CPV Valley Energy Center
Wawayanda, New York

630 MW Combined Cycle Facility
PSD and Part 201 Air Permit Application

November 2008

Submitted to:

U.S. Environmental Protection Agency
Region 2
290 Broadway
New York, New York 10007

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LIST OF ACRONYMS

Acronym	Definition
AAR	Authorized Account Representative
ACC	air-cooled condenser
ACT	Alternative Control Techniques
AGC	Annual Guideline Concentration
AGL	above grade level
AP-42	Compilation of Air Pollutant Emission Factors, Fifth Edition
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
BHP	Brake Horsepower
BPIPPRM	Building Profile Input Program for PRIME (version 24274)
Btu	British thermal unit
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CEM	continuous emissions monitoring
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CHP	combined heat and power, or cogeneration
CO	carbon monoxide
CO_2	carbon dioxide
COC	Community of Concern
CT	Combustion turbine
CTG	combustion turbine generator
DB	duct burner
DEM	Digital Elevation Model
DLN	dry low-NO_x
EIS	Environmental Impact Statement
EJ	Environmental Justice
ERCs	emission reduction credits
ESA	Endangered Species Act
F	fluoride

Acronym	Definition
FGD	Flue Gas Desulfurization
FGR	flue gas recirculation
FLAG	Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report - Revised
FWS	Fish and Wildlife Service
ft	feet
GEP	good engineering practice
H_2O	water
H_2SO_4	sulfuric acid
HAP	Hazardous Air Pollutant
HHV	higher heating value
HRSG	heat recovery steam generator
K	degrees on the Kelvin scale
km	kilometer
LAER	Lowest Achievable Emission Rate
lb/hr	pounds per hour
lb/mmBtu	pounds per million British thermal units
LNB	low-NO_x burner
$\mu g/m^3$	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
MSA	Metropolitan Statistical Area
MSL	mean sea level
MW	megawatt
N_2	nitrogen
NAAQS	National Ambient Air Quality Standards
NAD 83	North American Datum 1983
NCDC	National Climatic Data Center
NEPA	National Environmental Policy Act
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia

Acronym	Definition
$(NH_4)_2SO_4$	ammonium sulfate
NH_4HSO_4	ammonium bisulfate
NLCD92	National Land Cover Data 1992
NMHC	Non-methane hydrocarbon
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NNSR	Non-Attainment New Source Review
NSPS	New Source Performance Standards
NNSR	Non-Attainment New Source Review
NSR	New Source Review
NWA	National Wilderness Area
NWR	National Wildlife Refuge
NWS	National Weather Service
NYAAQS	New York Ambient Air Quality Standards
NYCRR	New York Code of Rules and Regulations
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
NYSDOH	New York State Department of Health
NYSDOT	New York State Department of Transportation
NYSDPS	New York State Department of Public Service
O_2	oxygen
O_3	ozone
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
Pb	lead
PM	particulate matter
PM-2.5	Particulate matter with an aerodynamic diameter of 2.5 microns or less
PM-10	particulate matter with an aerodynamic diameter of 10 microns or less

Acronym	Definition
ppm	parts per million
ppmvd	parts per million dry volume
PSD	Prevention of Significant Deterioration of Air Quality
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RGGI	Regional Greenhouse Gas Initiative
scf	standard cubic feet
SCR	Selective Catalytic Reduction
SEQRA	State Environmental Quality Review Act
SGC	Short-term Guideline Concentration
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
STG	steam turbine generator
tpy	tons per year
TRI	Toxic Release Inventory
TSP	total suspended particulate
ULSD	Ultra low sulfur diesel
USEPA	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

CPV Valley, LLC is proposing to construct and operate a nominal 630-megawatt (MW) combined cycle electric generating facility known as the CPV Valley Energy Center (the Project or the Facility) located in the Town of Wawayanda, Orange County, New York. This application only addresses the air quality analyses required by the New York State Department of Environmental Conservation (NYSDEC) and US Environmental Protection Agency (USEPA) for air permitting purposes. Other multidisciplinary studies of the Project's impact on environmental and community resources will be presented in an Environmental Impact Statement (EIS) prepared pursuant to the State Environmental Quality Review Act (SEQRA).

The Facility will be located within an approximately 21.25-acre site located within a larger 122-acre parcel of undeveloped land. The CPV Valley Energy Center will include two F-Class combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs) equipped with natural gas-fired duct burners for supplementary firing and a single stream turbine generator (STG) with an air-cooled condenser (ACC). CTG/HRSG exhaust gases will be directed into two stacks (one for each CTG/HRSG). Supporting auxiliary equipment includes a natural gas fired auxiliary boiler, two small dew point fuel gas heaters (fuel gas heaters), an emergency diesel generator, and an emergency diesel fire pump.

The proposed CTGs will be fueled primarily by natural gas with ultra low sulfur diesel (ULSD) proposed as backup fuel to be used for up to the equivalent of 720 hours per year per CTG. The duct burners will fire natural gas exclusively and will only operate when the CTGs are firing natural gas. The CTGs will utilize a dry low-NO_x (DLN) combustor for gas firing and water injection for control of nitrogen oxides (NO_x) when firing ULSD. A selective catalytic reduction (SCR) system will be used to further control NO_x emissions. An oxidation catalyst will be located in the HRSG upstream of the SCR and used to control emissions of carbon monoxide (CO) as well as volatile organic compounds (VOC). Upon leaving the SCR, turbine exhaust gases will be directed to two stacks at 275 feet above grade with an inner exit flue diameter of 19 feet. In addition, CTG inlet air will be cooled using an evaporative cooler when ambient temperatures are high, to improve CTG efficiency and increase CTG generation output.

The Project will be designed to operate on a continuous basis, but may operate at partial loads when it is dispatched. Partial loads can be achieved by operating the turbine at less than its full capacity. However, part-load turbine operation will be limited to between 60 to 100% of turbine load for natural gas firing and between 70 to 100% for ULSD firing.

The Facility is located at approximately 41.413 North Latitude, 74.435 West Longitude. The Facility is scheduled to begin producing power by the summer of 2012. Construction will take approximately twenty-four months and is planned to start in the 1st quarter of 2010 (following receipt of all necessary local and environmental approvals).

1.2 Application Summary

The proposed Facility is considered a new major stationary source, and as such is subject to the Prevention of Significant Deterioration (PSD) regulations. The Facility will be located in an area that is classified as non-attainment for ozone and PM-2.5, and potential emissions exceed 100 tons per year (tpy) for NO_x and 50 tpy for VOC. Therefore, the Project is also subject to 6 NYCRR Part 231-2 Non-Attainment New Source Review (NNSR) for emissions of NO_x and VOC, which are precursors to ozone. Potential emissions of PM-2.5 will be limited to 95 tpy by an enforceable permit limit. This level is below the associated 100 tpy major source threshold for NNSR for PM-2.5, and therefore the Project will not be subject to NNSR review for PM-2.5.

PSD review requirements include (for each pollutant having potential emissions greater than PSD significant emission rates):

- Best Available Control Technology (BACT) analysis;
- Air quality impacts analysis; and
- Additional impacts analysis.

Non-Attainment NSR requirements include:

- Lowest Achievable Emission Rate (LAER) analysis;
- Emission offsets; and
- Alternatives analysis.

In addition to addressing the PSD and NSR requirements, this application demonstrates that the proposed Facility will comply with all other applicable federal and state air quality requirements, including but not limited to:

- Federal New Source Performance Standards (NSPS) for the combustion turbines, duct burners, auxiliary boiler and internal combustion engines
- CAA Title IV (Acid Rain) SO_2 Budget Program and the federal and state NO_x Budget Programs
- New York State limits for sulfur dioxide (SO_2), particulate matter (PM) and opacity
- Reasonably Available Control Technology (RACT) requirements for NO_x
- New York Sate Acid Deposition Reduction Program for NO_x and SO_2
- Carbon Dioxide (CO_2) Budget Trading Program
- Clean Air Interstate Rule (CAIR)

Finally, Facility impacts to ambient air quality are evaluated following the methodology presented in Section 5. The following is a summary of the major elements of the application.

1.2.1 Facility Emissions and Control Requirements

Air emissions from the proposed Facility are primarily products of combustion of natural gas in the combustion turbines and duct burners and ULSD in the combustion turbines. Pollutants regulated under Federal and New York State programs include carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with a diameter of less than 10 microns (PM-10), particulate matter with a diameter of less than 2.5 microns (PM-2.5), volatile organic compounds (VOC), and sulfuric acid (H_2SO_4) mist. A full description of applicable regulations, including regulations less stringent than those summarized here, can be found in Section 3.

1.2.1.1 Best Available Control Technology (BACT)

A BACT analysis consists of an evaluation of environmental, economic, and energy impacts for technically feasible alternative control strategies for the Project. BACT must be applied to control emissions of pollutants that are subject to PSD review. For the CPV Valley Energy Center, BACT is required for NO_x, CO, PM/PM-10, SO_2, and H_2SO_4.

1.2.1.2 Lowest Achievable Emission Rate (LAER)

Both NO_x and VOC are subject to non-attainment NSR. A component of NNSR is a requirement to meet LAER limits. LAER is usually determined by the most stringent emission limitation achieved in practice for a given type of emission source. CPV Valley Energy Center is proposing an enforceable annual emissions cap of 95 tpy for PM-2.5 for the project. This is below the NNSR major source threshold for PM-2.5 of 100 tpy.

Since the Project is located in a moderate ozone non-attainment area, the CPV Valley Energy Center must obtain offsets, also known as Emission Reduction Credits (ERCs), from existing sources equal to 1.15 times its proposed allowable emissions of NO_x and VOC. The State of New York has an agreement with Pennsylvania and Connecticut that allows ERCs to be traded interstate. VOC and NO_x Offsets can be obtained in New York and parts of Pennsylvania or Connecticut according to the “equal or higher” provision which allows offset trades between different non-attainment areas. In addition, a case-by-case demonstration can be made for emission offsets from sources outside of New York State following procedures to be reviewed and approved by NYSDEC.

1.2.1.3 Maximum Achievable Control Technology

The Project's HAP emissions are below 10 tons/year for each individual HAP and below 25 tons/year for all HAPs combined. Thus, MACT is not required.

1.2.1.4 Other NYSDEC Requirements

Pollutants emitted by the Facility are subject to NYSDEC regulatory requirements in addition to the BACT and LAER requirements associated with the PSD and non-attainment NSR programs. Although certain state emission limits are superseded by stricter federal limits (*e.g.*, the 6 NYCRR Subpart 227-2 NO_x RACT is less stringent than LAER), monitoring, reporting and record-keeping requirements under 6 NYCRR Subpart 227-2 must still be followed, as outlined in Section 3. Combined cycle stack emissions of NH_3 will be limited to 5 parts per million (ppm) for natural gas firing and 5 ppm for ULSD firing to meet NYSDEC guidelines for ammonia (NH_3) "slip."

1.2.2 Air Quality Impacts Analysis

The air quality impact analysis (presented in Section 6 of this document) was performed in accordance with procedures documented in a revised air modeling protocol submitted to the USEPA and NYSDEC in November 2008. A prior proposed air quality modeling protocol was submitted to USEPA and NYSDEC in September 2008 and was subsequently modified to address agency comments and to account for project design changes. The dispersion modeling utilizes surface level meteorological data collected by the National Weather Service at Orange County Airport for the years 2002, 2003, 2004, 2005, and 2006 and concurrent upper level meteorological data from Albany International Airport. A waiver from the PSD requirement for pre-construction ambient air quality monitoring must be obtained; otherwise, the Project would need to perform preconstruction ambient monitoring. An application for a waiver from PSD pre-construction monitoring requirements has been submitted separately to EPA.

1.2.2.1 Impact on Ambient Air Quality Standards and PSD Increments

Atmospheric dispersion modeling was performed in accordance with USEPA and NYSDEC modeling guidelines to calculate maximum air quality impacts from the Facility. The results of this modeling show that calculated Facility impacts are predicted to be below established significant impact levels (SILs) for all pollutants except for PM-10. Therefore, the Facility will have no area of significant impact for other criteria pollutants and does not have the potential to affect compliance with National Ambient Air Quality Standards (NAAQS), New York Ambient Air Quality Standards (NYAAQS) or PSD increments. This application includes cumulative impact modeling for PM-10 that demonstrates compliance with ambient standards and PSD increments for that pollutant.

Predicted 24-hour impacts of PM-2.5 during ULSD firing exceed the level of 2.0 ug/m^3 that was recommended for use by the Northeast States for Coordinated Air Use Management (NESCAUM) as a surrogate until EPA formally establishes SILs for PM-2.5 as well as the level of 5.0 ug/m^3 that serves as a threshold for determining potentially significant PM-2.5 under NYSDEC Commissioner's Policy 33 (CP-33). The application includes a modeling demonstration showing that the sum of project impacts and representative background levels will not exceed the ambient standards for PM-2.5.

1.2.2.2 Class I Area Impacts

According to published USEPA guidance, proposed major sources within 100 kilometers (km) of a Class I area must perform an assessment of potential impacts in the Class I area. The nearest Class I areas to the proposed Project are the Edwin B. Forsythe National Wildlife Refuge (NWR) at Brigantine, New Jersey and the Lye Brook National Wilderness Area (NWA) in Vermont, located approximately 206 kilometers to the north and approximately 215 kilometers, respectively from the Project. Based on the level of potential emissions from the Project and distances to the nearest Class I areas, it is expected that the Project will qualify for an exemption from potential Class I impact modeling requirements for air quality related values (AQRV) and visibility. The Project has consulted with the Federal Land Managers for each area to request a determination that the Project would be exempt from any Class I modeling requirement. Even though such an analysis will likely not be required, Level-1 visibility impact screening analyses were conducted for the two closest Class I areas. These analyses demonstrate that predicted visibility impacts are below the Class I default screening thresholds for plume perceptibility and plume contrast. Therefore, it is concluded that the Project will have no significant effect on visibility in Class I areas.

1.2.2.3 Impacts to Soils, Vegetation, Growth, and Visibility

An analysis was performed to assess the Project's impact relative to soils, vegetation, economic growth and visibility. This analysis demonstrates the Project will have negligible effects relative to these special concerns.

1.2.2.4 Class II Area Impacts on Visibility

In response to a request from NYSDEC, an analysis was conducted to assess potential visibility impacts in the Catskills State Park. A Level-1 visibility impact screening analysis was conducted to assess potential impacts on visibility for observers atop significant peaks within Catskills State Park. Even though the stringent Class I default screening thresholds do not apply outside of Class I areas, the results of the analysis indicate that the Project would not have a significant impact on visibility in Catskills State Park.

1.2.2.5 Environmental Justice

The purpose of the environmental justice (EJ) program is to ensure that minority (and in USEPA Region 2 – low-income) communities are not affected adversely or disproportionately by the actions of federal agencies, including approvals of permit applications for facilities such as the Project. The EJ analysis for the Project demonstrated that there is no adverse impact on potential EJ communities. Furthermore, there is no disproportionate impact for areas with a significant percentage of low-income and/or minority populations. The EJ analysis is presented in Section 6.

1.2.2.6 NYSDEC Guideline Concentrations for Air Toxics

NYSDEC has established annual guideline concentrations (AGC) and short-term guideline concentrations (SGC) for various air toxics. This application includes the results of modeling of project emissions of air toxics. The results demonstrate that impacts from the project will not exceed the guideline concentrations listed in the latest version of NYSDEC DAR-1 AGC/SGC Tables (September 2007).

