to determine the directionally dependent building dimensions for input into the modeling analysis. A detailed plot plan of the proposed facility has been provided in Figure 3-1.

Table 3-1: GE 7FA Combustion Turbine Stack Parameters

Case	Turbine Load (%)	Fuel Type	Ambient Temperature (F)	Exhaust Temperature (K)	Exhaust Velocity[b] (m/s)	Stack Diameter[a] (m)
Case01	100	Gas	-10	783.2	23.1	8.32
Case02	75	Gas	-10	783.2	19.0	8.32
Case03	50	Gas	-10	783.2	16.2	8.32
Case04	100	Gas	50	783.2	22.2	8.32
Case05	75	Gas	50	783.2	18.3	8.32
Case06	50	Gas	50	783.2	15.7	8.32
Case07	100	Gas	100	783.2	21.1	8.32
Case08	75	Gas	100	783.2	17.9	8.32
Case09	50	Gas	100	783.2	15.2	8.32

[a]Effective diameter calculated to be 27.29 feet (8.32 meters) from a rectangular stack with dimensions 45 feet x 13 feet.
[b]Exhaust velocities calculated using an effective stack diameter of 27.29 feet (8.32 meters).

Table 3-2: Fuel Gas Heater Stack Parameters

Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)
702.59	17.68	0.31

Note: These values are preliminary and subject to change.

Table 3-3: GE 7FA Combustion Turbine Potential Emission Rates

Case	Potential Emission Rate[a] (lb/hr)			
	NO_x	CO	PM-10	SO_2
Case01	17.97	33.00	18.85	2.73
Case02	14.49	25.00	18.68	2.20
Case03	11.48	20.00	18.54	1.75
Case04	16.62	30.00	18.78	2.53
Case05	13.48	24.00	18.63	2.05
Case06	10.78	20.00	18.51	1.64
Case07	15.38	27.00	18.72	2.34
Case08	12.59	22.00	18.59	1.91
Case09	10.01	19.00	18.47	1.52

[a]Potential emission rates per turbine.

Table 3-4: Fuel Gas Heater Potential Emission Rates

(lb/hr per unit)			
NO_x	CO	PM-10	SO_2
0.34	0.58	0.05	0.01

Note: These values are preliminary and subject to change.

4.0 REGULATORY REQUIREMENTS

4.1 Attainment Status And Compliance With Air Quality Standards

The proposed Facility is located in an area currently designated as attainment for SO_2, NO_X and PM-10. (Note that although the site area is currently designated as moderate non-attainment for CO, it is scheduled to be designated as attainment around the end of April 2002. Thus, for purposes of this document, CO will be treated as an attainment pollutant). Therefore, for these pollutants (including CO) the facility is required to demonstrate that the impact on air quality does not cause or contribute to a violation of the NAAQS or the NYAAQS. The NAAQS and NYAAQS for the criteria pollutants are shown in Table 4-1.

The area is designated as severe non-attainment for ozone (O_3). Therefore, facilities emitting more than 25 tpy of NO_X or VOC are subject to NNSR for these pollutants. NNSR requirements include the requirement to meet LAER levels and the need to obtain emission offsets. Preliminary facility emission rates presented in Table 4-2 indicate that the facility will be subject to NNSR for NO_X, but not for VOC.

4.2 Prevention Of Significant Deterioration

Simple cycle combustion turbine based power facilities with emissions greater than 250 tpy of any criteria pollutant are subject to PSD review. Preliminary annual emission rates for the proposed Facility in Table 4-2 indicates that projected emissions of all pollutants will be below the 250 tpy PSD threshold, thus the Facility is not subject to PSD permitting requirements. Note that the Facility is proposing to obtain a permit with federally enforceable annual emission caps of 225 tons and 22.5 tons for CO and VOC emissions, respectively.

Although the proposed Facility is not subject to PSD review, it does require a NYCRR Part 201 Air Permit. Under the Part 201 requirements, it must be demonstrated that emissions of each subject pollutant will be in compliance with the NAAQS and NYAAQS, and comply with PSD Class II air quality increments (as a minor source). The PSD Increments are presented in Table 4-3.

To determine if the proposed Facility will significantly impact the ambient air surrounding the Facility, a significant impact analysis will be required. The significant impact analysis consists of modeling the proposed Facility and comparing the maximum concentrations to each pollutant's significant impact level (SIL). The SILs are presented in Table 4-4. If the proposed Facility results in significant impacts (i.e., maximum impacts greater than the SIL), then the Facility is required to conduct a cumulative impact assessment to evaluate compliance with the NAAQS and PSD increments.

4.3 New York State Requirements

In addition to the previously discussed Federal Requirements, the proposed Facility must incorporate the New York State air quality requirements, where applicable, to the air quality assessment. These requirements are specified in:

- NYSDEC. 6 NYCRR Part 227-1 Stationary Combustion Installations
- NYSDEC. 6 NYCRR Part 227-2 NO_X RACT
- NYSDEC. 6 NYCRR Part 231 New Source Review in Non attainment Areas and Ozone Transport Regions
- NYSDEC. 6 NYCRR Part 257 Air Quality Standards
- NYSDEC. Air Guide - 12 Review of Major Sources (for PSD source review and increment consumption only)
- NYSDEC. Air Guide-21 Compliance Determinations for 6 NYCRR Part 225
- NYSDEC. Air Guide-26 Guideline on Modeling Procedures for Source Impact Analyses
- NYSDEC. Air Guide-1 Guidelines for the Control of Toxic Ambient Air Contaminants
- NYSDEC. Air Guide-36 Emissions Inventory Development for Cumulative Air Quality Impact Analysis (applicable only if major source inventory is required.)
- NYSDEC .Air Guide-39 Gas Turbine NO_x Policy

Table 4-1: National and New York Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)	NYAAQS ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-Hour	1,300[a]	1,300[a]
	24-Hour	365[a]	365[a]
	Annual	80[b]	80[b]
Nitrogen Dioxide (NO_2)	Annual	100[b]	100[b]
Particulate (PM-10)	24-Hour	150[c]	150[c]
	Annual	50[d]	50[d]
Total Suspended Particulate (TSP)	24-Hour	N/A	250[e]
	Annual	N/A	45[f]
Carbon Monoxide (CO)	1-Hour	40,000[a]	40,000[a]
	8-Hour	10,000[a]	10,000[a]
Ozone (O_3)	1-Hour	235[e]	160[a]

a Not to be exceeded more than once per year
b Not to be exceeded
c Fourth highest concentration over a three year period
d Average of three annual average concentrations
e Not to be exceeded more than once per year on average
f Geometric mean of the 24-hour average concentrations over 12-month period

Source: 40 CFR 50; 6 NYCRR 257; 40 CFR 52; and USEPA (1990), "New Source Review Workshop Manual-Draft."

Table 4-2: Preliminary Annual Facility Emission Rates

Pollutant[(a)]	Preliminary Annual Facility Emissions (TPY)[b]
Carbon Monoxide	225[c]
Sulfur Dioxide	22
PM	165
PM-10	165
Nitrogen Oxides	146
VOC	22.5[c]
Sulfuric Acid Mist	5
HAP	<10

[a]Regulated substances not emitted by the proposed Facility have not been included in the table.
[b]Based on full year, full load operation.
[c]Limited by Federally enforceable emission caps.

Source: TRC, 2002.

Table 4-3: PSD Increments

Pollutant[a]	Class I Increment ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	Class III Increment ($\mu g/m^3$)
SO_2			
Annual [b]	2	20	40
24-Hour [c]	5	91	182
3-Hour [c]	25	512	700
PM-10			
Annual [b]	4	17	34
24-Hour [c]	8	30	60
NO_2			
Annual [b]	2.5	25	50

[a] There are no PSD increments established for CO
[b] Never to be exceeded
[c] Not to be exceeded more than once per year

Source: U.S. EPA, 1990; Table C-2.

Table 4-4: U.S. EPA Significant Impact Levels

Pollutant	Averaging Period	Significant Impact Level ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-hour 24-hour Annual	25 5 1
Nitrogen Dioxide (NO_2)	Annual	1
Carbon Monoxide (CO)	1-hour 8-hour	2,000 500
Particulates (as PM & PM-10)	24-hour Annual	5 1

Source: U.S. EPA, 1990; Table C-4.