1.3 Conclusions

The conclusions reached from the results of the engineering and air quality modeling analyses are that the CPV Valley Energy Center will: 1) not cause or contribute to a violation of the NAAQS or NYAQS for any pollutant; 2) not cause or contribute to a violation of any PSD increment; 3) meet BACT and LAER; 4) not cause adverse impacts relative to soils, vegetation, growth and visibility; 5) comply with all other applicable federal and state air quality regulatory requirements; 6) have neither an adverse nor a disproportionate impact on communities with a significant percentage of low-income and/or minority populations; and 7) not exceed any NYSDEC guideline concentrations for air toxics.

1.4 Application Forms and Supporting Data

The NYSDEC permit application forms are included as Appendix A of this document. This application seeks a PSD permit and a state construction/operating permit under 6 NYCRR Part 201-5 for the combined cycle units, auxiliary boiler, fuel gas heaters, emergency diesel generator, emergency diesel fire pump and insignificant emissions equipment. No Title V permit application is being filed at this time; it is anticipated a Title V operating permit application would be submitted within one year of commencing operation, as required under Part 201-6. Emission calculation spreadsheets providing supporting calculations for the application forms are included as Appendix B.

1.5 Summary of Proposed Permit Limits

Tables 1-1 and 1-2 present a summary of the permit limits proposed for the Project. These limits reflect the application of LAER or BACT control technology, as appropriate, and have been shown through atmospheric dispersion modeling to not cause or contribute to a violation of the NAAQS.

1.6 Summary of Potential Compliance Provisions

The following defines the potential compliance provisions and measures proposed to ensure attainment thereof. These provisions were developed through review of applicable state and federal regulations and taken, in part, from recent permits issued for similar facilities.

1) Compliance provisions for the applicable regulatory requirements:
   - NSPS Subpart KKKK (emission limits, monitoring and reporting for the combustion turbines and duct burners);
   - NSPS Subpart Dc (emission limits, monitoring and reporting requirements for the auxiliary boiler);
   - NSPS Subpart IIII (emission limits, monitoring and reporting requirements for the emergency diesel generator and emergency fire pump);
   - Title IV Acid Rain Program (continuous emissions monitoring and SO_2 emission allowances);
   - NNSR/PSD (emission limits, testing and NO_x emission offsets); and
   - NO_x Emissions Budget Program (NO_x emissions allowances during the ozone season).
   - New York Sate Acid Deposition Reduction Program for NO_x and SO_2

2) Stack emission limits from the combined cycle units.

3) Monitoring (or surrogate) of combustion turbine exhaust gas for:

nitrogen oxides (NO_x)	carbon monoxide (CO)
% carbon dioxide (CO_2)	% oxygen (O_2)

4) Parameter monitoring (or surrogate) for:

fuel sulfur content	fuel consumption
ammonia slip	SCR operating data

5) Exhaust flow rates and SO_2 mass emissions rates to be calculated based on methods, as opposed to continuous emissions monitoring, in accordance with 40 CFR Part 75.

6) Exhaust testing: Initial testing to verify exhaust parameters and emission rates of all pollutants subject to a permit limitation from the combustion turbines and duct burners.

7) Restriction on ULSD firing in the combustion turbines: equivalent of 720 total turbine-hours per turbine per year firing ULSD.

Table 1-1: Summary of Proposed Permit Limits Combustion Turbine and Duct Burner (Steady-State Operation)				
Pollutant	**Stack Emissions[1,2,3]**			
	Gas Firing		**Oil Firing**	
	(lb/mmBtu)	**(ppm)**	**(lb/mmBtu)**	**(ppm)**
LAER				
Nitrogen Oxides				
CT Only	0.0075	2.0	0.0240	6.0
CT w/ DB	0.0076	2.0	N/A	N/A
Volatile Organic Compounds				
CT Only	0.0028	0.7	0.0010	0.7
CT w/ DB	0.0022	1.8	N/A	N/A
BACT				
Carbon Monoxide				
CT Only	0.0183	2.0	0.0146	2.0
CT w/ DB	0.0078	3.6	N/A	N/A
Particulate Matter[4]				
CT Only	0.0073	N/A	0.0368	N/A
CT w/ DB	0.0062	N/A	N/A	N/A
Sulfur Dioxide				
CT Only	0.0022	N/A	0.0015	N/A
CT w/ DB	0.0022	N/A	N/A	N/A
Sulfuric Acid Mist				
CT Only	0.0007	N/A	0.0005	N/A
CT w/ DB	0.0007	N/A	N/A	N/A
NYSDEC				
PM-2.5				
CT Only	0.0073	N/A	0.0368	N/A
CT w/ DB	0.0062	N/A	N/A	N/A
Ammonia				
CT Only	N/A	5.0	N/A	5.0
CT w/ DB	N/A	5.0	N/A	5.0

[1] "ppm" refers to ppmvd @ 15% O_2; lb/mmBtu limits are HHV basis. All ppm values are one-hour averages, with the exception of NO_x (3-hour average).
[2] Facility may exceed short-term limits during defined startup and shutdown periods.
[3] All proposed emission limits (in units of ppm, lb/hr, and lb/mmBtu) do <u>not</u> serve as the basis for determining annual emission limits. Refer to Appendix B for potential annual emissions calculations.
[4] As PM-10 and includes filterables, condensables, and sulfates.

Table 1-2: Summary of Proposed Permit Limits Combined Cycle Unit Startup and Shutdown				
Gas-fired Startup and Shutdown				
Startup Type	Cold	Warm	Hot	Shutdown
Downtime Prior to Startup (hr)	>48	8-48	8	--
Startup Duration Limit (hr)	2.2	1.6	1.4	1
	Emission Limit (lb/event)[1]			
NO_x	76.5	66.2	52.6	42.5
CO	580.7	539.3	456.1	127.2
VOC	114.6	93.1	71.7	21.6
PM	20.9	15.6	13.0	8.0
Oil-fired Startup and Shutdown				
Startup Type	Cold	Warm	Hot	Shutdown
Downtime Prior to Startup (hr)	>48	8-48	Up to 8	--
Startup Duration Limit (hr)	2.3	1.8	1.6	1
	Emission Limit (lb/event)[1]			
NO_x	189.5	163.6	135.2	110.8
CO	752.1	670.1	572.8	168.5
VOC	435.1	353.6	269.1	86.9
PM	123.4	93.5	80.9	42.4

[1] Emissions for startup and shutdown are on a per unit basis and represent averaged values over two units.

Table 1-3: Summary of Proposed Permit Limits Auxiliary Equipment				
Pollutant	Stack Emissions			
	Auxiliary Boiler	Fuel Gas Heater	Emergency Diesel Generator	Emergency Diesel Fire Pump
	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)
LAER				
NO_x	0.0450	0.0575	1.5036	0.8590
VOC	0.0038	0.0110	0.0331	0.3612
BACT				
CO	0.0721	0.0840	0.1361	0.7533
PM/PM-10	0.0063	0.0076	0.0091	0.0441
SO_2	0.0022	0.0022	0.0014	0.0014
H_2SO_4	0.0002	0.0002	0.00003	0.00003
NYSDEC				
PM-2.5	0.0063	0.0076	0.0091	0.0441

2.0 PROJECT DESCRIPTION

2.1 Facility Conceptual Design

The CPV Valley Energy Center will be a combined cycle 630 MW Facility to be located in the Town of Wawayanda, New York. Figure 2-1 shows the Project location on a topographic map. The proposed Facility will use a combined cycle process, incorporating two CTGs, operating in conjunction with two HRSGs, and one steam turbine generator. By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. The CTG will be equipped with an inlet air cooling system to further boost power and efficiency on hot days. As a result, the new Facility is expected to be dispatched during periods of high demand, displacing older, less efficient generating facilities. Auxiliary equipment will include a natural gas-fired auxiliary boiler, two natural gas-fired fuel gas heaters to heat the natural gas to the optimum firing temperature, an emergency diesel generator, and an emergency diesel fire pump to provide on-site fire-fighting capability. A layout drawing showing proposed equipment locations is presented in Figure 2-2.

2.1.1 Combustion Turbine Generators (CTGs)

CPV Valley Energy Center is proposing to install two F-Class combustion turbines firing natural gas as the primary fuel with ultra low sulfur diesel (ULSD) oil as a backup fuel source for up to the equivalent of 720 hours per year per turbine. The maximum heat input rates for the CTGs at base load and an ambient temperature of -5^{o} F are 2,234 and 2,145 million British thermal units per hour (mmBtu/hr), Higher Heating Value (HHV), for natural gas and fuel oil, respectively. The CTGs will each produce approximately 200 MW (net) of electric power while firing natural gas at 51^{o}F ambient temperature and base load.

2.1.2 Heat Recovery Steam Generator (HRSG)

Exhaust gases from each CTG will be routed through a HRSG to generate steam. The HRSGs will be multi-pressure, horizontal units. The HRSGs will have supplemental fuel firing via a duct burner.

2.1.3 Duct Burner

The duct burner will be natural gas-fired and will have a maximum heat input capacity of 500 mmBtu/hr. The duct burner will only operate when the CTG is operating on natural gas and at maximum turbine load.

2.1.4 Steam Turbine Generator (STG)

Steam generated in the HRSGs will be expanded through an STG to generate electricity. The STG will be multi-stage, non-reheat, condensing turbine. The STG will produce approximately 200 MW of electric power at 51°F ambient temperature; duct burner firing could be used to increase STG output by about 45 MW at this condition.

2.1.5 Air Cooled Condenser (ACC)

The ACC does not constitute a source of air emissions and, as such, is not considered further in this application, except that the structures are included in the building profile analysis for air quality impact modeling.

2.1.6 Combustion Turbine/Duct Burner Air Pollution Control Systems

The emission control technologies proposed for the combustion turbine and duct burner exhaust gases include dry low-NO_x (DLN) combustors located within the combustion turbines and an SCR system located within the HRSGs to control NO_x emissions. Water injection will also be used to minimize emissions of NO_x when the combustion turbines operate on ULSD. An oxidation catalyst and efficient combustion controls will be used to control emissions of CO and VOC. Emissions of SO_2 and PM/PM-10/PM-2.5 will be minimized through the use of pipeline natural gas and ULSD as backup, as well as efficient combustion controls.

2.1.6.1 DLN Combustor

Dry low-NO_x combustion will control NO_x emissions from the CTG. DLN combustion limits NO_x formation by controlling the combustion process through air/fuel optimization.

2.1.6.2 Selective Catalytic Reduction

SCR, a post-combustion chemical process, will be installed within the HRSGs to further treat exhaust gases downstream of the CTGs. Aqueous ammonia will be injected into the flue gas stream, upstream of the SCR catalyst, where it will mix with the NO_x (predominantly NO and NO_2). The mixture will pass through a catalyst bed to reduce NO and NO_2 to nitrogen gas (N_2) and water (H_2O).

Aqueous ammonia with a concentration of 19% or less will be stored on-site. The ammonia will be fed and mixed into the combustion gas stream upstream of the catalyst. The ammonia that does not react will pass through the HRSG and out of the stack. This byproduct is termed "ammonia slip." The SCR system will reduce NO_x concentrations to 2.0 parts per million (ppm) (natural gas firing with and without duct firing) and 6.0 ppm (ULSD firing) with an average ammonia slip of 5.0 ppm when firing natural gas and 5.0 ppm for ULSD firing.

2.1.6.3 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 system will reduce CO concentrations to 2.0 ppm (natural gas firing without duct firing), 3.6 ppm (natural gas firing with duct firing) and 2.0 ppm (ULSD firing). The oxidation catalyst will also reduce VOC emissions to 0.7 ppm without duct firing when firing gas and oil and 1.8 ppm with duct firing when firing gas. The oxidation catalyst will be located in an optimum temperature region within the HRSG immediately upstream of the SCR ammonia injection grid.

2.1.6.4 Process Controls

The Project will incorporate modern data acquisition and control systems, which will optimize combustion performance. These same systems will minimize pollutant emissions through a combination of operator and software-driven process adjustments and notifications.

2.1.7 Auxiliary Boiler

An auxiliary boiler will operate as needed to keep the HRSG warm during periods of turbine shutdown and to provide sealing steam to the steam turbine in the case of warm and hot shutdowns. The auxiliary boiler will have a maximum heat input of 73.5 mmBtu/hr and will be fired exclusively with natural gas. Total boiler hours for the Facility will be limited to 2,000 hours per year.

2.1.8 Fuel Gas Heaters

Used to heat the incoming natural gas before being fired in the combustion turbine and duct burner, the fuel gas heaters are proposed to operate the entire year and will fire only natural gas. Heating of the gas above its dew point temperature reduces the possibility of the gas "slushing" or condensing into a liquid due to change in pressure and temperature. This could result in combustor flashback or fire in the gas turbine, posing a serious threat of turbine damage. As such, the temperature of the gas supplied to the gas turbine is required to be maintained at a temperature of 50°F or more above the dew point of the gas. The fuel gas heaters will each have an approximate maximum heat input of 5.0 mmBtu/hr. The fuel gas heater will use a low-NO_x forced draft burner to reduce potential emissions of NO_x by approximately 50%.

2.1.9 Emergency Diesel Generator

The Project will include a 1.5 MW emergency diesel generator. This unit will fire ULSD and will typically be operated only for testing and to maintain operational readiness or if needed for emergency operation. It will be limited to a maximum of 500 hours per year of operation.

2.1.10 Emergency Diesel Fire Pump

The Project will have a backup fire pump to provide on-site fire fighting capability independent of the utility grid. The emergency diesel fire pump will fire ULSD and will be limited to 500 hours per year.

2.1.11 Exhaust Stacks

After passing through the HRSG and air pollution control systems, the exhaust gases (consisting primarily of nitrogen, oxygen, water and carbon dioxide) will be discharged to the atmosphere. Each combined cycle unit will exhaust to a 275-foot dedicated stack with an inner exit diameter of 19 feet. Stack emissions (CO and NO_x) will be monitored and recorded by a continuous emissions monitoring system (CEMS).

2.1.12 Fuel Oil Storage Tank

The Project will store ULSD in a 965,000-gallon tank, in order to provide a backup fuel supply for the Project. The tank will be equipped with modern vapor recovery systems. VOC emissions from the tank are calculated and included in the Facility's potential emissions.

2.2 Fuel

CPV Valley is proposing to utilize pipeline natural gas as the primary fuel for the CTGs with ULSD as a backup fuel. The natural gas is assumed to have a HHV of approximately 1,048 Btu/standard cubic foot (SCF) and will contain no more than 0.8 grains of sulfur per 100 SCF on an annual average basis. The ULSD is assumed to have a HHV of approximately 139,728 Btu/gallon with a sulfur content of 15 ppm by weight. ULSD firing in each combustion turbine will be limited to the equivalent of 720 hours per year.

2.3 Facility Operating Modes

The combined cycle units will typically operate at or near full load to meet electricity demand as needed. Depending upon demand and fuel, the unit can operate at loads ranging from 60% to 100% of full capacity. Combustion turbine performance and emissions are affected by ambient temperature with turbine fuel consumption, power output and emissions (on a lb/hr basis) increasing at lower ambient temperatures.

Because of the different emission rates and exhaust characteristics, a matrix of operating modes is employed in the various analyses presented in this air permit application, including air quality impact analysis and potential emission calculations. Exhaust and emission parameters for three ambient temperatures (-5°F, 51°F and 90°F), three turbine loads (maximum, minimum, and intermediate), duct burner operation, and two fuels (natural gas and ULSD oil) are accounted for in this air permit application to cover the range of combined cycle operations.

Combined cycle startup and shutdown scenarios are also accounted for in this air permit application. Startup and shutdown conditions refer to all times when the CTG operates below the minimum operating load (60% load for natural gas firing and 70% load for ULSD firing). Startups are defined as cold, warm, and hot. The cold startup refers to startups after 48 hours of shutdown time and requires approximately 2.3 hours. The warm startup refers to startups after typically 8.1 – 48 hours of shutdown time and requires approximately 1.8 hours. The hot startup refers to a typical shutdown time of about 8 hours or less and can be achieved in 1.6 hours.

2.4 Source Emission Parameters

Emissions of air contaminants from the proposed CPV Valley Energy Center have been estimated based upon vendor emission guarantees, emission factors presented in USEPA's *Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources* (AP-42), other published emission factors, mass balance calculations and engineering estimates. Emission calculations used to develop the emission estimates presented in this application are presented in Appendix B of this application.

2.4.1 Criteria Pollutant Emissions from the Combustion Turbines

Exhaust and emission parameters are presented for three ambient temperatures (-5°F, 51°F and 90°F), three turbine loads, inlet air cooling, duct burner operation, and two fuels (natural gas and ULSD oil). Exhaust characteristics and emission rates for the combined cycle units are provided in Appendix B. Uncontrolled and controlled emission rates for all criteria pollutants and ammonia slip for the combustion turbine/duct burner unit are based upon vendor emission estimates. The PM-10 and PM-2.5 emissions estimates obtained from the vendor include condensable particulate matter and an allowance for sulfuric acid and/or ammonia salt formation due to reaction of sulfur trioxide (SO_3) with water or excess ammonia (NH_3).

In addition to the combined cycle unit emissions, Appendix B includes estimates for combined cycle startup and shutdown emissions, including the hot, warm, and cold startup scenarios described in Section 2.3 for gas-fired and ULSD-fired operation. These are based on vendor estimates. The startup emissions are included in calculations of potential emissions based on an analysis of worst-case annual operating scenarios as described in Section 2.4.3 and are conservatively evaluated in the air quality impact modeling analysis as well. Proposed startup emission limits correspond to the worst case emission rates, on a pounds per event basis for NO_x, CO, VOC and PM/PM-10/PM-2.5.

2.4.2 Other Pollutant Emissions from the Combustion Turbines

Potential annual emissions of HAPs from the operation of the combustion turbines have been quantified based on AP-42 emission factors with the exception of formaldehyde, which is based on California Air Resources Board (CARB) emissions test data that is more appropriate for advanced-technology dry low-NO_x model units such as the SWPC SGT6-5000F.

SCR control for NO_x reduction involves the use of ammonia, which acts to remove NO_x as the flue gas passes through a catalyst. Some of the ammonia does not react with the NO_x and ends up being emitted into the atmosphere. The emission of unreacted ammonia from an SCR is known as "ammonia slip." The maximum emission of ammonia slip will not exceed 5 ppm when the CTGs are firing natural gas and 5 ppm when the CTGs are firing ULSD.

HAP and ammonia slip emissions are quantified in Appendix B.

2.4.3 Potential Annual Emissions from the Combustion Turbine Units

Annual operation of the Facility will be limited on the basis of a PM-2.5 emissions cap of 95 tons per year. The potential to emit for all criteria pollutants other than PM/PM-10/PM-2.5 were based on the following worst-case operating scenarios:

- Year-round (8,760 hours), full load operation of the combustion turbine on natural gas (at 51°F ambient temperature);
- A duct burner capacity factor of 30%, equivalent to 2,628 hours of duct firing for each combustion turbine;
- The equivalent of up to 720 hours per year per turbine of ULSD firing; and
- A total of 275 annual combined cycle shutdown/startup events per turbine, including up to 40 cold starts, were also included for each case.

Potential annual emissions of PM-2.5 from the proposed Project will be capped to 95 tons per year. To ensure compliance with the cap, CPV will track PM-2.5 emissions for the turbine on a monthly basis using the following equation:

$$\left(0.0062\frac{lb}{mmBtu}\right)*\left(\frac{mmBtu\ of\ NG\ firing\ w/\ DB}{month}\right)+\left(0.0073\frac{lb}{mmBtu}\right)*\left(\frac{mmBtu\ of\ NG\ firing\ w/o\ DB}{month}\right)+\left(0.0368\frac{lb}{mmBtu}\right)*\left(\frac{mmBtu\ of\ oil\ firing}{month}\right)=\frac{lbs\ PM2.5}{month}$$

Each month CPV will add the total calculated pounds of PM-2.5 to the previous eleven months to determine a 12-month running total for PM-2.5 emissions from the turbines. This value will then be added to PM-2.5 emissions from the facility's auxiliary boiler, fuel gas heaters, and emergency diesel equipment to ensure PM-2.5 emissions from the facility will not exceed 95 tons/year (as calculated on a 12-month rolling total basis).

2.4.4 Potential Annual Emissions from the Auxiliary Boiler

Emission rates for NO_x, CO, VOC, SO_2, and PM/PM-10/PM-2.5 from the natural gas-fired auxiliary boiler have been estimated based upon vendor emission estimates. Potential HAP emissions are based on emission factors from AP-42 Chapter 1.4 (July 1998) and Chapter 1.3 (September 1998). Emission estimates are presented in Appendix B. Potential emissions are based on 2,000 hours of operation per year.

2.4.5 Potential Annual Emissions from the Fuel Gas Heaters

Emission rates for NO_x, CO, VOC, SO_2, and PM/PM-10/PM-2.5 from the two fuel gas heaters are estimated based upon vendor emission estimates. Each fuel gas heater will use a low-NO_x forced draft burner to reduce emissions of NO_x by approximately 50% and is proposed to operate all year. Potential HAP emissions are based on emission factors from AP-42 Chapter 1.4 (July 1998). Emission estimates are presented in Appendix B.

2.4.6 Potential Annual Emissions from the Emergency Diesel Generator

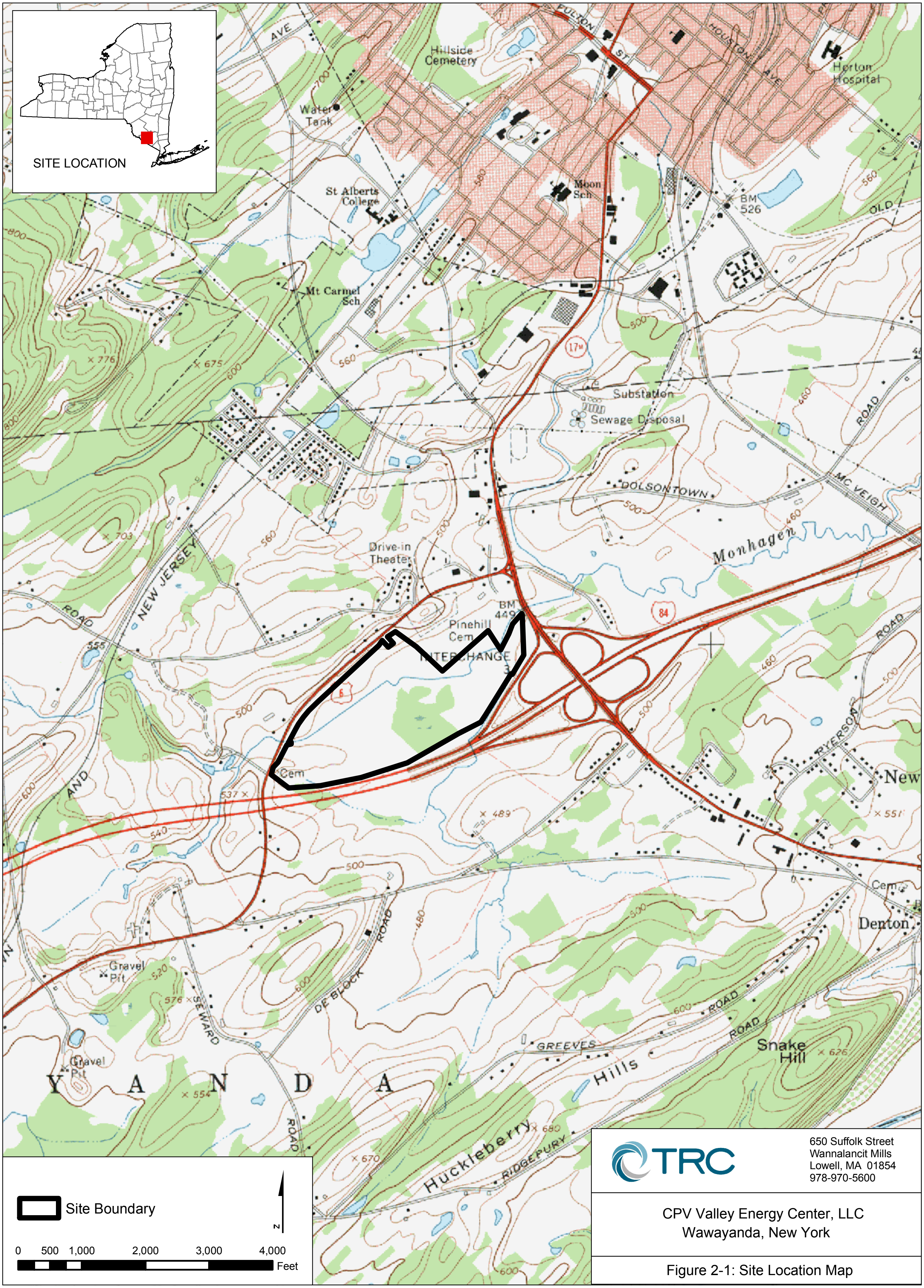
Emission rates for NO_x, CO, VOC, SO_2, and PM/PM-10/PM-2.5 from the emergency generator have been estimated based upon vendor emission estimates with SO2 emissions calculated using a mass balance. The emergency generator will operate for a maximum of 500 hours per year. Potential HAP emissions are based on emission factors from AP-42 Chapter 3.3 (October 1996). Emission estimates are presented in Appendix B.

2.4.7 Potential Annual Emissions from the Emergency Diesel Fire Pump

Emission rates for NO_x, CO, VOC, SO_2, and PM/PM-10/PM-2.5 from the emergency diesel fire pump have been estimated based upon vendor emission estimates with SO2 emissions calculated using a mass balance. The fire pump will operate for no more than 500 hours per year. Potential HAP emissions are based on emission factors from AP-42 Chapter 3.3 (October 1996). Emission estimates are presented in Appendix B.

2.4.8 Potential Annual Emissions from Miscellaneous Sources

Potential VOC emissions from the ULSD storage tank have been estimated at 0.10 tons/year, as calculated using the USEPA computer program TANKS 4.09d, based upon estimated storage tank dimensions, color, throughput, and other parameters, including local climatology, venting parameters, etc. TANKS 4.09d printouts are presented in Appendix B.



650 Suffolk Street
Wannalancit Mills
Lowell, MA 01854
978-970-5600

CPV Valley Energy Center, LLC
Wawayanda, New York

Figure 2-1: Site Location Map

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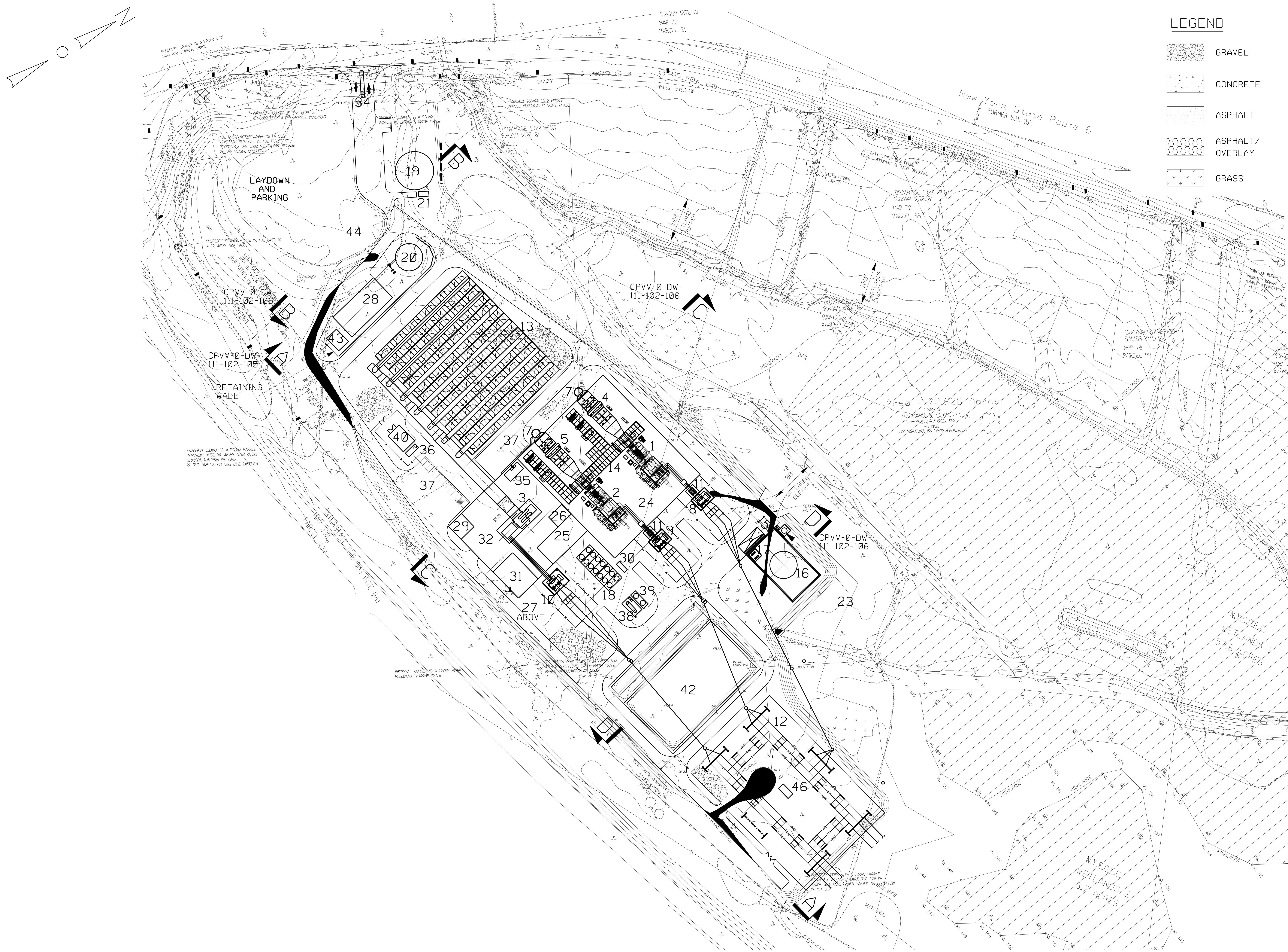


LEGEND

- GRAVEL
- CONCRETE
- ASPHALT
- ASPHALT/ OVERLAY
- GRASS

EQUIPMENT DESCRIPTION

1 CTG #1
2 CTG #2
3 STG
4 HRSG #1
5 HRSG #2
6 NOT USED
7 HRSG STACK
8 GSU TRANSFORMER #1
9 GSU TRANSFORMER #2
10 GSU TRANSFORMER #3
11 AUXILIARY TRANSFORMER
12 SWITCHYARD
13 AIR COOLED CONDENSER
14 PIPE RACK
15 TRUCK UNLOADING AREA
16 FUEL OIL TANK
17 FUEL OIL PUMPS
18 AUXILIARY FIN-FAN COOLER
19 RECALIM/FIRE WATER STG TK (1,000,000 GAL)
20 DEMINERALIZED WATER TK (400,000 GAL)
21 FIRE WATER PUMP BUILDING
22 WTR TRT LV SWITCHGEAR & XFMRS
23 AQUEOUS AMMONIA TANK & PUMPS
24 COMBUSTION TURBINE BUILDING
25 ELECTRICAL EQUIPMENT ROOM
26 CONTROL ROOM
27 ADMINISTRATION OFFICES
28 WATER TREATMENT BUILDING
29 MAINTENANCE
30 OILY WATER SEPARATOR
31 WAREHOUSE
32 STEAM TURBINE GENERATOR BUILDING
33 PERIMETER FENCING
34 MAIN PLANT ENTRANCE/GUARD SHACK
35 AUX. BOILER
36 DEW POINT HEATER
37 PLANT PARKING
38 DIESEL GENERATOR
39 DIESEL GENERATOR AUX COOLER
40 NATURAL GAS METER. & FILTER AREA
41 NOT USED
42 STORM WATER POND
43 PROCESS WATER SUMP
44 CONDENSATE MAKE-UP PUMPS
45 NOT USED
46 SWITCHYARD CONTROL BLDG.