5.0 MODELING METHODOLOGY

Dispersion modeling will be performed consistent with the procedures found in NYSDEC's Air Guide Series and U.S. EPA documents: the Guideline on Air Quality Models (Revised) (U.S. EPA, 2001); Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (Revised)(U.S. EPA, 1992); and, New Source Review Workshop Manual [Draft] (U.S. EPA, 1990). The toxic air pollutant modeling analysis will be conducted following the method agreed to by the NYSDOH and the applicant, which is described below. The following sections discuss the methodology for the proposed modeling analyses.

5.1 Dispersion Parameters

A land use classification analysis was performed to determine if urban or rural dispersion parameters should be used in quantifying ground-level concentrations. The analysis conforms to the procedures contained in the A.H. Auer paper "Correlation of Land Use and Cover with Meteorological Anomalies" (Auer, 1978). This procedure involves determining the percentages of various industrial, commercial, residential, and agricultural/natural areas within a 3-kilometer radius circle centered on the proposed site. If more than 50 percent of the area within this circle is designated I1, I2, C1, R2 and R3 (industrial, commercial, and compact residential), urban dispersion parameters should be used; otherwise, the modeling should use rural dispersion parameters. An evaluation of land use around the site has revealed that the area within 3-kilometers of the site may be classified as rural. The land use analysis is presented in more detail in Appendix A.

5.2 Dispersion Models

The ISCST3 model (version 02035) is proposed to assess the air quality impacts of the proposed Facility. Throughout this modeling protocol, "ISCST3" refers to Version 02035 unless otherwise specified. The ISCST3 model will be applied in accordance with the recommendations made in U.S. EPA's Guideline on Air Quality Models (Revised) (U.S. EPA, 2001).

The ISCST3 model was designed for assessing pollutant concentrations from a wide variety of sources (point, area, volume) associated with an industrial source complex. It has been designated by the U.S. EPA as a "preferred" model for use in rural or urban areas, flat or rolling terrain, transport distances less than 50 kilometers, and one hour to annual averaging times (U.S. EPA, 2001).

ISCST3 was developed for use in flat to gently rolling terrain, i.e., in terrain with elevations lower than stack height. It treats elevated terrain (elevations less than stack height) as follows:

- The plume axis remains at constant elevation as it passes over elevated or depressed terrain; i.e., the effective plume height decreases as terrain height increases;
- The mixing height is terrain-following; i.e., it remains constant as the plume passes over elevated or depressed terrain; and
- The change in wind speed is a function of emission height above the anemometer height.

In complex terrain (terrain with elevations above stack height), the ISCST3 model in default mode will use two algorithms for determining the concentration at the receptor. The default ISCST3 algorithm truncates the terrain elevation to stack top and performs a calculation with the reduced terrain elevation. However, ISCST3 also includes the COMPLEX I elevated terrain screening algorithm which handles dispersion in complex terrain in a different fashion. If the receptor is at an elevation above stack top but below the height of the final plume rise, then ISCST3 will calculate a concentration based on both the default ISCST3 method and the COMPLEX I method and present the higher of the two concentrations. ISCST3 will use only the COMPLEX I calculations for receptors at elevations above the final plume rise.

Because Entergy proposes to use 5 years of on-site meteorological data collected at the Facility, the ISCST3 model may be used to determine the impacts in complex terrain. Should ISCST3 yield concentrations above the SILs in complex terrain, Entergy proposes to use the U.S. EPA CTSCREEN (version 94111) complex terrain model. Although this is a conservative screening model, it is superior to ISCST3 for calculating impacts in complex terrain.

ISCST3 includes various input and output options. Additional options are available for specific methods to be used in plume model equations. The model will be applied using regulatory default (DFAULT keyword) options. These include the following:

- <u>Stack Tip Downwash</u>. U.S. EPA recommends this option for use in regulatory applications. When this option is implemented, a height increment is deducted from the physical stack height before computing plume rise, as recommended by Briggs (1974). The height increment to be deducted from the physical stack height depends upon the ratio of stack exit velocity to wind speed and is equal to 2d [1.5 – v_s/u], where v_s is the stack exit velocity, u is the wind speed, and d is the inside stack diameter. If v_s/u is greater than 1.5, the height increment is zero.

- Final Plume Rise. With this option, final plume rise is used for calculating the plume height to be used in estimating ground-level concentrations at all receptors. The final plume rise option will be used for ground-level receptor impact assessment. The selection of this option is consistent with U.S. EPA guidelines.

- Buoyancy-Induced Dispersion. This option causes modifications to the dispersion coefficient (σ_y and σ_z) calculations that account for enhanced dispersion due to turbulence caused by plume buoyancy (Pasquill, 1976). This results in a simulated plume with greater horizontal and vertical extent than would be simulated considering dispersion from ambient turbulence only. This option is applied only near the source, before the plume reaches its final height. It is a recommended option for regulatory applications.

- Vertical Potential Temperature Gradient. The vertical potential temperature gradient is used to calculate the stability parameters used in plume rise equations for stable conditions. Unless site-specific potential temperature gradients are provided, ISCST3 uses the default values shown in Table 5-1.

- Wind Profile Exponents. ISCST3 uses a power-law extrapolation of wind speeds from measurement height to plume height. Unless site-specific values are provided, ISCST3 uses the default values also shown in Table 5-1.

- Decay. An exponential decay term may be included in ISCST3 modeling to simulate removal processes. The decay coefficient may be universally applied to all calculations or entered with meteorological data on an hourly basis. No decay will be applied in this analysis.

- Wake Effects. Building wake effects may be simulated using procedures suggested by Huber and Snyder (1976) and Huber (1977). When the stack height is less than the building height plus one half the lesser of the building height or width, wake effects are simulated using procedures suggested by Schulman and Hanna (1986) and based on the work of Scire and Schulman (1980). Since the facility will employ non-GEP stacks, wake effects will be considered by using BPIP and directional dependent building dimensions in ISCST3.

- Calm Processing. When the calm processing option is implemented, calm conditions are handled according to methods developed by the U.S. EPA. When a calm is detected in the meteorological data, or the data are missing, the concentrations at all receptors are set to zero, and the number of hours being averaged is never less than 75 percent of the averaging time.

5.3 Meteorological Data

Refined meteorological data is used to determine air quality impacts using location specific dispersion conditions. Refined data must be representative of the dispersion characteristics of the area around the Facility, reliable and meet PSD quality assurance requirements.

TRC proposes to use the available meteorological data collected by the meteorological tower at the Indian Point Nuclear Generating Station from January 1996 through December 2000. This tower has been collecting data at the site for many years and is designed and operated in accordance with stringent United States Nuclear Regulatory Commission (NRC) meteorological monitoring guidelines that are similar to U.S. EPA guidelines. Table 5-2 presents a comparison of these two guidelines. The tower location is roughly the same elevation as the proposed site. Tower siting with respect to surrounding terrain influences is also similar to the terrain influencing the proposed site. The tower is located near the proposed stack locations. Data was recorded at 10 meters, 60 meters, and 122 meters AGL on the tower. Use of 10-meter data is proposed. These data are the most recent from an on-site monitoring program that continues to run today.

The data quality assurance and quality control procedures used during the data collection period included weekly visual inspections of all equipment, gross comparison of recorded data versus real conditions, semiannual electronic zero/span checks, and semiannual instrument and accuracy tests with independent equipment and standards. Overall data recovery for the proposed monitoring period ranged from 99.3% to 99.8%, which exceeds the 90% PSD monitoring guideline requirement. Based upon the above, TRC concludes that the Indian Point onsite data meet the siting, data recovery, and quality assurance criteria of the U.S. EPA PSD Monitoring Guidelines.

The Indian Point meteorological data were collected onsite; therefore, it is valid for use in both simple and complex terrain modeling analyses. TRC believes it is the most representative, available data for use in assessing air quality impacts of the proposed Facility. Therefore, TRC proposes to use the Indian Point meteorological data for all air quality modeling analyses required for the proposed Facility.

In addition to onsite meteorological data, the air quality impact modeling will require concurrent years of upper air meteorological data that will be used to calculate the mixing height in the atmosphere for use by the model. Upper air observations are taken by the National Weather Service (NWS) at a limited number of locations throughout the United States. The NWS upper air observation stations closest to the Facility site with available data for 1996-2000 are Albany, New York and Brookhaven National Labs, Upton, New York. A review of summarized mixing height data for 62 upper air stations in the United States, which was prepared by Holzworth (Holzworth. GC, 1972. Mixing Height, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States, U.S. EPA Office of Air Programs) indicates that the Albany mixing height data is the most representative of site conditions, and thus is proposed for use in the modeling study.