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH. SPEC.	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
H	05 01 08	REMOVED SIEMENS FROM TITLE BLOCK	RAK		JEV				HNG
G	02 20 08	ADDED SIEMENS SGT6-5000F IN LIEW OF GE 7FA, REVISED SWITCHYARD ORIENTATION	JEV		JEV				HNG
F	02 01 08	REVISED SWITCHYARD AND ADDED LEGEND	JEV		JEV				HNG
E	01 04 08	UPDATED TO INCORPORATE COMMENTS	JEV		JEV				HNG
D	11 08 07	ADDED ELEVATION REFERENCES	JEV		JEV				HNG
C	10 31 07	GENERAL REVISION	JEV		JEV				HNG
B	10 22 07	OVERALL UPDATE FOR REVIEW	JEV		JEV				HNG
J	10 06 08	INCORPORATED COMMENTS	JEV		JEV				HNG

PRELIMINARY STATUS DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
LDE

APPROVED STATUS DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
LDE

ORIGINATING PERSONNEL

DRAWN BY: JEV
CHECKED BY:
LEAD DESIGNER: JE VEEN
ENGINEER/TECH SPECIALIST:
PROJECT ENGINEERING MANAGER:
PROJECT MANAGER: HN GOLDSTEIN

PROFESSIONAL ENGINEER'S SEAL

Zero Harm — Leadership, No Incidents, Safe Behavior

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE#: ______ STATE: ______
LIC. NO.: ______ DATE: ______

WorleyParsons
resources & energy

CLIENT/PROJECT TITLE
CPV VALLEY LLC
CPV VALLEY ENERGY CENTER

FIGURE 2-2

GENERAL ARRANGEMENT
SITE PLAN
2x1 COMBINED CYCLE

SCALE: 1"=100'
DRAWING SIZE: ARCH D (36" x 24")
WORLEYPARSONS DWG. NO.: CPVV-0-DW-111-002-101
REV: J

CONCEPTUAL DESIGN STUDY
FOR REVIEW ONLY

100 0 100 200 300
SCALE: 1" = 100'

...\cpvv-0-dw-111-002-101.dgn
10/6/2008 3:19:14 PM

3.0 APPLICABLE REQUIREMENTS AND REQUIRED ANALYSES

CPV Valley Energy Center is seeking New York State air quality permit approvals to construct and operate a nominal 630-megawatt (MW) combined cycle electric generating facility in the Town of Wawayanda, New York. The CPV Valley Energy Center is considered a new major stationary source under PSD and Non-Attainment NSR regulations because potential annual emissions exceed major source applicability thresholds.

This section contains an analysis of the applicability of federal and state air quality regulations to the proposed CPV Valley Energy Center. The specific regulations included in this review are Federal NSPS, NYSDEC Requirements, Non-Attainment NSR Requirements, PSD Requirements, Air Quality Impacts Analysis Requirements, Federal Acid Rain Program Requirements, and Federal NO_x Budget Program Requirements.

3.1 Federal New Source Performance Standards

The NSPS are technology-based standards applicable to new and modified stationary sources. The NSPS requirements have been established for approximately 70 source categories. Based upon a review of these standards, five subparts are applicable to the proposed Facility: General Provisions (40 CFR Part 60, Subpart A), the Standards of Performance for Stationary Combustion Turbines (40 CFR Part 60, Subpart KKKK), the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc), the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII), and 40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984).

3.1.1 40 CFR Part 60, Subpart A – Combustion Turbine, Duct Burner, Auxiliary Boiler, Emergency Diesel Engines and Fuel Oil Storage Tank

The combustion turbine, duct burner, auxiliary boiler, emergency diesel engines and fuel oil storage tank are subject to the general provisions for NSPS units in 40 CFR Part 60 Subpart A. These may include the requirements for notification, record keeping, and performance testing contained in 40 CFR Parts 60.7 and 60.8 listed as:

40 CFR 60.7 Notification and Record Keeping

(a)(1) A notification of the date of construction start – no later than 30 days after such date.
(a)(3) A notification of actual date of initial startup – within 15 days after such date.

(a)(5) A notification of the date of continuous monitoring system performance commences – not less than 30 days prior to such date.

(b) Maintain quarterly records of the startup, shutdown, or malfunction of facility, air pollution control equipment, or continuous monitor system.

(c) Excess emissions reports - by the 30^{th} day following end of each quarter. (required even if no excess emissions occur).

(f) Maintain file of all measurements, maintenance, reports, and records for two years.

40 CFR 60.8 Performance Tests

(a) Performed within 60 days after achieving maximum production rate but no later than 180 days after initial startup.

(d) Notification of performance tests at least 30 days prior.

3.1.2 40 CFR 60, Subpart KKKK – Combustion Turbines and Duct Burners

The combustion turbines and duct burners are subject to the provisions of 40 CFR Part 60 Subpart KKKK by virtue of the maximum firing capacity of the units and the proposed date of installation. For turbines greater than 850 mmBtu/hr firing, this subpart limits flue gas concentrations of NO_x to 15 ppm when firing natural gas and 42 ppm when firing fuels other than natural gas. The air pollutant emission standard for SO_2 emissions limits the turbine emissions to 0.90 lb/MWh gross output or 0.060 lb/mmBtu heat input. The proposed emissions based on natural gas and fuel oil operations are well below these levels.

Additionally, the provisions of this subpart require continuous monitoring of water-to-fuel ratio, but allow for the use of either a 40 CFR Part 60 or Part 75 certified NO_x CEMS in lieu of this monitoring requirement. CPV Valley is proposing to use 40 CFR Part 75 certified NO_x CEMS to comply with this requirement.

3.1.3 40 CFR 60, Subpart Dc – Auxiliary Boiler

The auxiliary boiler is subject to the provisions of 40 CFR Part 60, Subpart Dc because its maximum heat input capacity is between 10 and 100 mmBtu/hr. Subpart Dc requires an initial notification for each unit and one-time opacity test for boilers that operate only on natural gas such as the one proposed. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis, however since natural gas is the only fuel burned in the proposed boiler, there is no reporting requirement to EPA.

3.1.4 40 CFR Part 60, Subpart IIII – Emergency Diesel Engines

The emergency diesel generator and the emergency fire pump are subject to the provisions of 40 CFR Part 60, Subpart IIII. For model year 2009 and later fire pump engines with a displacement less than 30 liters per cylinder and an energy rating between 300 and 600 hp, Subpart IIII limits NMHC + NO_x emissions to 4.0 g/kW-hr and PM emissions to 0.2 g/kW-hr. To comply with Subpart IIII, the emergency diesel generator must meet the emission standards for new nonroad CI engines. These limits are 6.4 g/kW-hr for NMHC + NO_x, 3.5 g/kW-hr for CO and 0.20 g/kW-hr for PM. In addition to the emission limits, beginning on October 1, 2010 all stationary CI internal combustion engines with a displacement of less than 30 liters per cylinder must use diesel fuel with a maximum sulfur content of 15 ppm. The proposed limits for the emergency engines meet these limits. In addition, CPV Valley will be burning ULSD in these units which meets the 15 ppm maximum sulfur in fuel limit.

3.1.5 40 CFR 60, Subpart Kb – Fuel Oil Storage Tank

The Project will include a volatile organic liquid storage vessel (oil tank) with a capacity greater than 40 cubic meters. As such the tank will be subject to 40 CFR 60 Subpart Kb. Since the vapor pressure of the distillate oil tank is less than 3.5 kPa, the only requirement applicable is the recordkeeping requirement specified in 40 CFR 116b(b). The Facility will maintain records showing the dimensions and capacity of the oil storage tank.

3.2 NYS Department of Environmental Conservation Regulations and Policy

Applicable NYSDEC Air Regulations are identified below:

- Part 200 defines general terms and conditions, requires sources to restrict emissions, and allows NYSDEC to enforce NSPS, PSD, and NESHAP. Part 200 is a general applicable requirement; no action is required by 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 CPV Valley Project will represent a new major Part 201 source, is seeking a construction/operation permit under 201-5 with this application, and will apply for a Title V operating permit under 201-6 within one year of commencing operation.

- Part 202-1 requires a source to conduct emissions testing upon the request of NYSDEC. NYSDEC has the right to require stack testing of new or existing sources. Permit conditions covering construction of the proposed Project will likely require stack testing as a condition of receiving permission to operate.

- Part 202-2 requires sources to submit annual emission statements for emissions tracking and fee assessment. Pollutants are required to be reported in an emission statement if certain annual thresholds are exceeded. Project emissions will be reported as required.

- Part 204 regulates the NO_x Budget program for the year 2003 ozone season and beyond. 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 more fully addressed in Section 3.6 of this application).

- Part 211-3 defines general opacity limits for sources of air pollution in New York State. General applicable requirement facility-wide visible emissions are limited to 20% opacity (6-minute average) except for one continuous six-minute period per hour of not more than 57% opacity. Note that the opacity requirements under Part 227-1 (see below) are more restrictive and supersede the requirements of Part 211-3.

- Part 225-1 regulates sulfur content of fossil fuels. For facilities located in Orange County, fuel sulfur is limited to 2% by weight for fuel oil. CPV Valley, however, proposes to use much cleaner 0.0015% sulfur ULSD. The Project will not fire residual oil.

- Part 227-1.2 sets a 0.10 lb/mmBtu particulate limit for oil-fired stationary combustion installations with a maximum heat input capacity exceeding 250 mmBtu/hr. CPV Valley proposes to comply with this emission limit by proposing a maximum particulate limit of 0.0368 lb/mmBtu when the combustion turbine is operating on fuel oil.

- Visible emissions (opacity) for stationary fuel-burning equipment are regulated under 6 NYCRR Subpart 227-1.3. Facility stationary combustion installations must be operated so that the following opacity limits are not violated; 227-1.3(a) 20% opacity (six minute average), except for one six-minute period per hour of not more than 27% opacity.

- Part 227-2 sets NO_x RACT emission limits for combustion sources. Under 227-2.4(e), the combined cycle combustion turbine must meet a NO_x RACT limit of 42 ppm and 65 ppm, dry volume, corrected to 15% O_2, when firing natural gas and oil, respectively. The proposed NO_x emission limits for this Project (2.0 ppm for gas firing without/with duct firing and 6.0 ppm for oil firing) will be significantly more restrictive. Recordkeeping and reporting requirements under Part 227-2 will apply.

- Part 231 requires new source review of new major sources and/or major modifications of existing facilities in USEPA-designated non-attainment areas. Under Subpart 232-2, which regulates sources that were operational after November 14, 1992, CPV Valley must address LAER for NO_x and VOC, since potential annual emissions are greater than the corresponding major source threshold. Non-attainment emission offsets will also need to be purchased for NO_x and VOC. See Section 3.5 for a complete analysis of all Part 231 requirements.

- New York State has promulgated its Acid Deposition Reduction Program (ADRP). As such, the SO2 and NO_x Budget trading programs established in 6 NYCRR Parts 237 and 238 are in effect, and will apply to the facility (25 MW threshold) once operation commences. As with the Federal NO_x and SO_2 Trading Programs, affected facilities must hold allowances in their account equal to emissions at the program settlement date. The ADRP NO_x Budget Program will extend NO_x allowances requirements to a year-round basis.

- New York has promulgated its CO_2 Budget Trading Program under 6 NYCRR 242. Program components include allowance allocations, tracking, transfers, CO_2 monitoring and reporting requirements and regulatory timelines. (CO_2 Budget program requirements are more fully addressed in Section 3.8 of this application).

- 6 NYCRR Parts 243, 244 and 245 establish New York's Clean Air Interstate Rule (CAIR). For a more detailed discussion of CAIR see Section 3.9 of this application.

- Under 6 NYCRR 257, New York's ambient air quality standards, Project emissions must be such as not to exceed state ambient air standards for SO_2, PM, CO, photo-chemical oxidants, NO_2, fluorides, beryllium and hydrogen sulfide.

- To meet NYSDEC guidelines for ammonia (NH_3) "slip", combined cycle stack emissions of NH_3 will be limited to 5 ppm when the CT is firing natural gas and 5 ppm when the CT is firing ULSD. This will be accomplished by controlling the NH_3 injection rate and employing good operating practices.

Other NYSDEC requirements, not directly related to emissions from the proposed Facility, but potentially related to the new Facility in general, including 6 NYCRR Parts 207 (air pollution episode control measures), Part 215 (open fires), and Part 221 (asbestos-containing surface coating material), will be addressed and/or incorporated into the Part 201-6 Title V permit pursuant to established regulatory deadlines.

3.3 Attainment Status and Compliance with Air Quality Standards

USEPA has established NAAQS for several criteria pollutants for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), PM-2.5, PM-10, nitrogen dioxide (NO_2), CO, ozone (O_3), and lead (Pb). USEPA has set both primary and secondary NAAQS. The results of clinical and epidemiological studies established the primary NAAQS to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. The secondary NAAQS protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. USEPA has established both short-term and long-term standards.

The NYSDEC has adopted the NAAQS as the NYAAQS, as shown in Table 3-1. In addition, NYSDEC has NYAAQS for total suspended particulates (TSP), gaseous fluoride, beryllium, and hydrogen sulfide.

The proposed location of the Project is an area currently designated as attainment or unclassifiable for SO_2, CO, NO_2, and PM-10. Therefore, for these pollutants, the Project is required to demonstrate compliance with the NYAAQS and NAAQS shown in Table 3-1. The only criteria pollutants for which the Project is located in a non-attainment area are ozone and $PM_{2.5}$. Orange County is designated as a Subpart 2 / Moderate Non-attainment area with respect to the 8-hour ozone NAAQS. The Project is in a portion of Orange County (the Poughkeepsie Area) that was formerly designated as moderate non-attainment with respect to the 1-hour ozone NAAQS. However, the 1-hour ozone standard was revoked effective June 15, 2005 in all areas of New York. Orange County is also designated as non-attainment with respect to $PM_{2.5}$.

It should be noted that New York State's current non-attainment area regulations in the New York Codes, Rules and Regulations (NYCRR) at Part 231-2 still reference the 1-hour ozone NAAQS and have not yet incorporated the 8-hour NAAQS. The Project site is located in the "Lower Hudson Valley area" as defined in Part 200.1(av)(3)(ii)(a), an area designated as moderate non-attainment for ozone. Therefore, under both federal and state rules, the Project is in a non-attainment area for ozone. Therefore, facilities emitting more than 100 tons/yr of NO_x, 50 tons/yr of VOC and 100 tons/yr PM-2.5 (or 100 tons/yr of SO2 as a PM-2.5 precursor) are subject to Non-Attainment NSR requirements for these pollutants.

In order to identify those new sources with the potential to impact ambient air quality, the USEPA and the NYSDEC have adopted Significant Impact Levels (SILs) for NO_2, SO_2, CO, and PM-10, as shown in Table 3-1. New sources that have maximum predicted 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 USEPA, sources with predicted impacts below the SILs do not warrant such an assessment. The Project has calculated air quality Project impacts that are less than the SILs for NO_x, CO, and SO2. For PM-10 the Project has calculated impacts greater than the 24-hour SIL for cases where the combustion turbines fire ULSD, and a cumulative modeling analysis has been performed. Complete modeling analyses are discussed in Section 5. An ambient impact analysis has also been conducted for PM-2.5.

3.4 Prevention of Significant Deterioration

A combined cycle power plant with potential emissions of one or more criteria pollutants in excess of 100 tons per year is considered a new major stationary source. As shown in Table 3-2, regulated criteria pollutant emissions of at least one pollutant will exceed this threshold. Thus, the proposed Facility will be subject to PSD review.

The PSD regulations state that facilities subject to PSD review must perform an air quality analysis (which can include atmospheric dispersion modeling and pre-construction ambient air quality monitoring), a BACT analysis, and an additional impact analysis for those pollutants which exceed the pollutant-specific significant emission rates identified in the regulations. Table 3-2 shows that PSD review is required for NO_x, CO, PM/PM-10, SO_2 and H_2SO_4 emissions. Since the LAER requirements are at least as stringent as BACT, the LAER analysis will satisfy the technology requirements for NO_x. The BACT analysis for CO, PM/PM-10/PM-2.5, SO_2, and H_2SO_4 is included in Section 4.

In addition to assessing impacts on NAAQS, facilities subject to PSD review must demonstrate compliance with the PSD increments established for SO_2, NO_2, and PM-10. The proposed CPV Valley Project site is located in a PSD Class II area and will be subject to the PSD Class II increments, as well as the NAAQS. The Class II PSD increments are presented in Table 3-1.

3.4.1 Ambient Air Quality Monitoring

Proposed facilities subject to PSD review may have to perform up to one year of pre-construction ambient air quality monitoring for those pollutants with emission rates exceeding the thresholds specified in 40 CFR 52.21(i)(8)(i) and shown in Table 3-3, unless granted an exemption by the reviewing agency. USEPA may grant an exemption from monitoring if the proposed source demonstrates that it will have maximum impacts below the pollutant-specific Significant Monitoring Concentrations that are presented in Table 3-3, or if representative quality-assured data already exist. CPV Valley has separately filed an application with USEPA for a waiver from pre-construction ambient air quality monitoring based on its predicted Project impacts.

3.4.2 Impact Area Determination

The impact on air quality must be determined for each pollutant subject to PSD review. When modeled concentrations of applicable pollutants are greater than the SILs, as (SIA) is defined as the area within the greatest distance from the facility at which the modeled concentrations are greater than the PSD SILs. Based on the modeling analysis presented in Section 5, calculated impacts of all pollutants except for PM-10 are less than the SILs and, as such, no further cumulative impact modeling is required for pollutants other than PM-10. Additional cumulative impact modeling analyses were conducted for PM-10 to demonstrate compliance with ambient air quality standards and PSD increments for PM-10. The maximum extent of the predicted SIA for the project was approximately 4.6 km.

3.4.3 Additional Impact Analyses

As required as part of PSD review and NYSDEC regulations, certain additional analyses are required as explained in the draft USEPA Guidance Document *New Source Review Workshop Manual*, (October 1990). These include a growth analysis (and estimation of any growth-related emissions) and modeling to assess potential for impacts to visibility, soils and vegetation in the area surrounding the proposed Project.

3.4.4 Impacts on Class I Areas

According to published USEPA guidance, proposed major sources within 100 km of a Class I area must perform an assessment of potential impacts in the Class I area. The nearest Class I areas to the proposed Project are the Edwin B. Forsythe National Wildlife Refuge (NWR) at Brigantine, New Jersey and the Lye Brook National Wilderness Area (NWA) in Vermont, located approximately 206 kilometers to the north and approximately 215 kilometers, respectively from the Project. Based on the level of potential emissions from the Project and distances to the nearest Class I areas, it is expected that the Project will qualify for an exemption from potential Class I impact modeling requirements for air quality related values (AQRV) and visibility. The Project has consulted with the Federal Land Managers for each area to request a determination that the Project would be exempt from any Class I modeling requirement.

3.4.5 Environmental Justice

The purpose of the EJ program is to evaluate whether minority (and in USEPA Region 2 – low-income) communities are affected adversely or disproportionately by the actions of federal agencies, including approvals under the PSD program. The EJ analysis is presented in Section 6.

3.4.6 Endangered Species Act

The Endangered Species Act of 1973, as amended (ESA) requires that all federal actions, such as the issuance of PSD permits, will not jeopardize the existence of any endangered or threatened species or result in the destruction or adverse modification of the habitat of such species. In accordance with the ESA, CPV Valley Energy Center has consulted with the Fish and Wildlife Service (FWS). A copy of the initial correspondence is included in Appendix C. CPV Valley is continuing to work with the FWS to ensure that the Project will have no adverse impacts. Any future copies of correspondence will be submitted to EPA upon receipt.

3.5 Non-Attainment New Source Review Requirements

The Project is subject to major non-attainment review for NO_x and VOC. Major NNSR will not apply for PM-2.5 because the project is proposing an emissions cap to limit annual PM-2.5 emissions to less than the major source threshold of 100 tpy. The pre-construction review requirements for major new sources or major modifications located in areas designated non-attainment pursuant to Section 107 of the Clean Air Act Amendments of 1990 (CAAA) differ from the PSD requirements. 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 areas designated by USEPA as 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, (i.e., ERCs). Additional requirements specific to offsetting are provided in 6 NYCRR 231-2.4:

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 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 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 231-2.4(a)(2)(ii)).

3.5.1 Emissions Offset Requirements

A major source or major modification planned in a USEPA-designated 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 or modification, (2) provide a net air quality benefit on balance (for CO, PM-10 and PM-2.5 offsets only), and (3) satisfy a "contribution test" for VOC and NO_x offsets. These offsets, obtained from existing sources that implement a permanent, enforceable, quantifiable and surplus emissions reduction, must equal the emissions increase from the new source or modification multiplied by an offset ratio.

3.5.2 Emission Reduction Credit Requirements

The Project is located in a non-attainment area for ozone and will be required to purchase ERCs for NO_x and VOC. Emission offset requirements will not apply for PM-2.5, since the project is proposing an emissions cap to limit PM-2.5 emissions for the project to 95 tpy, a level below the NNSR major source threshold. The USEPA allows ERCs to be traded across state lines and the State of New York has reciprocal trading agreements with Pennsylvania and Connecticut for NO_x and VOC. The calculation of required offsets for the proposed Project is presented in Table 3-4.

3.5.3 Availability and Certification of Emission Reduction Credits

As was previously noted, each emission source providing offsets must be identified along with the proposed mechanism to effect the emission reduction. 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.” If the source identification changes after issuance of a draft permit for the Project, then the offset transaction will be subject to an additional notice and comment process from the air permit application itself. ERCs may be created from past or future facility shutdowns, emission unit shutdowns or other reduction mechanisms acceptable to NYSDEC.

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 CPV Valley in obtaining the required offsets. As of October 1, 2008, the ERC Registry reported more than 9,900 tons of NO_x offsets and more than 2,700 tons of VOC offsets available within New York.[1] CPV Valley is currently in discussions relating to NO_x and VOC offsets and will identify the source of offsets prior to issuance of a draft permit.

3.5.4 Compliance Status of CPV Affiliated New York Facilities

CPV does not own, but manages the Athens Generating Plant, a 1080 MW natural gas combined cycle plant located in Athens, Greene County, New York. At the present time, the Athens facility is operating in full compliance with Title III (Environmental Conservation).

3.5.5 Analysis of Alternatives

Based upon the NYSDEC requirements at 6 NYCRR 231-2.4(a)2(ii), the Project is required to conduct an analysis of “alternative sites, sizes, production processes and environmental control techniques for the proposed Facility, which demonstrates that the benefits of the proposed Facility significantly outweigh the environmental and social costs” imposed as a result of the proposed construction. Alternative emission control technologies are identified and evaluated for this high-efficiency advanced technology combined cycle equipment in the BACT and LAER control technology analyses of Section 4 of this document, and demonstrations are provided that the proposed technology and controls satisfy BACT/LAER criteria.

3.5.5.1 Project Background

The Facility will consist of two F-Class combustion turbines with supplementary-fired HRSGs. The turbines will employ selective catalytic reduction to control nitrogen oxide emissions and an oxidation catalyst to control carbon monoxide and VOC emissions; the exhaust from each turbine will be directed to a dedicated 275-foot stack (above grade level) with a 19-foot diameter flue. The turbine will fire natural gas as the primary fuel with the ability to fire ULSD for a maximum amount equivalent to 720 hours per year at full load. Being a highly efficient

[1] The ERC Registry is available on the Internet at http://www.dec.ny.gov/chemical/8946.html.

combined cycle facility, the Project will displace less efficient plants with higher emission rates. The projected reductions in sulfur dioxide, nitrogen oxides, and carbon dioxide promote the State's policies to reduce pollution and greenhouse gases. In addition to the air quality benefits of this displacement, the Project will reduce New York State's reliance on oil. It is the policy of the United States and New York State to promote energy efficiency and the use of fuels other than oil to enhance our national security and reliability.

Several vendors were contacted and turbine performance specifications were obtained specific to the size of the Project 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 Project site location and recognized the Project would be affected by the following:

- The Project site area within New York is a non-attainment area for ozone and PM-2.5;
- The Project would result in an emissions increase of greater than 100 tons of NO_x and 50 tons of VOC and would be subject to non-attainment requirements;
- The Facility would be considered a major PSD source;
- The Facility would need to comply with LAER provisions; and
- Emissions offsets for NO_x and VOC would need to be acquired.

Based upon this assessment and the time allotted for equipment procurement and construction, a decision was made to proceed with the licensing of two F-Class combustion turbine combined cycle units.

3.5.5.2 Analysis of Alternatives Results

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

3.5.5.2.1 Alternative Sites

CPV considered various sites throughout New York State for potential development of an energy center such as CPV Valley. However, through careful screening and analysis, the Project site in Wawayanda was determined to be the preferred site. CPV's screening process evaluated sites based on various technical, infrastructure, environmental, and economic attributes. The screening criteria used by CPV in evaluating potential sites included:

- Proximity to Electric Transmission System
- Proximity to Natural Gas Supply

- Site Size (Site Buffer)
- Zoning
- Transportation Infrastructure
- Water Supply and disposal Availability
- Wetlands & Water Bodies
- Proximity to Sensitive Receptors
- Topography
- Emissions and Environmental Climate

Based on these criteria, CPV evaluated alternate sites for feasibility using a phased approach. First, by performing a high level review, potential sites were ranked based on the criteria mentioned above. Those sites that were identified as having a fatal flaw were removed from consideration. A second and more detailed review was performed for the remaining sites. This second review required significant technical and environmental review and consideration. As fatal flaws were identified with particular sites, those sites were removed from consideration.

CPV's screening process identified several sites. Through the screening process described above, the Wawayanda site was identified as the preferred site. An alternative site in Stoney Point, New York was also considered and optioned. Although the Stoney Point site was optioned, it was dropped from consideration due to a fatal flaw that was later identified during the technical analysis.

As a result, the site in Wawayanda was identified as the preferred site, since it contains a number of features that make it ideal for hosting a combined-cycle power plant. The Project site attributes include:

- Proximity to interconnects for electric power transmission, water supply, and wastewater discharge;
- Sufficient acreage to allow CPV Valley to integrate a buffer to adjacent land uses and provide for on-site and nearby construction staging, as well as ample wetland mitigation;
- Location within an area designated by the Town of Wawayanda approved Comprehensive Plan for industrial development;
- Optimum site access due to proximity to I-84, Route 17M and Route 6;
- Favorable air dispersion characteristics and a relatively isolated location that will mitigate potential visual and noise impacts; and
- Proximity to the Middletown publicly owned treatment works (POTW), which will supply treated effluent for Project process water needs and accept Project wastewater discharge.

There are no suitable alternate sites under CPV Valley's control. Therefore, it is concluded that no alternative is preferable for the Project.

3.5.5.2.2 Environmental Considerations

The use of modern combined cycle technology, as represented by the selected turbine, inherently promotes the efficient utilization of fuel for electric generation. Increased combustion efficiency and the use of proven combustion turbine technology favorably affects the cost of generating electricity and reduces the environmental impacts associated with older generating plants combusting residual oil, coal, and other fuels that do not burn as clean as natural gas. The Project has been designed to meet the objective of providing environmentally safe electricity. CPV Valley believes that the Project meets and exceeds environmental commitments for the following reasons:

- The use of DLN combustors, water injection, and an SCR system as LAER for control of NO_x;
- The use of an oxidation catalyst to control CO and VOC emissions;
- The oxidation catalyst will also have the potential of reducing organic hazardous air pollutant (HAP) emissions in the same manner as it will be reducing VOC emissions;
- Utilization of aqueous ammonia as opposed to anhydrous ammonia for the SCR system;
- Advanced technology combustion turbine and combustion controls to minimize incomplete combustion, thereby reducing emissions of NO_x, VOC, CO, and PM/PM-10/PM-2.5;
- The use of clean burning natural gas as the primary fuel and ULSD as a backup fuel to minimize impacts of SO_2 and PM/PM-10/PM-2.5 (emissions of PM/PM-10/PM-2.5 are minimized by low-sulfur natural gas and ULSD since less SO_3 is available to react with byproducts of the SCR and form ammonia bisulfate particulate); and
- State of the art combustion controls and continuous emissions monitoring systems (CEMS).

3.5.6 Public Need for the Project

Public agencies and private corporations, in their consideration of specific proposals to address growing demands for electrical energy, must evaluate a number of associated needs. Foremost among these are the need to ensure system efficiency and reliability, the need to generate or supply power at a reasonable cost, and the need to provide the required power in an environmentally responsible manner.

A number of features, each of which will be promoted through development of the Project, affect the efficient and reliable supply of power to the electrical system. One important factor, particularly during periods of high demand, is the availability of capacity to meet that demand. The development of new capacity will provide for this requirement.

Another factor contributing to system reliability is the siting of sources of supply and associated transmission facilities in proximity to demand centers. Siting of generating capacity near the users minimizes the inherent losses during transmission.

Use of modern combined cycle technology promotes the efficient utilization of fuel for electric generation. Increasing fuel efficiency favorably affects the cost of generating electricity and reduces environmental impacts associated with other generation methods such as coal-fired or residual oil-fired plants. The proposed Project has been designed to meet the objective of providing reliable, efficient, economical and environmentally safe electricity.

The need for additional power generating resources in New York and the Lower Hudson Valley in particular is addressed in The New York Independent System Operator (NYISO) 2008 Comprehensive Reliability Plan. The NYISO, while acknowledging some success, still predicts a need for additional energy production capacity in order to meet New York's growing energy needs:

- The NYISO determined that 1,050 MW of new generation should be added in the Lower Hudson Valley (Zone G).
- The NYISO stated that locating more resources in the Lower Hudson Valley is important to satisfy local reliability needs.
- Looking beyond reliability requirements, NYISO explains that a newer, more efficient fleet of generating facilities would produce orders of magnitude improvement in terms of emissions reductions.