Concurrent years of surface meteorological data, in addition to both the onsite and mixing height data, are also needed to produce a model-ready meteorological data file. Stewart International Airport, approximately 7 kilometers west of Newburgh, New York, and 29 kilometers northwest of the Facility site, represents the closest representative NWS station with meteorological data available for modeling purposes.

The three meteorological datasets (onsite, mixing height, and surface) were processed using the Meteorological Processor for Regulatory Models (MPRM). MPRM creates a model-ready meteorological file that is used by ISCST3.

5.4 Receptor Grid

The ISCST3 model requires receptor data consisting of location coordinates and ground-level elevations. The receptor-generating program, AERMAP, will be used to develop a complete receptor grid to a distance of 15 kilometers from the proposed Facility. AERMAP uses digital elevation model (DEM) data obtained from the USGS. 1-degree (3-arc-second) DEM files will be obtained for an area covering at least 15 kilometers in all directions from the proposed Facility. AERMAP will be run to determine the representative elevations for each receptor.

A polar receptor grid consisting of receptors located along radials every 10 degrees from 10 degrees through 360 degrees (north) is proposed. The receptors will be spaced along the radials every 100 meters from the center of the Facility to 3.5 kilometers, every 250 meters from 3.75 kilometers to 8 kilometers, and every 1-kilometer from 9 kilometers to 15 kilometers. In addition, receptors will be placed every 25 meters along the fence line that precludes general public access. Any polar receptors located within the fence line will be removed. If the maximum-modeled concentrations are located in an area beyond the 100 meter spaced receptors, a Cartesian grid of 100 meter spaced receptors will be placed around the initial maximum-modeled concentration location to ensure the maximum-modeled concentration is located.

Furthermore, if concentrations are increasing at the 15,000-meter ring, an additional ring will be added to determine the distance at which concentrations begin to decrease.

5.4.1 Sensitive Receptors

A list of sensitive receptors will be developed for inclusion in the modeling analysis. USGS topographic maps and other current data sources will be reviewed for the area immediately surrounding the Facility site and noted sensitive receptors (day care and nursery schools, elementary, middle, and high schools, and other community facilities) will be identified. Information for these receptors will include the name of the facility, elevation of the terrain above MSL, and distance and direction from the proposed Facility.

5.5 Background Ambient Air Quality

As stated earlier, the proposed Facility will be located in Westchester County, which is currently designated as attainment for SO_2, NO_X, and PM-10. Ozone is designated as severe non-attainment and carbon monoxide is designated as moderate non-attainment. However, Westchester County is currently proposed to be designated attainment for CO around the end of April 2002. In the event the Facility emissions result in concentrations greater than the SILs, the maximum concentrations plus the concentrations of existing major sources plus a representative background concentration will be compared to the applicable ambient air quality standards.

SO_2 background data is proposed to be obtained from the NYSDEC monitor in Mt. Ninham (Putnam County), approximately 18 miles northeast of the proposed Facility. The SO_2 monitor at Mt. Ninham is located in a rural setting, similar to the proposed Facility, and has been collecting SO_2 background concentrations since 1994. PM-10 background data will be obtained from the NYSDEC Region 2 Mabel Dean High School Annex monitor in Manhattan (New York County), approximately 36 miles south of the proposed Facility. It should be noted that the area around this monitor is highly urbanized and provides a very conservative background concentration for the area surrounding the proposed Facility. There are no NYSDEC NO_2 or CO monitors within Region 3. Therefore, TRC proposes to use NO_2 and CO background concentrations from Bronx County in New York City, approximately 28 miles south of the proposed Facility. The NO_2 and CO concentrations recorded at this monitoring site will be reflective of a highly urbanized area, unlike the proposed Facility location; thus the background concentrations should be conservative estimates of the NO_2 and CO background concentrations at the proposed Facility.

These monitors are sufficiently close to the Facility location to be either representative or conservative estimates of the air quality within the project study area. Table 5-3 presents the maximum annual and highest second-highest short-term concentrations recorded during the latest three years (1998-2000) at the above stations for the specific criteria pollutants, which are proposed as a representative background for the proposed Facility.

The proposed Facility air quality concentrations will be added to representative background concentrations recorded at these stations and the sum will be compared to the NAAQS/ NYAAQS, if necessary.

5.6 Load Screening

In order to assess the worst-case emission conditions for the simple cycle turbines, a load screening analysis will be performed. Nine (9) combinations of load conditions and ambient operating temperatures will be calculated for gas firing for each turbine. The worst-case turbine operating scenarios for each pollutant and averaging period will then be modeled with the fuel gas heater. The load screening analysis will be performed using the full receptor grid with terrain and five years of refined meteorological data as identified is Sections 5.3 and 5.4. The operating condition that results in the maximum ambient impacts (i.e., worst case operating scenario) will be modeled in any subsequent modeling analyses (e.g., NAAQS).

5.7 Determination Of Significant Impacts

Refined modeling will be performed to determine if the Facility emissions result in significant air quality impacts. ISCST3 will be used for modeling the Facility with the 5-year on-site meteorological database. The highest concentrations at each receptor will be determined for each pollutant and compared to the SILs presented in Table 4-4.

If the impacts from the proposed Facility are determined to be significant (i.e., maximum modeled concentrations are greater than the SILs), then the area of impact will be determined for each pollutant/averaging period that is significant. The area of impact corresponds to the distance at which calculated concentrations fall below the SIL. All off-site major sources within the area of impact plus a NYSDEC recommended distance from the Facility will be included in a multiple major source NAAQS impact analysis. This distance will be based on discussion with the NYSDEC air quality evaluation staff, if necessary.

5.8 Off-Site Sources

In the event a major NAAQS analysis is required, the NYSDEC will be consulted at that time. These discussions will be centered on the development of an off-site source inventory and the procedures recommended to prepare a multiple source modeling analysis. The procedures to be used will be described in a separate multisource modeling protocol that will be submitted to the NYSDEC.

5.8.1 NAAQS/NYAAQS Impact

The proposed Facility will be assessed to determine the impact on the NAAQS and NYAAQS. A refined modeling analysis will be provided with the Part 201 Permit Application, which is anticipated to indicate that the Facility will not have a significant air quality impact. As discussed above, should a refined modeling analysis indicate the Facility would have significant air quality impacts, a multiple major source modeling analysis will be performed.

5.8.2 PSD Increment Impact

While the proposed Facility will not be subject to Federal PSD review requirements, NYSDEC requires that non-PSD sources demonstrate that the proposed emissions will not consume excessive PSD increment. The PSD increment consumption will be presented in a summary table, based on the highest second-highest concentrations for the five-year modeling period. These concentrations will be compared to the PSD Class II increments. Since the Facility is not subject to PSD review, the combined increment from other PSD sources within the study area will not be examined.

5.9 NYSDEC Cumulative Impact Assessment

The modeling study will include a cumulative impact assessment of the proposed Facility, other combustion sources on the Indian Point site (except those for emergency use that are only run for testing purposes), and the adjacent LaFarge gypsum facility (stack emissions only).

5.10 Toxic Air Pollutant Analysis

The ground level concentrations of any toxic substance that could potentially be emitted from the proposed Facility will be assessed using the methodology suggested by the NYSDOH. The assessment will be based upon modeling with the ISCST3 model and the five years of onsite meteorological data. The analysis will consider potential emissions of toxic pollutants from the Facility stacks and other existing combustion sources on the Indian Point site.

Potential toxic emissions from the turbine stacks will be based upon an analysis of the proposed facility fuel (natural gas) or emission factors from the most recent final version of AP-42. Modeling will be performed for steady-state operating conditions. Predicted short and long-term average concentrations will be compared to appropriate health-based guideline benchmarks.

If the maximum modeled annual average ground level air concentration of a non-criteria pollutant exceeds one percent of the health risk-based benchmark concentration of a persistent, bio-accumulative or toxic chemical (PBT) or ten percent of the benchmark concentration for any other chemical, the application will include an evaluation of the need to perform a multipathway risk assessment. In the event that a predicted maximum annual concentration of a PBT pollutant exceeds the one percent threshold, TRC will investigate and document the potential for existing beef or dairy farms or areas that could reasonably be expected to support such uses, to be impacted at these levels. If it can be shown that no such uses or areas exist, then the 10 percent criterion will be used to assess the potential need for a multipathway risk assessment. Should the potential need for a multipathway risk assessment be identified, Entergy will consult with the NYSDOH on the scope and approach to be used for any such study.