3.5.7 Benefits of the Proposed Facility

The purpose of the proposed 630-MW CPV Valley Energy Center Project is to provide economical, reliable, efficient and environmentally safe electricity to residents of The Lower Hudson Valley. According to documents published by the New York State Department of Public Service (NYSDPS), New Yorkers have been paying electric prices well above the national average. In addition to higher residential rates, it has been suggested that high electric rates have been a factor hindering economic development, causing businesses to leave the state, or not to locate or expand in New York, potentially resulting in the loss of jobs.

The New York Public Service Commission (NYPSC or Commission) regulates privately-owned electric, cable, gas, steam, telecommunications, and water utilities in New York State. The commission's mandate is to ensure that consumers receive safe and reliable utility service at reasonable rates with the least adverse effect on the environment.

On May 20, 1996, the Commission issued Opinion No. 96-12 which established the framework for a competitive electric industry in the State of New York. The goal of the Order was reduced prices through an "open and fair" retail marketplace with increased consumer choice of electric providers. The Commission stated:

> there should be effective competition in both the generation and energy services sectors. We expect enough players to participate so that no single provider of service dominates the market as a whole or any part of it, controls the price of electricity, or limits customer options. An effective market requires many buyers and sellers.

The proposed Project will provide competitive electric generation and improve reliability of power generation and supply within the region.

The Project will bring a number of economic benefits to the residents of Orange County. Besides improving the efficiency with which citizens of New York meet their energy needs, the beneficial economic impacts include:

- The proposed Project will pay substantial taxes (or payments in lieu of taxes) associated with improvements to the property, sales taxes on locally purchased items supporting the operation of the Facility, and income taxes. These taxes will benefit the local school district, the Town of Wawayanda, Orange County, and the State of New York.

- Construction of the CPV Valley Energy Center will employ an average workforce of approximately 400 employees, during a 24-month construction period. The Project will have a minimal impact on the municipal services supported by the tax dollars it pays.

- The proposed CPV Valley Energy Center will result in the creation of approximately 25 permanent, highly skilled jobs with a substantial payroll.

- CPV Valley Energy Center results in a net environmental impact far less than the impacts associated with the equivalent amount of power 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 described in this section of this document.

3.6 NO_x SIP Call (NO_x Budget Program) Requirements

In October, 1998, USEPA finalized the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone." (commonly called the NO_x SIP Call.) The NO_x SIP call was designed to mitigate significant transport of NO_x, one of the precursors of ozone. For those States opting to meet the obligations of the NO_x SIP call through a cap and trade program, USEPA included a model NO_x Budget Trading Program rule (Part 96). This trading program was developed to facilitate cost effective emissions reductions of NO_x from large stationary sources. Part 96 provides sources with a complete trading program including provisions for applicability, allocations, monitoring, banking, penalties, trading protocols, and program administration. States choosing to participate in the NO_x Budget Trading Program have the flexibility to modify certain provisions within the model rule.

Regulations covering New York State's implementation of the NO_x SIP Call have been codified in Parts 204 and 237. 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. Quantities of 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 have these allowances provided until the new Facility is able to establish a 3-year baseline of operations.

A Facility subject to the provisions of the NO_x SIP Call Program must identify an Authorized Account Representative (AAR) and establish a NO_x Allowance Trading Account. The AAR is responsible for maintaining the Facility account, including ensuring that enough allowances are in place in time to meet the regulatory deadline. Shortfalls in the account can be made up by either transferring allowances from another Facility account or outright purchase of the needed allowances.

In order to ensure that NO_x emissions do not exceed allowances, budget sources are required to monitor and report NO_x emissions during the control period of each year. The preferred method of emissions monitoring includes utilization of sophisticated CEMS, as approved under 40 CFR 75 (the Acid Rain Program). Although Part 75 need not be followed for the NO_x SIP Call program (the program allows for monitoring at a "near Part 75" level of effort), the issue becomes moot given that the Project will need to comply with Part 75 under the Acid Rain program (see Section 3.7). Any budget source currently subject to Part 75 monitoring must maintain and use that monitoring for emissions tracking under the NO_x SIP Call. The NO_x SIP Call permit application for this Project is included in Appendix D.

3.7 Federal Acid Rain Regulations

Title IV of the CAAA required USEPA 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 market-based part of the program, existing units are allocated SO_2 allowances by the USEPA. Once allowances are allocated, affected facilities may use their allowances to cover emissions, or may trade their allowances to other units under a market allowance program. In addition, applicable facilities are required to implement continuous emissions monitoring (CEM) for affected units.

3.7.1 Monitoring Requirements

The CEM requirements of the Acid Rain Program include: an SO_2 concentration monitor, a NO_x concentration monitor, a CO_2 concentration monitor, a volumetric flow monitor, an opacity monitor, a diluent gas (O_2) monitor, and a computer-based data acquisition and handling system for recording and performing calculations. Title IV Acid Rain NO_x emission limits have only been established for coal-fired utility boilers at this time. Therefore, the proposed Project is not subject to the NO_x emission limitations, although NO_x (and CO_2) needs to be continuously monitored to satisfy agency "data gathering" requirements. CO_2 emissions, as measured by an O_2 diluent monitor, are an acceptable source of data for the Acid Rain program. The Acid Rain program allows for alternate methods of SO_2 monitoring for facilities that fire only low-sulfur gaseous fuels or primarily fire low-sulfur gaseous fuels (i.e., at least 90% of the unit's average annual heat input during the previous three calendar years and for at least 85% of the annual heat input in each of those calendar years). An allowable alternate method would include fuel flow monitoring and mass balance reconciliation of SO_2 emissions from fuel sulfur content.

Implementation of the Acid Rain Program by the USEPA has been broken into two phases. Phase I of the program required 110 sources identified in the Clean Air Act Amendments of 1990 (CAAA) to operate in compliance by January 1, 1995. Facilities identified in Phase II of the program were required to operate in compliance by January 1, 2000. Additionally, existing Phase II facilities were required to install and operate a certified CEM system by January 1, 1995. The CPV Valley Energy Center is subject to the Acid Rain Program based upon the provisions of 40 CFR 72.6(a)(3) since the turbines are considered utility units under the program definition and do not meet the exemptions listed under paragraph (b) of this Section. The Project will be subject to Phase II Acid Rain requirements and CPV Valley will be required to submit an acid rain permit application by the 24 months prior to the date on which the unit expects to begin service as a generator. The Acid Rain permit application for this Project is included in Appendix D.

3.7.2 Calculation of SO_2 Allowances Required

Based upon the regulatory impact analysis presented above, CPV Valley Energy Center will be required to obtain SO_2 allowances in order to comply with the requirements of the Acid Rain regulations as promulgated in 40 CFR 72 and 40 CFR 73. 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 USEPA by January 30 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 75.

After the January 30 deadline and the recording of the final submitted transfers, USEPA 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 USEPA as excess emission offsets. Unless otherwise provided in an offset plan, USEPA deducts allowances from the compliance subaccount in an amount equal to the excess emissions.

The Project will be required to obtain SO_2 allowances. Based upon potential emission calculations presented in Appendix B, the Project will be required to purchase no more than 42 tons of allowances per year.

3.7.3 Sources of Allowances

In addition to annual allocations from the USEPA, allowances are also available upon application to three USEPA 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% 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 USEPA. 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 Project) will not be allocated allowances. Instead, they will have to purchase allowances from the market or from the USEPA 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 Project.

3.7.4 Phase II Acid Rain Permit Application

The Phase II Acid Rain permit application for this Project is included in Appendix D.

3.8 CO_2 Budget Trading Program

The CO_2 Budget Trading Program is a mandatory cap-and-trade program to reduce greenhouse gas emissions as part of the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States. RGGI is composed of individual CO_2 Budget Trading Programs in each of the ten participating states. These ten programs are implemented through state regulations, based on a RGGI Model Rule, and are linked through CO_2 allowance reciprocity. Regulated power plants will be able to use a CO_2 allowance issued by any of the ten participating states to demonstrate compliance with the state program governing their facility. Taken together, the ten individual state programs will function as a single regional compliance market for carbon emissions. Under this program, New York (and other participating states) will stabilize power sector CO_2 emissions at the capped level through 2014. The cap will then be reduced by 2.5 percent in each of the four years 2015 through 2018, for a total reduction of 10 percent Sources will need to acquire, from auctions or directly from the NYSDEC, one allowance (permit to emit CO_2) for every ton of CO_2 that they emit.

3.9 Clean Air Interstate Rule (CAIR) Applicability

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). This rule, which covers 28 eastern states and the District of Columbia, requires reductions in emissions of NO_x and SO_2 from large fossil fuel fired electric generating units using a cap and trade system. The rule is set up in several phases with the first phase on NO_x reductions to come by 2009 and the first phase of SO_2 reductions by 2010. The rule sets up both an annual emissions budget and an ozone season emission budget for each state. States allocate emissions allowances to power plants which can either control emissions to stay within their allowance allocations or purchase additional allowances from other sources with the CAIR region. On July 11, 2008, the D.C. Circuit vacated CAIR. On September 25, 2008, EPA petitioned for a rehearing of the CAIR decision. The Court has 30 to 45 days to decide whether or not to rehear the case. Because EPA has requested the rehearing, the decision vacating the CAIR program is stayed and technically, the CAIR rule remains in effect.

In the air permit pre-application meeting, NYSDEC advised CPV Valley that it would not need to address the state's CAIR rule, however, because the state CAIR rule is technically in effect, the Project is submitting a CAIR permit application and has included it in Appendix D.

3.10 Maximum Achievable Control Technology (MACT) Applicability

Current USEPA AP-42 emission factors, other emission factors and correspondence from the Class-F combustion turbine vendor were reviewed in determining if the Project was subject to MACT. Based upon potential emissions calculations, the maximum single hazardous air pollutant emissions will be less than the 10 tons/year MACT applicability threshold (for a single pollutant). In addition, combined hazardous pollutant emissions will likewise be below the applicability threshold of 25 tons/year. Therefore, the MACT requirement does not apply to the proposed Project.

3.11 Section 112(r) Applicability

Aqueous ammonia will be used as the reducing agent in the Project's SCR system for controlling NO_x emissions from the combustion turbine/duct burner. The NO_x reduction achieved by the SCR system is affected by the ratio of ammonia (NH_3) to NO_x. Section 112(r) of the Clean Air Act and the USEPA's Risk Management Program regulations (40 CFR Part 68) require modeling a catastrophic release of any stored ammonia at 20% concentration or above in order to ensure the protection of the off-site public. Furthermore, based on the "general duty" clause of Section 112(r), such analyses can be required even if the aqueous ammonia solution is diluted below 20%. CPV Valley proposes to store aqueous ammonia at a maximum ammonia concentration of 19% as the means of complying with Section 112(r).

Table 3-1: National and New York Ambient Air Quality Standards, PSD Increments and Significant Impact Levels ($\mu g/m^3$)					
Pollutant	**Averaging Period**	**NAAQS**	**NYAAQS**	**PSD Increments Class II**	**Significant Impact Level**
Sulfur Dioxide (SO_2)	3-Hour	1,300[1]	1,300[1]	512[1]	25
	24-Hour	365[1]	365[1]	91[1]	5
	Annual	80[2]	80[2]	20[2]	1
Nitrogen Dioxide (NO_2)	Annual	100[2]	100[2]	25[2]	1
Particulate (PM-10)	24-Hour	150[3]	150[3]	30[1]	5
	Annual	50	50	17[1]	1
Fine Particulate (PM-2.5)	24-Hour	35	N/A	N/A	N/A
	Annual	15	N/A	N/A	N/A
Total Suspended Particulate (TSP)	24-Hour	N/A	250[5]	N/A	N/A
	Annual	N/A	75[6]	N/A	N/A
Carbon Monoxide (CO)	1-Hour	40,000[1]	40,000[1]	N/A	2,000
	8-Hour	10,000[1]	10,000[1]	N/A	500
Ozone (O_3)	1-Hour	235[5]	235[51]	N/A	N/A
	8-hour	150	160	N/A	N/A
Lead (Pb)	Quarterly	1.50[2]	N/A	N/A	N/A
Gaseous Fluorides (as F)[7]	12-Hour	N/A	3.70[2]	N/A	N/A
	24-Hour	N/A	2.85[2]	N/A	N/A
	1-Week	N/A	1.65[2]	N/A	N/A
	1-Month	N/A	0.80[2]	N/A	N/A
Beryllium	1-Month	N/A	0.01[2]	N/A	N/A
Hydrogen Sulfide[7]	1-Hour	N/A	14[2]	N/A	N/A

[1] Not to be exceeded more than once per year.
[2] Not to be exceeded.
[3] Fourth highest concentration over a three year period.
[4] Average of three annual average concentrations.
[5] Not to be exceeded more than once per year on average. Applies only in limited areas.
[6] Geometric mean of the 24-hour average concentrations over 12-month period.
[7] Pollutant will not be emitted from the Project.

Source: 40 CFR 50; 6 NYCRR 257; 40 CFR 52.

Table 3-2: PSD and Non-Attainment NSR Significant Emission Rates and Project Potential Emission Rates				
Pollutant[1]	**PSD Significant Emission Rates (tons/year)**	**NNSR Major Source Thresholds (tons/year)**	**Annual Facility Emissions (tons/year)**	**PSD/NSR Triggered? (Yes/No)**
Carbon Monoxide	100	N/A	344	Yes
Sulfur Dioxide	40	100	42	Yes
PM	25	N/A	95	Yes
PM-10	15	N/A	95	Yes
PM-2.5	10	100	95	No
Nitrogen Oxides	40[2]	100[3]	187	Yes
VOC	40	50[3]	65	Yes
Sulfuric Acid Mist	7	N/A	13	Yes
Lead	0.6	N/A	0.02	No

[1] Regulated substances not emitted by the proposed Project, fluorides and total reduced sulfur, have not been included in the table.
[2] PSD threshold is for NO_2.
[3] Ozone non-attainment major source threshold.

Source: TRC Environmental, 2008; 6 NYCRR 231-2 and 40 CFR 52.21 (b)(23)(i).

Table 3-3: USEPA Significant Monitoring Concentrations		
Pollutant	**Averaging Period**	**Significant Monitoring Concentration (μg/m^3)**
Carbon Monoxide	8-hour	575
Nitrogen Dioxide	Annual	14
Sulfur Dioxide	24-Hour	13
Particulates (PM & PM-10)	24-hour	10
Lead	3-month	0.1

[1] SMCs also exist for other pollutants that will not be emitted by the Project (fluorides, total reduced sulfur, hydrogen sulfide, and reduced sulfur compounds.

Source: 40 CFR 52.21(i)(8)(i).

Table 3-4: Calculation of Offsets			
Non-Attainment Pollutant	**Potential Emissions (tons/year)**	**Proposed Offset Ratio**	**Required Offsets (Rounded Up)[1]**
Nitrogen Oxides	187	1.15:1	216
Volatile Organic Compounds	65	1.15:1	75

Table 3-5: New York State Facilities Owned, Operated By or Affiliated with CPV Valley, LLC in Support of Compliance Review	
Facility Name	Athens Generating Plant
Address	9300 US RTE 9W
Municipality & County	Athens, Greene County
Compliance Status	In compliance with Title III (Environmental Conservation)
Relationship to Applicant	CPV through its affiliate manages the Athens Generating Plant under contract to the plant's owner.