5.11 Visibility Impact Assessment

The relative effect the proposed Facility will have on regional visibility in the surrounding area will be assessed using the U.S. EPA VISCREEN model (Version 1.01). This model is identified and discussed in the Workbook for Plume Visual Impact Screening and Analysis, (EPA-450/4-88-015, September, 1988). The effect on visibility will be assessed using the screening procedure that involves calculation of three plume contrast coefficients using emissions of NO_2, PM/PM-10, and sulfates (i.e., H_2SO_4). The Level-1 screening procedure determines the light scattering impacts of particulates, including sulfates and nitrates, with a mean diameter of two micrometers with a standard deviation of two micrometers. The analysis will be run assuming that all emitted particulate is PM-10, which results in a conservative assessment of visibility impact.

The Level-1 screening analysis will be performed for the worst possible operating scenario. Because the proposed Facility is anticipated to have no area of impact, the visibility assessment will be performed for an observer at a distance of 30 kilometers from the Facility site with a conservative background visual range of 30 kilometers.

5.12 Construction Impacts

Potential impacts associated with the construction of the proposed Facility include emissions from engines of heavy construction equipment and fugitive dust associated with excavation, grading and traffic on unpaved roads. The applicant will provide a discussion of the expected number and type of construction equipment on site and the potential for the emissions to result in unacceptable air quality impacts. A discussion of potential fugitive dust generating activities and mitigation measures to be employed will also be provided.

5.13 Acid Deposition

The New York State Acid Deposition Control Act requires that applicants quantify a proposed facility's contribution to the New York State total deposition of sulfates and nitrates at eighteen defined receptors in New York State, New England and Canada. This analysis will performed using the procedure set forth in the March 4, 1993 memorandum from Leon Sedefian to Impact Assessment and Meteorology (IAM) staff.

5.14 Accidental Releases

Accident and risk management regulations (40 CFR Part 68, section 112r) require a subject facility to develop a risk management program (RMP). The RMP requirement is triggered for each regulated toxic and flammable substance present on-site in greater quantity than its specified regulatory threshold. Each regulated toxic substance anticipated to be present at the Facility would be accounted for and quantified with respect to its respective threshold. The only potentially hazardous substance that would be stored and used on site is aqueous ammonia (NH_3) for the SCR NO_x control system.

The Facility will be designed to use aqueous ammonia that would be stored on site. The aqueous ammonia will have a concentration of 19% or less, and, therefore, would not be considered a hazardous substance under 40 CFR Part 68, section 112r. However, the applicant will perform an analysis of the off-site consequences of an accidental release of the aqueous ammonia consistent with the methodology recommended in section 112r.

5.15 Combustion Turbine Visible Plume Analysis

A major exhaust by-product of the simple cycle turbine combustion process is water vapor. With each pound of natural gas fired, over two pounds of water vapor are formed and exhausted to the atmosphere. Since the exhaust gas contains appreciably more water vapor than the ambient air, an analysis will be performed to determine if the exhaust plume could condense and become visible under normal atmospheric conditions. A visible plume formed under such conditions is called a mixed vapor plume. When hot humid exhaust gas is vented to a cooler humid atmosphere, the combination may be at or above the saturation level and a visible plume will form. This is similar to seeing one's breath on a cold morning. Likewise, condensation trails from high altitude aircraft are formed by the same phenomenon.

5.15.1 Visible Plume Modeling Methodology

The plume visibility analysis proposed for the Facility will be performed using the exhaust conditions for two (2) General Electric 7FA combustion gas turbines operating in a simple-cycle mode exhausting to two individual stacks and will be assessed using a plume visibility model, VISPLUME, developed by TRC. VISPLUME is a post processor applied to output from the ISCST3 atmospheric dispersion model. The current version of the program will be used. Since water vapor is a non-reactive gas and is emitted at a temperature well above its dew point, the downwind dispersion characteristics can be simulated using ISCST3. The ISCST3 model will be run using the same meteorological data as the refined air quality modeling. Presently, onsite meteorology obtained at the Indian Point Nuclear Generating Station (1996-2000) is proposed for the visible plume assessment. These data also include dry bulb and dew point temperature measurements, which will be used with the VISPLUME model. All indicated calms would be set to 1 meter per second (m/s) and evaluated by the model. This is different than regulatory modeling performed to ascertain air quality impacts; however, in a plume visibility analysis, the calms are very important since the vertical plume which occurs under light wind conditions presents a high likelihood for visible plume formation. Additionally, VISPLUME collapses the wind directions to one direction and performs the visible plume calculations on a two-dimensional receptor matrix. This provides a frequency of possible visible plumes independent of wind direction. The two-dimension receptor matrix is based on downwind distance and elevation above ground. Receptors are spaced at 25-meter horizontal (downwind) and vertical intervals. In order to simulate the near-field plume rise of the exhaust plume, the transitional plume rise algorithm is used in the ISCST3 model.

The likelihood of producing a visible water plume increases with:

- Increasing ambient relative humidity;
- Increasing water vapor emission rate;
- Decreasing temperature of stack gas; and
- Decreasing ambient temperature.

In order to calculate the water vapor emission rate, the VISPLUME model considers all sources of water vapor. The primary source of water vapor is the combustion process. Additional sources of water will be added depending on the mode of operation of the turbines. The water emission rate for each mode (or operating case) will be calculated, and where applicable will include sources of water from the ambient humidity of the inlet air and any additional sources of water from the various modes of operation (e.g., inlet air fogging if applicable).

The stack exit temperature depends on the operating case and will be assessed on a case-by-case basis. The diluted plume temperature is calculated by mixing the exhaust temperature of the plume with the ambient air temperature, proportional to the amount of dilution of the plume. As the dilution ratio increases, the plume temperature approaches the ambient temperature. Note that the turbines are proposed to be simple-cycle operation with relatively high exhaust temperatures. As such, the occurrence of visible plumes is expected to be negligible or nonexistent.

A matrix of operation cases based on fuel, ambient temperature, water injection, inlet air chilling, and any other operational parameters that cause the modeling parameters to significantly change will be assessed. The operational cases will include ambient air temperature, and the modeling hours will only include those ambient temperatures that are represented by the operating case temperature. For example, if ambient temperatures of 0°F, 50°F and 100°F are selected as operating cases, the temperature range examined for the 0°F case will be based on hours with ambient temperatures below 0°F up to 25°F. Similarly, the 5°F case will be assessed by meteorological conditions with temperatures between 25°F and 75°F.

Cases where the exhaust characteristics (volume flow and temperature), and/or water emission rate vary by less than 1% will be considered sufficiently similar as to provide redundant analyses, and will be assessed as one case. The specific emission parameters have not been determined at this time; however, the analysis discussion will include a table of the water emission calculations and the emission parameters for the specific cases being assessed.

VISPLUME also uses the Sunrise/Sunset subroutine used in the U.S. EPA PCRAMMET meteorological processor to calculate the specific times for sunrise and sunset at the site location. The whole hour before the hour containing the time of sunrise, and the whole hour after the hour containing the hour of sunset is included as daylight hours. This is a very conservative estimate because it assumes the twilight periods last at least one hour, and may possibly extend to almost two hours.

In developing the VISPLUME model, TRC considered using a fixed time period for the "daylight" hours – e.g., 6 AM to 10 PM. Since the actual time of sunrise and sunset is calculated with a conservative hour or more added to account for viewing of the plume during twilight conditions, TRC believes there is no added benefit to arbitrarily assigning the daylight hours to a fixed period, (e.g., 6 AM to 10 PM), especially when the site specific times of sunrise and sunset may be calculated.

Visible plume formation is determined by comparing the hourly water vapor concentrations calculated at all downwind receptors to actual meteorological observations and the calculated saturation deficit. The saturation deficit is a measure of the amount of additional water vapor that must be added to a volume of air to bring it to saturation (i.e., 100% humidity). A visible plume is assumed to occur if the water vapor concentration exceeds the saturation deficit for each receptor location and hour modeled. Under these conditions, the water vapor will condense to form a visible plume.

Normally, the associated weather conditions (rain, snow, and fog) are identified along with time of day (day or night). Since the onsite meteorology does not identify such corresponding weather conditions, the condensed vapor plume is identified as "visible" only if it formed during the day. Note that daylight periods include the hour before sunrise and the hour after sunset as discussed previously. However, the time of day and month of all the plumes formed as well as those that occur during daylight conditions will be identified.

5.15.2 Visible Plume Analysis – Presentation of Results

The discussion of the visible plume study will provide tables of all the water emission calculations for the combustion turbines. A matrix of operation cases and modeling parameters will be presented. The modeling methodology, model description, and all assumptions provided in this protocol will be included in the analysis discussion. The visible plume modeling results will be presented as the number of total hours with calculated condensation plumes from the stack for all hours; and visible plume hours (i.e., total hours of the day and daylight hours). Graphical presentation of the worst-case (i.e., highest) number of calculated visible plumes will be included. Input and output data files will be provided for the condensation plume modeling, and included on the overall modeling data CD-ROM that will be provided with the Article X Application.

5.16 Impacts on Sensitive Population Receptors

In order to adequately assess the potential impact of the proposed Facility, a separate modeling analysis will be performed to examine the maximum impacts at areas of sensitive population groups. Specifically, such sensitive population areas include day care and nursery schools, elementary, middle, and high schools, and other community facilities where a large number of potentially air quality sensitive individuals may be resident for an appreciable amount of time. Tables will identify the maximum air quality concentrations calculated by ISCST3 that would be experienced by these locations during operation of the proposed Facility.

5.17 Demonstration Of Air Quality Compliance

The Part 201 Air Permit Application will contain a detailed summary section outlining the modeling methodology, source emissions, and presentation of modeling results. The air quality summary will include tables of maximum-modeled concentrations with locations, and distance and direction from the proposed Facility. Where applicable, figures will be provided to illustrate the locations of the maximum concentrations with contours illustrating the concentration gradients. All modeling input and output files, including the meteorological data sets, will be provided to the NYSDEC with an accompanying CD-ROM.

Table 5-1: Wind-Profile Exponents and Vertical Temperature Gradients Used in ISCST3

Stability Class	Rural Wind Profile Exponent[a]	Vertical Potential Temperature Gradient[a] (°K/m)
A	0.07	0
B	0.07	0
C	0.10	0
D	0.15	0
E	0.35	0.02
F	0.55	0.035

[a] These values represent the standard default parameters as supplied by ISCST3.

Table 5-2: Comparison of U.S. EPA and U.S. NRC Meteorological Monitoring System Equipment Specifications

Parameter	Measure	U.S. EPA Monitoring Guideline	U.S. NRC RG1.23 and ANSI 2.5
Wind Speed	Accuracy	plus/minus 0.2 m/s + 5% of value	plus/minus 0.22 m/s for < 5 mph; 10% above 5 mph
	Starting Threshold	0.5 m/s	0.45 m/s
Wind Direction	Accuracy	plus/minus 5 degrees	plus/minus 5 degrees
	Starting Threshold	0.5 m/s	0.45 m/s
	Damping Rate	0.4-0.7	0.4-0.6
	Delay Distance @ 10 degrees	5 m	2 m
Temperature	Accuracy	plus/minus 0.5 degrees C	plus/minus 0.5 degrees C
Delta-T	Accuracy	plus/minus 0.1 degrees C	plus/minus 0.15 degrees C/50 m
Data Recovery	Joint Recovery of Wind Direction and Speed and Delta-T	90%	90%

Table 5-3: Background Concentrations of Criteria Pollutants[a]

Pollutant	Averaging Period	1998 Background Concentration ($\mu g/m^3$)	1999 Background Concentration ($\mu g/m^3$)	2000 Background Concentration ($\mu g/m^3$)	Monitor Location
CO	1-Hour	5,290	6,555	**6,900**	New York City, Bronx County, EPA AIRData ID #360050083-1
	8-Hour	3,680	**4,600**	4,025	
SO_2	3-Hour	58	66	63	Mt. Ninham, Putnam County, EPA AIRData ID #360790005-1
	24-Hour	37	26	**39**	
	Annual	**5**	**5**	**5**	
PM-10	24-Hour	**55**	45	49	New York City, New York County, EPA AIRData ID #360610010-1
	Annual	**25**	21	22	
NO_2	Annual	**56**	55	55	New York City, Bronx County, EPA AIRData ID #360050083-1

[a] Highest second-highest short-term (1-, 3-, 8-, & 24-hour) and maximum annual average concentrations presented.
Maximum value over the three-year period identified in bold type.

6.0 REFERENCES

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APPENDIX A

LAND USE CLASSIFICATION ANALYSIS

APPENDIX A
LAND USE CLASSIFICATION ANALYSIS

The Auer method identifies the amount of land covered by structures and pavement versus the amount of land covered by grass or vegetation within a 3-kilometer radius around the proposed site. The Auer land use types are provided below in Table A-1 below.

Table A-1: Auer Land Use Types

Urban Land Use Types	Rural Land Use Types
Industrial (I1)	Common Residential (R1)
Light Industrial (I2)	Metropolitan Natural (A1)
Commercial (C1)	Water Surfaces (A5)
Compact Residential (R2)	
Compact Residential (R3)	

The Auer method, in agreement with the U.S. EPA, defines an urban area as an area whose land usage within the 3-kilometer radial study area is more than 50% urban; otherwise, Auer defines the area as rural.

Figure A-1 depicts the 3-kilometer radial study area surrounding the site. For this study area, the land use types were identified according to the land use types defined in Table A-1 above. After the land use types were identified, their respective percent areas were estimated. The land use types identified within the 3-kilometer radial study area along with their respective percent areas are provided in Table A-2.

Table A-2: Percent Area Land Use

Urban	Percent	Rural	Percent
Industrial (I1), Light Industrial (I2)	9%	Common Residential (R1)	3%
Commercial (C1)	3%	Metropolitan Natural (A1)	29%
Compact Residential (R2/R3)	21%	Water Surfaces (A5)	35%
Total Urban	33%	**Total Rural**	67%

Approximately 35% of the area surrounding the facility is water (A5 according to the Auer classification technique). Water surfaces are considered rural along with metropolitan natural (A1) and common residential (R1), which make up 29% and 3%, respectively of the land use within 3 kilometers of the proposed site. Thus a total of 67% of the land use surrounding the proposed Facility is classified as rural. Therefore, the rural dispersion coefficients will be used for the air quality modeling analysis.