Source: CPV Valley, LLC, 2008.

4.0 CONTROL TECHNOLOGY ANALYSIS

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 designated by USEPA as attainment or unclassifiable for a particular pollutant, then new major sources would require permitting under the PSD program, including a BACT demonstration for pollutants emitted in quantities greater than the regulatory thresholds. However, if an area is designated by USEPA as non-attainment for a given pollutant and the major 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. Non-attainment NSR requires the application of LAER technology and the requirement to obtain emission offsets.

A control technology analysis has been performed for the proposed Facility based upon guidance presented in the draft USEPA Guidance Document *New Source Review Workshop Manual*, (October, 1990). PSD and non-attainment NSR requirements for each pollutant were defined in Section 3 above.

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 additional NYSDEC requirements for emissions from equipment included in this permit application.

4.2.1 PSD Pollutants Subject To BACT

Pollutants subject to PSD review are subject to a BACT analysis. 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 considerations.[2] The proposed Facility is considered a "major" source for PSD purposes since potential emissions exceed major source thresholds. Therefore, individual regulated pollutants are subject to BACT requirements if potential emissions exceed the significant emission rates presented in 40 CFR 52.21(b)(23) in a PSD (attainment) area, as presented in Table 3-2. Based upon these criteria, NO_x, CO, PM/PM-10, SO_2, and H_2SO_4 are all subject to BACT requirements. Since the area is designated attainment for NO_2, NO_x emissions are subject to BACT, as well as the more stringent LAER requirements under the ozone non-attainment provisions. Since the LAER requirements are generally at least as stringent as BACT, the LAER analysis will satisfy the technology requirements for NO_x.

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 more stringent of (1) the most stringent emission limitation which is achieved in practice by the class or category of source or (2) the most stringent emission limitation contained in the applicable State Implementation Plan (unless such emission rate is demonstrated not to be achievable), whichever is the more stringent.[3] 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 potential emissions of individual pollutants exceed area-specific emission thresholds. Emissions of NO_x and VOC are subject to LAER requirements since they exceed the non-attainment thresholds of 100 tons per year and 50 tons per year, respectively.

4.2.3 Emission Units Subject to BACT or LAER Analysis

For a facility subject to a BACT or LAER analysis, each pollutant emitted in amounts greater than the significant emission rate (Table 3-2) is subject to the prescribed level of control technology review for each emission unit from which the pollutant is emitted. For the proposed Project, the sources responsible for the majority of the Facility's emissions will be the combustion turbines, duct burner, and auxiliary boiler. Therefore, the primary focus of the BACT and LAER analyses presented in the following sections is on these principal emission units. Evaluation of potential controls for the Fuel gas heaters is conducted consistent with the unit's proposed small annual emission levels, and potential controls for the emergency diesel generator and emergency diesel fire pump are evaluated with consideration to the unit's limited operation.

[2] The Federal definition may be found at 42 USC 7479(3), and the New York State definition at 6 NYCRR 200.1(j).

[3] The Federal definition may be found at 42 USC 7501, and the New York State definition at 6 NYCRR 200.1(ak).

4.3 Approach Used in BACT Analysis

As previously stated, BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of energy, economic and environmental factors. In a BACT analysis, the energy, environmental, and economic factors associated with each alternate control technology are evaluated, as necessary, in addition to the benefit of reduced emissions that the technology would provide. The BACT analyses presented here consist of up to five steps for each pollutant, as outlined below.

4.3.1 Identification of Technically Feasible Control Options

The first step is identification of available technically feasible control technology options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements that would prevail in the absence of BACT decision-making, such as RACT or NYSDEC emission standards. After elimination of technically infeasible control technologies, the remaining options are ranked by control effectiveness.

If there is only a single feasible option, or if the applicant is proposing the most stringent alternative, then no further analysis is required. If two or more technically feasible options are identified, the next three steps are applied to identify and compare the economic, energy, and environmental impacts of the options. Technical considerations and site-specific sensitive issues will often play a role in BACT determinations. Generally, if the most stringent technology is rejected as BACT, the next most stringent technology is evaluated, and so on.

In order to identify options for each class of equipment, a search of the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) has been performed. Individual searches have been performed for each pollutant (subject to BACT/LAER) emitted from each emissions unit. The most recently issued permits for combustion turbines in New York State and others not yet on the RBLC were also analyzed. Results of the RBLC and other recent permits search are summarized in Appendix E.

4.3.2 Economic (Cost-Effectiveness) Analysis

This analysis consists of estimation of costs and calculation of the cost-effectiveness of each control technology, on a dollar per ton of pollution removed basis. Annual emissions of an option are subtracted from base case emissions to calculate tons of pollutant controlled per year. The base case may be uncontrolled emissions or the maximum emission rate allowable without

BACT considerations that would generally correspond to an NSPS or RACT level. Annual costs, in dollars per year, are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost-effectiveness ($/ton) of an option is simply the equivalent annual cost ($/yr) divided by the annual reduction in emissions (ton/yr).

Note that no economic analysis is required if either the most effective option is proposed or if there are no technically feasible control options.

4.3.3 Energy Impact Analysis

Two forms of energy impacts that may be associated with a control option can normally be quantified. Increases in energy consumption resulting from increased heat rate may be shown as incremental Btu's or fuel consumed per year. Also, the installation of a control option may reduce the output and/or reliability of the proposed equipment. This reduction would also result in loss of revenue from power sales.

4.3.4 Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutant being emitted. Increases or decreases in emissions of other criteria or non-criteria pollutants may occur with some technologies, and should also be identified. Non-air related impacts, such as solid waste disposal and increased water consumption/ treatment, may be an issue for some projects and control options. CPV Valley has avoided such non-air impacts by utilizing inlet air cooling and using clean burning fuels.

4.3.5 BACT Proposal

The determination of BACT for each pollutant from a given emission unit is based on a review of the above-listed impact categories and the technical factors that affect feasibility of the control alternatives under consideration. The methodology described above is applied to the proposed Project for the pollutants specified above.

4.4 LAER/BACT Analysis for Nitrogen Oxides

This section presents LAER and BACT determinations for control of NO_x emissions from the combined cycle combustion turbines and duct burners, the auxiliary boiler, the fuel gas heater and the emergency diesel engines. For each type of equipment, alternative control technologies are evaluated and existing permit limits for units in the same source categories are identified.

As previously discussed, a LAER determination for a source category is based upon the more stringent of either 1) the most stringent emission limitation contained in the SIP for such class or category of source or 2) the most stringent emission limitation achieved 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 final 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 limit, a search of the RBLC and recently issued applicable air permits was performed. The results of the search are presented in Section 4.4.1 and Appendix E.

The formation of NO_x in combustion units 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 by installing post-combustion controls. Section 4.4.2 provides a technical description of NO_x control techniques for all the applicable equipment and the relative availability and suitability for the proposed Project.

4.4.1 Review of NO_x RBLC Database

4.4.1.1 Combined Cycle Combustion Turbines and Duct Burners

The search of the RBLC and available permits identified over 300 natural gas-fired combined cycle combustion turbine projects with NO_x emission limits ranging from 2 to 102 ppm with the majority of the NO_x emission limits at or below 9 ppm. Thirty-three of these projects are limited to the lowest achievable emission rate (LAER) of 2 ppm and all use selective catalytic reduction in addition to dry low-NO_x (DLN) or low-NO_x burner (LNB) technology. CPV Valley is aware that at least four of these projects have demonstrated compliance with their 2 ppm NO_x emission limits, most notably the KeySpan Ravenswood Cogeneration Project located in Queens, New York. Five of these projects, including the KeySpan Ravenswood Cogeneration Project, have additional permitted NO_x emission limits above 2 ppm for alternative operating modes when employing either duct firing or for oil-fired operation with steam injection.

In general, LAER determinations have focused on the level that can be achieved in the primary operating mode (typically gas-fired 100% load), with NO_x levels being set for alternative modes (oil, supplementary firing, part load, etc.) at the levels that result from application of the same degree of control used to achieve LAER for the primary mode.

In the event that natural gas is unavailable, the Project will burn ULSD as a backup fuel. Operation on ULSD will be limited to a fuel consumption amount equivalent to 30 days per year or 720 hours per year of full load operation for each turbine. A review of the RBLC and available permits identified approximately 80 fuel oil-fired combined cycle combustion turbine projects with NO_x emission limits ranging from 5 to 97 ppm with the majority of the NO_x emission limits at or below 15 ppm. The Sam Rayburn Generation Station in Nursery, Texas is listed in the RBLC as having a NO_x emission limit of 5 ppm. Additionally, the Towantic Energy, LLC, the Lake Road Generating Company, L.P. and the PDC El Paso Milford, LLC facilities are listed in the RBLC as having NO_x emission limits of 5.9 ppm. CPV Valley is unable to verify if any of these four facilities have achieved these emission limits in practice. The next lowest permitted NO_x emission limit of 6 ppm has been assigned to nine fuel oil-fired combined cycle projects, two of which are believed to be operating in compliance with the 6 ppm NO_x limit. The two out of nine permitted projects located in New York State are the Astoria Energy, LLC Project located in Queens, New York and the TransGas Energy Project which received a draft air permit from the NYSDEC on June 4, 2003 but has not yet been constructed.

4.4.1.2 Auxiliary Boiler

The most stringent NO_x emission permit limit shown in the RBLC and search of recent air permits for natural gas-fired boilers between 10 and 100 mmBtu/hr in size is 0.0006 lb/mmBtu for a boiler at the Mapee Alcohol Fuel, Inc. facility in Moore County, Texas. This facility was permitted in 1981 and its operation cannot be verified. The next lowest permitted NO_x emission limit for boilers of a similar size firing natural gas appear at four facilities with NO_x emissions listed between 0.0085 and 0.0090 lb/mmBtu, which all correspond to a permitted NO_x emission level of 7 ppm. All of these boilers are believed to be operating and all employ SCR to reduce NO_x emissions. Next, there are five listed facilities with boilers firing natural gas and all are permitted at 0.011 lb/mmBtu, which corresponds to a permitted NO_x emission level of 9 ppm. Four out of these 5 listed facilities are believed to be operating and 3 of these boilers are achieving their 0.011 lb/mmBtu NO_x emission level with only low-NO_x burners, without SCR controls.

4.4.1.3 Fuel Gas Heaters

The most stringent NO_x emission permit limit found in the RBLC and available permits for natural gas-fired dew point/fuel/efficiency/recuperator heaters is 0.036 lb/mmBtu for an 8.4 mmBtu/hr fuel gas heater located at the Greater Des Moines Energy Center in Des Moines, Iowa and 3 x 4.6 mmBtu/hr gas heaters at the Ocean Peaking Power facility located in Lakewood Township, New Jersey. In past discussions with the Greater Des Moines Energy Center, it was determined that the permitted NO_x emission rate of 0.036 lb/mmBtu is not based on a vendor guarantee but rather represents an engineering calculation estimate. The PSD permit for the Greater Des Moines Energy Center fuel gas heater does not require compliance testing with any permitted emission limits. Since this 0.036 lb/mmBtu NO_x emission limit cannot be verified as achieved in practice for this facility, it is not believed to represent LAER for the Project. The Ocean Peaking Power facility gas heaters permitted NO_x emission rate of 0.036 lb/mmBtu is based on a vendor guarantee. This heater utilizes a low-NO_x forced draft burner to reduce emissions of NO_x.

4.4.1.4 Emergency Diesel Engines

The most stringent NO_x emission permit limit shown in the RBLC database for an emergency diesel fire pump is 1.20 lb/mmBtu at the AES Wolf Hollow, LP facility in Hood County, Texas. The lowest NO_x emission limit for a fire pump that is believed to be operating in compliance with its NO_x emission limit is for a fire pump located at the LSP Cottage Grove, L.P. facility with NO_x emissions limited to 1.85 lb/mmBtu.

The most stringent NO_x emission permit limit found in the RBLC database for an emergency diesel generator is 0.291 lb/mmBtu for a 2.3 MW emergency black start engine at the Nearman Creek Power Station in Kansas. It is unknown whether the facility is operating in compliance. The most recently permitted emergency generator similar in size to the one proposed for the Project is for the Creole Trail Terminal in Louisiana with a NO_x limit of 2.28 lb/mmBtu.

4.4.2 Identification of NO_x Control Options and Technical Feasibility

The following sections detail the options that were identified for controlling NO_x emissions from the combined cycle combustion turbines and duct burners, auxiliary boiler, fuel gas heaters and emergency diesel engines. The technical feasibility of each option is also discussed.

4.4.2.1 Combined Cycle Combustion Turbines and Duct Burners

The following control technologies for NO_x were evaluated: Lean Burn Combustion, Selective Catalytic Reduction, Selective Non-Catalytic Reduction, XONON™ and SCONO$_x$™.

Lean Burn Combustion – Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel and in the combustion zone, with additional air introduced downstream. 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. Thus, 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.

Selective Catalytic Reduction (SCR) – SCR is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine/duct burner. 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 flue gas 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 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/duct burner. The most common configuration is a "honeycomb" design. Ammonia is then fed and mixed into the combustion gas stream 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 standard base metal catalysts is between 400 and 800°F. Since SCR's effective temperatures are below the turbine exit temperature and above the stack temperature, the catalyst must be located within the HRSG.

An undesirable side-effect of SCR is the potential formation of ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$), referred to as ammonium salts, which are corrosive and can stick to the heat recovery surfaces, duct work, or stack at low temperatures and results 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. Use of low sulfur fuels minimizes the formation of SO_3 and the subsequent formation of these ammonium salts.

Selective Non-Catalytic Reduction (SNCR) – SNCR is another method of post-combustion control of NO_x emissions. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injection location and temperature to achieve proper reagent/flue gas mixing for optimum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x removal efficiency. The optimum temperature range for ammonia injection is 1,500° to 1,900°F. The NO_x removal efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions, also referred to as "slip". Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the Project's combined cycle combustion turbine unit is between 200 – 300°F, which is significantly less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this LAER analysis.

XONON™ – A newer NO_x control technology has been developed by Catalytica Energy Systems, with the trade name of XONON™. This combustion technology includes a pre-burner, a fuel injection and mixing system, a flameless catalyst module and a flameless burnout zone. The pre-burner starts the turbine and a fuel injection system provides a uniform fuel and air mixture to the catalyst, where a portion of the fuel is combusted at reduced temperature to reduce thermal NO_x emissions. Catalytica has reported NO_x emissions at less than 3 ppm at 15 percent O_2 from test units under 2 MW. The first commercial version of the XONON™ combustion system is operating in a 1.55 MW gas turbine in Santa Clara, CA. This system has demonstrated NO_x emission levels of less than 2.5 ppm.

The XONON™ system is not yet commercially available from Catalytica Energy Systems for turbines of the size proposed for the Project. However, in December 2000 the California Energy Commission approved the construction of a 750-MW facility in Bakersfield, California. The Pastoria Energy Facility (Pastoria) proposed to use the XONON™ system as BACT to control NO_x emissions from three F-class combined cycle combustion turbines. The approval was based on the anticipation that the XONON™ technology will be available by the time installation of the Project components is scheduled. Should XONON™ not be available in time, Pastoria will install SCR to control emissions of NO_x. Calpine completed construction of the Pastoria facility in 2005 and decided to install SCR. To date, XONON™ technology is not commercially available for large combustion turbines.