APPENDIX D

RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS

TABLE D-1
Recent BACT/LAER Determinations for Simple Cycle Combustion Turbines
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	PROCESS	THROUGHPUT (MW)	NOx LIMIT (ppm)	CONTROL DESCRIPTION
CARSON ENERGY GROUP & CENTRAL VALLEY FIN AUTY	ELK GROVE, CA	7/23/1993	TURBINE, GAS, SIMPLE CYCLE, GE LM6000	132	5.0	SELECTIVE CATAYLTIC REDUCTION, WATER INJECTION
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO, CA	8/19/1994	TURBINE, SIMPLE CYCLE LM6000 GAS	123.5	5.0	SELECTIVE CATALYTIC REDUCTION, WATER INJECTION
DUKE ENERGY KNOX LLC	WHEATLAND, IN	5/29/2001	TURBINE, NATURAL GAS, SIMPLE CYCLE	339	9.0	DRY LOW NOX BURNERS, LB/H LIMIT FOR EACH CT.
MIRANT SUGAR CREEK, LLC	W. TERRE HAUTE, IN	5/9/2001	TURBINE, NATURAL GAS, SIMPLE CYCLE, FOUR	170	9.0	GOOD COMBUSTION, LB/H LIMIT FOR EACH CT.
ODEC	ROCK SPRINGS, MD	10/30/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	1,020	9.0	DRY LOW-NOX BURNERS
SOUTH EASTERN ENERGY CORP.	ALABAMA	1/2001	TURBINE, NATURAL GAS, SIMPLE CYCLE	1,500	9.0	DRY LOW-NOX BURNERS
DUKE ENERGY	ALEXANDER CITY, AL	2/2001	TURBINE, NATURAL GAS, SIMPLE CYCLE	1,260	9.0	DRY LOW-NOX BURNERS
BROAD RIVER ENERGY	SOUTH CAROLINA	12/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	342	9.0	DRY LOW-NOX BURNERS
DES PLAINES GREEN LAND	ILLINOIS	09/28/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	664	9.0	DRY LOW-NOX BURNERS
MCHENRY COUNTY PLANT	ILLINOIS	12/09/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	510	9.0	DRY LOW-NOX BURNERS
KENDALL NEW CENTURY	ILLINOIS	01/14/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	664	9.0	DRY LOW-NOX BURNERS
KANSAS CITY POWER & LIGHT HAWTHORNE	MISSOURI	08/18/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	150	9.0	DRY LOW-NOX BURNERS
PLATTE RIVER POWER AUTHORITY	COLORADO	12/0000	TURBINE, NATURAL GAS, SIMPLE CYCLE	82	9.0	DRY LOW-NOX BURNERS
PUBLIC SERVICE OF COLORADO-FT. ST. VRAIN	COLORADO	06/19/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	240	9.0	DRY LOW-NOX BURNERS
DUKE ENERGY - AUDRAIN GENERATING STATION	VANDALIA, MO	5/9/2000	TURBINES, SIMPLE CYCLE, GAS (8)	80	12.0	DRY LOW-NOX BURNERS, GOOD COMBUSTION
DUKE ENERGY LAKE	FLORIDA	07/18/2001	TURBINE, NATURAL GAS, SIMPLE CYCLE	640	12.0	SELECTIVE CATALYTIC REDUCTION, WATER INJECTION
CP&L LEE PLANT	WAYNE CO. NC	07/01/1998	TURBINE, NATURAL GAS, SIMPLE CYCLE	680	12.0	SELECTIVE CATALYTIC REDUCTION, WATER INJECTION
DUKE-BOLLINGER	MISSOURI	09/22/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	640	12.0	DRY LOW-NOX BURNERS
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	4/11/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74	15.0	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS
WESTPLAINS ENERGY	PUEBLO, CO	6/14/1996	SIMPLE CYCLE TURBINE, NATURAL GAS	218.5	15.0	DRY LOW NOX COMBUSTION SYSTEM. COMMITMENT TO UPGRADE THE DLN
RENAISSANCE POWER LLC	CARSON CITY, MI	6/7/2001	STATIONARY GAS TURBINES, SIMPLE CYCLE 4 EACH	170	15.0	DRY LOW NOX BURNERS. LIMITS DO NOT APPLY DURING STARTUP SHUTDOWN.
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN, GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	960	15.0	
PALMETTO POWER	FLORIDA	6/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	540	15.0	DRY LOW-NOX BURNERS
HEARD COUNTY POWER	GEORGIA	10/01/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	510	15.0	DRY LOW-NOX BURNERS
ROCK ROAD POWER	ILLINOIS	10/27/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	121	15.0	DRY LOW-NOX BURNERS
INDECK LIBERTYVILLE	ILLINOIS	02/25/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	300	15.0	DRY LOW-NOX BURNERS
FULTON COGENERATION-MANCHIEF	COLORADO	8/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	284	15.0	DRY LOW-NOX BURNERS
ALABAMA POWER CO. - GREENE COUNTY	BIRMINGHAM, AL	5/26/1993	SIMPLE CYCLE COMBUSTION TURBINES, 9, 80 MW	80	25.0	WATER INJECTION.
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN, CO	6/30/1998	SIMPLE CYCLE TURBINE, NATURAL GAS	329	25.0	DRY LOW NOX COMBUSTION
LINCOLN ELECTRIC SYSTEM	LINCOLN, NE	11/22/1999	TURBINE, GAS-FIRED SIMPLE CYCLE	298	25.0	ANNUAL OPERATING HRS. LIMITED. ANNUAL FUEL USE LIMITS. DRY LOW NOX.
PSEG FOSSIL LLC	BURLINGTON, NJ	05/07/2000	TURBINE, NATURAL GAS, SIMPLE CYCLE	170	25.0	WATER INJECTION.
PSI - FAYETTE PEAKING STATION	INDIANA	12/18/1998	TURBINE, NATURAL GAS, SIMPLE CYCLE	520	25.0	EITHER DRY LOW NOX or WATER INJECTION
INDIANAPOLIS POWER AND LIGHT	INDIANA	09/17/1999	TURBINE, NATURAL GAS, SIMPLE CYCLE	265	25.0	DRY LOW-NOX BURNERS
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN, GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE	960	42.0	

Table D-2
Recent BACT/LAER Determinations for Gas-Fired External Combustion Engines <50mmBtu/hr
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	PROCESS	THROUGHPUT (mmBtu/hr)	NOx LIMIT (lb/mmBtu)	CONTROL DESCRIPTION
NUCOR STEEL	CRAWFORDSVILLE, IN	11/30/1993	BOILER, PICKLE LINE PACKAGE, 3 EA	7.3	0.0073	
DISNEYLAND RESORT	ANAHEIM, CA	9/27/2001	BOILER, CLEAVER BROOKS WATER-TUBE	8.5	0.0150	LOW NOX BURNER
KALAMAZOO POWER LIMITED	COMSTOCK, MI	12/3/1991	BOILER, BACK-UP, GAS-FIRED, W/ EMER GEN.	5.0	0.0200	
ANNISTON ARMY DEPOT	ANNISTON, AL	6/19/1997	BOILER, NATURAL GAS FIRED, 2	11.7	0.0300	CLEAN FUEL, LOW NOX BURNERS
STAFFORD RAILSTEEL CORPORATION	WEST MEMPHIS, AR	8/17/1993	BOILER, VTD	46.5	0.0349	FUEL SPEC: USE OF NATURAL GAS & LOW NOX BURNERS
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	(3) UTILITY BOILER (EP #S 00002-4)	33.0	0.0350	INDUCED FLUE GAS RECIRCULATION (FGR)
SUNLAND REFINERY	BAKERSFIELD, CA	9/24/1992	BOILERS (2)	12.6	0.0360	FGR/LOW NOX BURNER
DOCTORS MEDICAL CENTER	MODESTO, CA	1/5/1998	BOILER, NAT GAS FIRED, WITH LOW SULFUR #2 OIL BACK	3.8	0.0400	INDUSTRIAL COMBUSTION BURNER AS FGR
MIRANT SUGAR CREEK, LLC	WEST TERRA HAUTE, IN	5/9/2001	AUXILIARY BOILER	35	0.0490	LOW NOX BURNERS
DUKE ENERGY, VIGO LLC	WEST TERRA HAUTE, IN	6/6/2001	AUXILIARY BOILER	46	0.0490	GOOD COMBUSTION, LOW NOX BURNER
CHAMPION INTERNATIONAL	COURTLAND, AL	5/8/1991	BOILER, NAT. GAS FIRED	5.8	0.0500	FLUE GAS RECIRCULATION
DEL MONTE FOODS, USA	CALIFORNIA	9/26/1990	BOILER, JOHNSTON (NATURAL GAS)	20.9	0.0500	BURNER, JOHNSTON
HULS AMERICA	THEODORE, AL	8/31/1990	BOILERS, NATURAL GAS, 2	38.9	0.0750	LOW NOX BURNERS
SHELL OFFSHORE, INC.	CODEN, AL	10/25/1989	BOILER, GAS FIRED	48.2	0.0996	LOW NOX BURNERS
NATURALGAS PIPELINE CO	GENESEO, IL	3/1/1989	BOILER, NAT GAS FIRED	8.4	0.1000	
LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	4 MILES E-NE OF LYSITE, WY	4/3/1998	BOILER, AUXILIARY, NATURAL GAS	22.9	0.1005	
O.H. KRUSE GRAIN AND MILLING	PIXLEY, CA	9/19/1996	300 HP BOILER USED AS A BACKUP	10.0	0.1060	NO CONTROL
LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	LOST CABIN, WY	8/12/1991	BOILER, AUXILIARY, NATURAL GAS FIRED, 2 EACH	2.8	0.1064	
TRANSAMERICAN REFINING CORPORATION (TARC)	NEW SARPY, LA	1/15/1993	BOILER	8.2	0.1167	GOOD COMBUSTION PRACTICES
CNG TRANSMISSION CORPORATION	WEST VIRGINIA	5/3/1993	BOILER, WATER	10.0	0.1400	
NUCOR STEEL	CRAWFORDSVILLE, IN	11/30/1993	BOILER, VACUUM DEGASSER	34.0	0.2000	LOW NOX BURNER, STAGED COMBUSTION
SITIX OF PHOENIX, INC.	PHOENIX, AZ	2/1/1996	BOILER, GAS-FIRED	42.0	0.2664	FLUE GAS RECIRCULATION (FGR) NOX NOT TO EXCEED 30 PPM
KAMINE/BESICORP CORNING L.P.	SOUTH CORNING, NY	11/5/1992	BOILERS, AUXILIARY (3)	33.5	0.3200	LOW NOX BURNER, FGR
LUNA ENERGY FACILITY	DEMING, NM	12/29/2000	AUXILIARY BOILER	44	0.4850	SCR
JVC MAGNETICS AMERICA CO.	TUSCALOOSA, AL	6/16/1994	BOILER, NATURAL GAS	5.2	1.7562	FUEL SPEC. NATURAL GAS W/ MAX 0.5% SULFUR FUEL OIL AS BACKUP

APPENDIX E

DRAFT NO_X BUDGET AND ACID RAIN PERMIT APPLICATION FORMS (FOR INFORMATIONAL PURPOSES)

NOx Budget Permit Application DRAFT

For more information, refer to 6 NYCRR Part 204-3.3

This submission is: ☒ New ☐ Revised

Has your Title V permit been modified to include 6 NYCRR Part 204? ☐ Yes ☐ No ... I will notify the regional DEC office that my Title V permit must be modified in order to include 6 NYCRR Part 204.
☒ Not Applicable (New Facility)

Have you addressed the issues outlined in the 6/25/01 letter mailed to all AAR's? ☐ Yes ☐ No ... I will ensure that these requirement are addressed and approved by the DEC prior to May 1, 2002.
☒ Not Applicable (New Facility)

STEP 1
Identify the source by plant name, State, and ORIS or facility code

Plant Name	State	ORIS/Facility Code
Indian Point Peaking Facility	NY	

Code

STEP 2
Enter the unit ID# for each NOx budget unit

Unit ID#

0001					
0002					

STEP 3
Read the standard requirements and the certification, enter the name of the NOx authorized account representative, and sign and date

Standard Requirements

(a) Permit Requirements

(1) The NOx authorized account representative of each NOx Budget unit shall:
(i) Submit to the Department a complete NOx Budget permit application under Section 204-3.3 in accordance with the deadlines specified in Subdivision 204-3.2(b);
(ii) Submit in a timely manner any supplemental information that the Department determines is necessary in order to review a NOx Budget permit application and issue or deny a NOx Budget permit.
(2) The owners and operators of each NOx Budget unit shall have a NOx Budget permit and operate the unit in compliance with such NOx Budget permit.

(b) Monitoring requirements

(1) The owners and operators and, to the extent applicable, the NOx authorized account representative of each NOx Budget source and each NOx Budget unit at the source shall comply with the monitoring requirements of Subpart 204-8.
(2) The emissions measurements recorded and reported in accordance with Subpart 204-8 shall be used to determine compliance by the unit with the NOx Budget emissions limitation under subdivision (c) of this section.

(c) Nitrogen oxides requirements

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(1) The owners and operators of each NOx Budget source and each NOx Budget unit at the source shall hold NOx allowances available for compliance deductions under Section 204-6.5, as of the NOx allowance transfer deadline, in the unit's compliance account and the source's overdraft account in an amount not less than the total NOx emissions for the control period from the unit, as determined in accordance with Subpart 204-8.
(2) Each ton of nitrogen oxides emitted in excess of the NOx Budget emissions limitation shall constitute a separate violation of this Part, the Clean Air Act and applicable State law.
(3) A NOx Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2003 or the date on which the unit commences operation.
(4) NOx allowances shall be held in, deducted from, or transferred among NOx Allowance Tracking System accounts in accordance with Subparts 204-5, 204-6, 204-7, and 204-9.
(5) A NOx allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) of this section, for a control period in a year prior to the year for which the NOx allowance was allocated.
(6) A NOx allowance allocated by the Department under the NOx Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the NOx Budget Trading Program. No provision of the NOx Budget Trading Program, the NOx Budget permit application, or the NOx Budget permit and no provision of law shall be construed to limit the authority of the United States or the State to terminate or limit such authorization.
(7) A NOx allowance allocated by the Department under the NOx Budget Trading Program does not constitute a property right.

(d) Excess emissions requirements

The owners and operators of a NOx Budget unit that has excess emissions in any control period shall:
(1) Forfeit the NOx allowances required for deduction under Paragraph 204-6.5(d)(1); and
(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed under Paragraph 204-6.5(d)(3).

(e) Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the NOx Budget source and each NOx Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Department or the Administrator.

(i) The account certificate of representation for the NOx authorized account representative for the source and each NOx Budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with Section 204-2.4; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new account certificate of representation changing the NOx authorized account representative.
(ii) All emissions monitoring information, in accordance with Subpart 204-8; provided that to the extent that Subpart 204-8 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NOx Budget Trading Program.
(iv) Copies of all documents used to complete a NOx Budget permit application and any other submission under the NOx Budget Trading Program or to demonstrate compliance with the requirements of the NOx Budget Trading Program.

(2) The NOx authorized account representative of a NOx Budget source and each NOx Budget unit at the source shall submit the reports and compliance certifications required under the NOx Budget Trading Program, including those under Subparts 204-4, 204-8, or 204-9.

(f) Liability

(1) No permit revision shall excuse any violation of the requirements of the NOx Budget Trading Program that occurs prior to the date that the revision takes effect.
(2) Any provision of the NOx Budget Trading Program that applies to a NOx Budget source (including a provision applicable to the NOx authorized account representative of a NOx Budget source) shall also apply to the owners and operators of such source and of the NOx

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Budget units at the source.

(3) Any provision of the NOx Budget Trading Program that applies to a NOx Budget unit (including a provision applicable to the NOx authorized account representative of a NOx budget unit) shall also apply to the owners and operators of such unit. Except with regard to the requirements applicable to units with a common stack under Subpart 204-8, the owners and operators and the NOx authorized account representative of one NOx Budget unit shall not be liable for any violation by any other NOx Budget unit of which they are not owners or operators or the NOx authorized account representative and that is located at a source of which they are not owners or operators or the NOx authorized account representative.

(g) Effect on Other Authorities

No provision of the NOx Budget Trading Program, a NOx Budget permit application, or a NOx Budget permit, shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NOx authorized account representative of a NOx Budget source or NOx Budget unit from compliance with any other provisions of applicable State and federal law and regulations.

Certification

I am authorized to make this submission on behalf of the owners and operators of the NOx Budget sources or NOx Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Michael R. Kansler
Signature	
Date	
Company	Entergy Indian Point Peaking Facility, LLC
Street	440 Hamilton Avenue
City/State/Zip	White Plains, NY 10601
Phone	(914) 272 - 3200
Fax	(914) 272 - 3205
E-Mail	mkansle@entergy.com

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STEP 4 (For sources with opt-in units only) **For each unit listed under Step 2 that is an opt-in unit, re-enter the unit ID#, and indicate if this is an initial permit application for that unit by checking the box**

Unit ID#	Check box if initial application
Not Applicable (N/A)	☐
N/A	☐
N/A	☐
N/A	☐

Step 5 (For sources with opt-in units only) **Read the certification, enter the name of the NOx authorized account representative, sign and date**

I certify that each unit for which this permit application is submitted under subpart 9 of 6 NYCRR Part 204 is not a NOx Budget unit under 6 NYCRR 204-1.4(a) and is not covered by an exemption under 6 NYCRR 204-1.4(b) that is in effect.

Name	N/A
Signature	N/A
Date	N/A

STEP 6 (For sources submitting an initial NOx Budget opt-in permit application) **Read the certification, enter the name of the NOx authorized account representative, sign and date**

I certify that each unit for which this permit application is submitted under subpart 9 of 6 NYCRR Part 204 is operating, as that term is defined under 6 NYCRR 204-1.2.

Name	N/A
Signature	N/A
Date	N/A

SUBMISSION INSTRUCTIONS:

One copy must be sent to the DEC regional office where your facility is located.

One copy must be sent to the DEC Central Office at:

New York State Department of Environmental Conservation
Attn: Robert D. Bielawa, P.E.
625 Broadway, 2nd Floor
Albany, NY 12233-3251

Please call Mr. Bielawa at 518.402.8396 with any questions.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

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Acid Rain Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31

This submission is: ☒ New ☐ Revised

STEP 1

Identify the source by plant name, State, and ORIS code.

Plant Name **Indian Point Peaking Facility** State **NY** ORIS Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a." For new units, enter the requested information in columns "c" and "d."

a	b	c	d
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	New Units Commence Operation Date	New Units Monitor Certification Deadline
0001	**Yes**	**Approximately June 1, 2004**	**90 Days after (c)**
0002	**Yes**	**Approximately June 1, 2004**	**90 Days after (c)**

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STEP 3

Read the standard requirements

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another affected unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

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Excess Emissions Requirements

STEP 3, Cont'd.

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

Plant Name (from Step 1) **Indian Point Peaking Facility**

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Step 3, Cont'd.

Liability, Cont'd.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4

Read the certification statement, sign, and date

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **Michael R. Kansler**	
Signature	Date

United States
Environmental Protection Agency
Acid Rain Program

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OMB No. 2060-0258

EPA

Certificate of Representation

Page 1

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☒ New ☐ Revised (revised submissions must be complete; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 ☒

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name Indian Point Peaking Facility	State NY	ORIS Code

STEP 2
Enter requested information for the designated representative.

Name Michael R. Kansler	
Address Entergy Indian Point Peaking Facility, LLC 40 Hamilton Avenue White Plains, NY 10601	
Phone Number (914) 272 - 3200	Fax Number (914) 272 - 3205
E-mail address (if available) mkansle@entergy.com	

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name Not Applicable (N/A)	
Phone Number	Fax Number
E-mail address (if available)	

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

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Plant Name (from Step 1) **Indian Point Peaking Facility**

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date
Signature (alternate designated representative) **N/A**	Date

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name **Entergy Indian Point Peaking Facility, LLC**					☒ Owner	☒ Operator
ID# **0001**	ID#	ID#	ID#	ID#	ID#	ID#
ID# **0002**	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

APPENDIX F

TURBINE LOAD ANALYSIS RESULTS

Table F-1
Indian Point Peaking Facility
Maximum Modeled Concentrations (ug/m^3)

Entergy Indian Point Peaking Facility, LLC: 2 GE 7FA Simple Cycle Combustion Turbines - Gas Only

1-Hour	XOQ	yymmddhh	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO_x	CO	PM-10	SO_2	Distance (m)	Direction (deg)
CASE01	7.65087	101002	584,932	4,570,538	303.7	25.7	10.6	22.0	2.7	3,300	310
CASE02	8.62212	101002	584,932	4,570,538	303.7	23.6	9.7	23.9	2.4	3,300	310
CASE03	9.58032	99010521	584,949	4,569,867	271.7	22.3	9.2	25.6	2.1	2,900	300
CASE04	7.8258	101002	584,932	4,570,538	303.7	25.3	10.4	22.1	2.5	3,300	310
CASE05	8.70853	101002	584,932	4,570,538	303.7	23.3	9.6	23.8	2.3	3,300	310
CASE06	9.58032	99010521	584,949	4,569,867	271.7	22.1	9.1	25.4	2.0	2,900	300
CASE07	8.02476	101002	584,932	4,570,538	303.7	23.9	9.9	22.3	2.3	3,300	310
CASE08	8.13587	101002	584,932	4,570,538	303.7	23.9	9.8	22.5	2.3	3,300	310
CASE09	8.79375	101002	584,932	4,570,538	303.7	22.3	9.1	23.7	2.0	3,300	310
CASE10	9.86656	99010521	584,949	4,569,867	271.7	21.2	8.7	25.9	1.8	2,900	300
3-Hour	**XOQ**	**yymmddhh**	**UTM Easting (m)**	**UTM Northing (m)**	**Elevation (m)**	**NO_x**	**CO**	**PM-10**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE01	7.34765	96073103	584,932	4,570,538	303.7	24.7	10.1	21.1	2.6	3,300	310
CASE02	8.2016	96073103	584,932	4,570,538	303.7	22.5	9.3	22.7	2.3	3,300	310
CASE03	9.20355	96073103	585,238	4,570,281	272.5	21.4	8.8	24.6	2.0	2,900	310
CASE04	7.50439	96073103	584,932	4,570,538	303.7	24.2	10.0	21.2	2.4	3,300	310
CASE05	8.26293	96073103	584,932	4,570,538	303.7	22.1	9.1	22.6	2.1	3,300	310
CASE06	9.20355	96073103	585,238	4,570,281	272.5	21.3	8.7	24.4	1.9	2,900	310
CASE07	7.68133	96073103	584,932	4,570,538	303.7	22.9	9.4	21.4	2.2	3,300	310
CASE08	7.77946	96073103	584,932	4,570,538	303.7	22.9	9.4	21.5	2.2	3,300	310
CASE09	8.37779	96073103	585,238	4,570,281	272.5	21.3	8.7	22.5	1.9	2,900	310
CASE10	9.46614	96073103	585,238	4,570,281	272.5	20.4	8.3	24.8	1.7	2,900	310
8-Hour	**XOQ**	**yymmddhh**	**UTM Easting (m)**	**UTM Northing (m)**	**Elevation (m)**	**NO_x**	**CO**	**PM-10**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE01	3.67383	96073108	584,932	4,570,538	303.7	12.3	5.1	10.5	1.3	3,300	310
CASE02	4.26716	96092708	586,110	4,570,755	243.3	11.7	4.8	11.8	1.2	2,700	330
CASE03	4.99512	96092708	586,110	4,570,755	243.3	11.6	4.8	13.3	1.1	2,700	330
CASE04	3.7522	96073108	584,932	4,570,538	303.7	12.1	5.0	10.6	1.2	3,300	310
CASE05	4.35238	96092708	586,110	4,570,755	243.3	11.7	4.8	11.9	1.1	2,700	330
CASE06	4.99512	96092708	586,110	4,570,755	243.3	11.5	4.7	13.2	1.0	2,700	330
CASE07	3.84066	96073108	584,932	4,570,538	303.7	11.4	4.7	10.7	1.1	3,300	310
CASE08	3.88973	96073108	584,932	4,570,538	303.7	11.4	4.7	10.7	1.1	3,300	310
CASE09	4.44005	96092708	586,110	4,570,755	243.3	11.3	4.6	11.9	1.0	2,700	330
CASE10	5.18232	96092708	586,110	4,570,755	243.3	11.1	4.6	13.6	0.9	2,700	330
24-Hour	**XOQ**	**yymmddhh**	**UTM Easting (m)**	**UTM Northing (m)**	**Elevation (m)**	**NO_x**	**CO**	**PM-10**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE01	1.22461	96073124	584,932	4,570,538	303.7	4.1	1.7	3.51	0.43	3,300	310
CASE02	1.36693	96073124	584,932	4,570,538	303.7	3.7	1.5	3.79	0.38	3,300	310
CASE03	1.53393	96073124	585,238	4,570,281	272.5	3.6	1.5	4.10	0.34	2,900	310
CASE04	1.25073	96073124	584,932	4,570,538	303.7	4.0	1.7	3.53	0.40	3,300	310
CASE05	1.37715	96073124	584,932	4,570,538	303.7	3.7	1.5	3.76	0.36	3,300	310
CASE06	1.53393	96073124	585,238	4,570,281	272.5	3.5	1.5	4.06	0.32	2,900	310
CASE07	1.28022	96073124	584,932	4,570,538	303.7	3.8	1.6	3.56	0.37	3,300	310
CASE08	1.29658	96073124	584,932	4,570,538	303.7	3.8	1.6	3.58	0.36	3,300	310
CASE09	1.3963	96073124	585,238	4,570,281	272.5	3.5	1.5	3.76	0.32	2,900	310
CASE10	1.57769	96073124	585,238	4,570,281	272.5	3.4	1.4	4.13	0.28	2,900	310
Annual	**XOQ**	**Year**	**UTM Easting (m)**	**UTM Northing (m)**	**Elevation (m)**	**NO_x**	**CO**	**PM-10**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE01	0.0403	1998	586,537	4,570,954	210.4	0.135	0.056	0.116	0.0141	2,700	340
CASE02	0.05156	1998	586,537	4,570,954	210.4	0.141	0.058	0.143	0.0144	2,700	340
CASE03	0.0632	1998	586,537	4,570,954	210.4	0.147	0.061	0.169	0.0139	2,700	340
CASE04	0.042	1998	586,537	4,570,954	210.4	0.136	0.056	0.118	0.0134	2,700	340
CASE05	0.05288	1998	586,537	4,570,954	210.4	0.142	0.058	0.144	0.0137	2,700	340
CASE06	0.0632	1998	586,537	4,570,954	210.4	0.146	0.060	0.167	0.0133	2,700	340
CASE07	0.04407	1998	586,537	4,570,954	210.4	0.131	0.054	0.123	0.0128	2,700	340
CASE08	0.04529	1998	586,537	4,570,954	210.4	0.133	0.055	0.125	0.0127	2,700	340
CASE09	0.05421	1998	586,537	4,570,954	210.4	0.138	0.056	0.146	0.0125	2,700	340
CASE10	0.06643	1998	586,537	4,570,954	210.4	0.143	0.058	0.174	0.012	2,700	340

APPENDIX G

MODELING INPUT & OUTPUT FILES (ON CD-ROM)

(Not included in all copies)