Based on the fact that the XONON™ technology is not currently commercially available and has not been proven on combustion turbines of the size proposed by the Project, it is not further considered in this analysis.

$SCONO_X$™ – $SCONO_x$™ or Em_x™ is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NO_x, CO and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOC to CO_2 and water, while NO_2 is adsorbed onto the catalyst surface and chemically converted to and stored as potassium nitrates and nitrites. The $SCONO_x$™ potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12-15 minutes in normal service. Each regeneration cycle requires approximately 3-5 minutes. At any point in time, approximately 20% of the 40 to 60 compartments in a $SCONO_x$™ system, would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/adsorption mode (Stone & Webster, *Independent Technical Review – $SCONO_x$™ Technology and Design Review*, February 2000).

Regeneration of the adsorption layer requires exposure of the catalyst to hydrogen gas. In practice, this is accomplished by reforming natural gas with high-pressure steam to produce a gas mixture consisting of methane, carbon dioxide, and hydrogen that is passed over the catalyst beds (Stone & Webster, February 2000). Initial attempts by the developer of the process to create regeneration gases from natural gas and steam within the $SCONO_x$™ catalyst bed (internal autothermal regeneration) failed to produce consistent results; this approach was abandoned in favor of the current offering, which uses an external steam-heated reformer that partially reforms the natural gas to produce the gas mixture that is introduced into the catalyst bed (ABB Environmental, op cit.). The reformation reaction continues to some extent within the catalyst bed due to the presence of steam and the temperature of the catalyst surface, but some methane and VOC from the natural gas remain.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed at the beginning of each regeneration cycle. Proper regeneration of the $SCONO_x$™ catalyst system depends upon the proper functioning and sealing of these sets of dampers approximately 4 times per hour so that an adequate concentration of hydrogen can be maintained in each module to accomplish complete regeneration of the catalyst before the dampers are opened and the compartment is placed back in service.

Because the $SCONO_x$™ catalyst can be "poisoned" or rendered inactive by even the very small amounts of sulfur compounds present in natural gas, a $SCOSO_x$ catalyst bed, intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream, is installed upstream of the $SCONO_x$™ catalyst bed. Like the $SCONO_x$™ catalyst, the $SCOSO_x$ catalyst must be regenerated. Regeneration of the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both; however, the sulfur-bearing regeneration gas for the $SCOSO_x$ catalyst exits the $SCONO_x$™ modules separately from the $SCONO_x$™ regeneration gas to avoid contaminating the $SCONO_x$™ catalyst beds. Both the regeneration gas streams are returned to the gas turbine exhaust stream downstream of the $SCONO_x$™ module (ABB Environmental).

The external reformer used to create the regeneration gases is supplied with steam and natural gas. For one F-class turbine, an estimated 20,000 lbs/hr of 600°F steam is required (this translates to an additional 61,000 gallons per day of water), along with approximately 100 pounds per hour (2.2 mmBtu/hr) of natural gas (ABB Environmental). To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter to remove some of the sulfur-bearing compounds that are added to natural gas to facilitate leak detection (Stone & Webster).

The regeneration cycle time is expected to be controlled using a feedback system based on NO_x emission rates. That is, the higher the NO_x emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for $SCONO_x$™ systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the $SCOSO_x$ and $SCONO_x$™ catalyst beds, and periodic replacement of the catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst is unknown at present. The $SCOSO_x$ catalyst is expected to require washing once per year. The lead (upstream) $SCONO_x$™ catalyst bed is expected to require washing once per year, while the trailing (downstream) $SCONO_x$™ catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take approximately three days for an F-class machine (Stone & Webster) and produce about 360,000 gallons of wastewater. The estimated catalyst life is reported to be 7 washings (Stone & Webster); the guaranteed catalyst life is three years (letter from ABB ALSTOM Power to Bibb & Associates dated May 5, 2000 or "ABB TMP").

Estimates of the control system efficiency vary. ABB Environmental (now ALSTOM Power) has indicated that the $SCONO_x$™ system is capable of achieving a 90% reduction in NO_X; a 90% reduction in CO, to a level of 2 ppm; and an 80%-85% reduction in VOC emissions (ABB Environmental). The VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1-2 ppm range (ABB Environmental). Commercially quoted NO_x emission rates for the $SCONO_x$™ system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction (ABB TMP), to a 1.0 ppm with no averaging period specified (letter from ABB ALSTOM Power to Sunlaw Energy Corporation dated February 11, 2000). The $SCONO_x$™ system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device (ABB Environmental).

To date, $SCONO_x$™ technology has been commercially demonstrated on natural gas and dual-fuel turbine installations presented in the following table:

Turbine & Fuel	Facility	Location	Startup Date	NO_x Permit Limit
5 MW Solar Taurus 60 dual-fuel[1] turbine	Wyeth BioPharma cogeneration facility Unit #2	Andover, MA	September 2003	2.5 ppm (gas) 15.0 ppm (oil)
5 MW Solar Taurus 60 dual-fuel[1] turbine	Montefiore Medical Center cogeneration Facility	Bronx, NY	June 2002	2.5 ppm (gas) 15.0 ppm (oil)
45 MW ALSTOM GTX100 gas turbine	Redding Electric municipal plant	Redding, CA	June 2002	2.0 ppm (gas)
Two 15 MW Solar Titan 130 gas turbines	University of California cogeneration facility	San Diego, CA	July 2001	2.5 ppm (gas)
5 MW Solar Taurus 60 dual-fuel turbine	Wyeth BioPharma cogeneration facility Unit #1	Andover, MA	1999	2.5 ppm (gas) 15.0 ppm (oil)
32 MW GE LM2500 gas turbine	Sunlaw Federal cogeneration facility	Vernon, CA	1996	Actual[2]

[1] Dual-fuel: pipeline natural gas and low-sulfur diesel fuel oil.
[2] Below 2.0 ppm for nearly all of the plant's operating hours in 2000 and 2001, below 1.5 ppm performance for 97% of those operating hours, and below 1.0 ppm for over 90% of the hours.

The performance of SCR and $SCONO_x$™, insofar as NO_x emission levels are concerned, is essentially equivalent. Both technologies have demonstrated the ability to reduce NO_x emissions by at least 90%. The principal differences between the two technologies are associated with whether the low emission levels proposed have been "achieved in practice," cost-effectiveness, and secondary environmental impacts.

$SCONO_x$™ technology has been found to be capable of achieving compliance with permitted NO_x levels of 2.0 and 15.0 ppm for natural gas and fuel oil operation, respectively. The presently available technical information does not support a conclusion that this technology can be proven on an F-class combustion turbine.

LAER for NO_x is considered to be the use of either SCR or $SCONO_x$™ systems to achieve NO_x levels of 2.0 ppm for natural gas firing. SCR has a proven record of consistently achieving low NO_x emission levels in F-class turbines while $SCONO_x$™ does not. The Project proposes to use SCR technology to meet a NO_x level of 2.0 ppm on a 3-hour average basis, which is consistent with LAER requirements for NO_x.

Since $SCONO_x$™ has not been demonstrated in practice on a unit larger than 45 MW and the Project proposes to utilize low-sulfur distillate oil as a backup fuel, the Project would not be a candidate for the use of this technology since it cannot be shown that the sulfur absorption system can accommodate the somewhat increased sulfur loads associated even with ultra low sulfur distillate oil.

4.4.2.2 Auxiliary Boiler

The following control technologies for NO_x were evaluated: Low-NO_x Burners, Flue Gas Recirculation (FGR), SCR and SNCR.

Low-NO_x Burners – Low NO_x burners reduce NO_x through staged combustion. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_x formation. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low-NO_x burners.

Flue Gas Recirculation (FGR) – In an FGR system, a portion of the flue gas is recirculated from the stack to the burner. The recirculated gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions because the recirculated gas reduces combustion temperatures, thus suppressing the thermal NO_x mechanism. FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with specially designed low-NO_x burners capable of sustaining a stable flame despite the increased recirculated gas flow resulting from the use of FGR. Together, low-NO_x burners and FGR are capable of reducing NO_x emissions by 60 to 90 percent.

SCR – Selective Catalytic Reduction (SCR) technology uses ammonia as a reducing agent in the presence of oxygen over a catalyst. The general chemical reaction is:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The process includes an ammonia delivery system and a selective catalytic reaction section. Vaporized ammonia (or urea) is introduced into the flue gas stream via an injection grid located upstream of the catalyst. NO_x emission reductions of 75 to 85 percent have been achieved through the use of SCR. Typically, an SCR requires temperatures in the 550 – 650 ^oF range. The low flue gas temperatures from the auxiliary boiler (typically 350 – 375 ^oF), make it infeasible to apply additional post combustion controls without reheating the boiler exhaust gas.

SNCR – Selective non-catalytic reduction (SNCR) is a post combustion technique that involves injecting ammonia or urea into the exhaust gas at a temperature range of 1,600 and 2,000°F. At this temperature, NO_x and NH_3 react without a catalyst, reducing NO_x to water and nitrogen. Since there is no catalyst, the conversion of NO_x to water and nitrogen is dependent upon the residence time within the optimum reaction temperature window. Adequate mixing of the reducing agent with the exhaust gas is another key to success. NO_x reductions of 25 to 40 percent have been achieved. SNCRs typically require temperatures between 1200 – 1600 °F. The low flue gas temperatures from the auxiliary boiler (typically 350 – 375 °F), make it infeasible to apply additional post combustion controls without reheating the boiler exhaust gas.

4.4.2.3 Fuel Gas Heaters

Based on the results of the RBLC and available permits searches, the only control technology evaluated is Low-NO_x Burners. Add-on controls such as Selective Catalytic Reduction and Selective Non-Catalytic Reduction (SNCR) are considered not considered feasible for the fuel gas heater due to design limitations on geometry as well as the required temperature window not being available without reheating the heater exhaust gas.

Low-NO_x Burners – Low-NO_x burners reduce NO_x through staged combustion. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_x formation. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low-NO_x burners. The proposed forced draft burners are a form of low- NO_x burner technology.

4.4.2.4 Emergency Diesel Engines

USEPA's Alternative Control Techniques (ACT) Document for reciprocating engines lists add-on techniques such as SCR, as well as combustion control techniques such as ignition timing retard, for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for small emergency diesel engines that operate less than 500 hours/year. While cost is not a factor that may be considered in LAER determinations, add-on techniques would be ineffective. Since the emergency diesel fire pump and emergency diesel generator will run for limited duration, the SCR would never reach the operating temperature required to remove any substantial NO_x emissions, and thus would provide no benefit. Therefore, add-on controls do not represent NO_x LAER for the emergency diesel engines.

Ignition retard is accomplished in a reciprocating engine by delaying the injection of the fuel into the compressed air in the cylinder. The result is that combustion occurs at lower peak pressures and temperatures. In addition, the duration of the peak pressure and temperatures is shorter than for standard timing of the fuel injection. The lower peak flame temperature and the shorter exposure reduce the formation of NO_x. However, as a result of the reduction in peak pressures and temperatures, ignition retard reduces maximum power output and engine efficiency while increasing emissions (particulates, VOC and CO) and fuel consumption. Vendors no longer recommend this technology for emergency diesel engines, due to the various limitations of ignition retard outweighing its limited effectiveness. Fuel consumption can increase up to 5 percent, while emissions of hydrocarbons and particulates can double. With these factors and the unit's proposed limited operation during emergencies and testing only, ignition retard does not represent NO_x LAER for the emergency diesel fire pump or the emergency diesel generator.

4.4.3 Determination of LAER for NO_x

4.4.3.1 Combined Cycle Combustion Turbines and Duct Burners

CPV Valley proposes DLN during natural gas firing and water injection during oil firing. These technologies will be used in combination with SCR, in order to achieve LAER for NO_x emissions from the Project's combined-cycle units. The proposed NO_x emission limit for the turbine is 2.0 ppm (3-hour average) while firing natural gas with and without duct firing and 6.0 ppm (3-hour average) when firing ULSD.

4.4.3.2 Auxiliary Boiler

Based upon the analysis presented above, the Project is proposing to use flue gas recirculation in combination with low-NO_x burners to achieve NO_x emissions of 0.045 lb/mmBtu.

4.4.3.3 Fuel Gas Heaters

Based upon the analysis presented above, the Project is proposing to use forced draft LNB for the natural gas-fired fuel gas heaters. This will result in a NO_x emission limit of 0.058 lb/mmBtu. Based on this proposed emission rate, the heaters will contribute a total of 2.53 tons NO_x per year, based on its relatively low firing rate. By controlling the fuel gas heater's NO_x emissions using the forced draft LNB design, CPV Valley is implementing LAER control technology.

4.4.3.4 Emergency Diesel Engines

Although add-on controls, such as SCR, have been employed to reduce emissions from diesel engines with greater annual operating capacity factors, the limited annual operation rules out such controls. Combustion controls such as ignition retard are also not proposed for reasons cited in Section 4.4.2.4 above. Thus, CPV Valley proposes limited hours of operation and good combustion practices as LAER to achieve a NO_x emission rate of 0.859 lb/mmBtu for the emergency diesel fire pump and 1.5 lb/mmBtu for the emergency diesel generator. These limits correspond to only 0.5 tons of NO_x per year from the fire pump and 5.8 tons per year from the generator due to limited operation.

4.5 LAER Analysis for Volatile Organic Compounds

Since potential emissions from the Facility exceed the 50 ton/year New Source Review threshold for moderate nonattainment areas, VOC emissions must meet LAER requirements. The combined cycle combustion turbine and duct burner, auxiliary boiler, fuel gas heater and emergency diesel engines are all sources of VOC emissions at the proposed Project.

4.5.1 Review of VOC RBLC Database

4.5.1.1 Combined Cycle Combustion Turbines and Duct Burners

The search of the RBLC and available permits identified approximately 290 natural gas-fired combined cycle combustion turbine projects with VOC emission limits ranging from 0.4 to 34.2 ppm. The lowest permitted VOC emission limits for a combined cycle facility located in New York State are 1.0 ppm for the Empire Generating Project in Rensselaer, New York.

For oil firing, recent VOC emission limits have ranged from 1.6 to 252.8 ppm. There are four facilities permitted with 2 ppm VOC emission limits (as well as limits in other non-ppm units for which calculated conversions indicate ppm limits in this range) including the ConEd East River Repowering Project in Queens, New York. Since most recently permitted combined cycle facilities include oxidation catalysts, the relatively wide range appears to be a function of vendor guarantees for VOC reduction.

4.5.1.2 Auxiliary Boiler

The RBLC and recent air permit search for natural gas-fired boilers between 10 and 100 mmBtu/hr in size identified approximately 90 facilities with VOC emission limits between 0.002 to 0.079 lb/mmBtu. Most of the boilers that operate in a similar manner to the proposed boiler (i.e., auxiliary, backup, etc.) have an operational restriction on hours. Through the RBLC and recent air permit search, it cannot be confirmed if any boiler in this size range is presently operating on natural gas in New York State.

4.5.1.3 Fuel Gas Heaters

A review of the RBLC and permit search indicates that out of 16 projects with natural gas-fired fuel gas/fuel/efficiency/recuperator heaters, 13 of these projects have the lowest VOC emission limits, which fall between 0.005 and 0.007 lb/mmBtu. These limits are based on units employing either good combustion techniques or clean fuels.

4.5.1.4 Emergency Diesel Engines

The most stringent VOC emission permit limit shown in the RBLC database and permit search for a diesel fire pump of similar size and use as the proposed emergency diesel fire pump is 0.022 lb/mmBtu. The entire range of VOC emission limits for diesel fire pumps is 0.0133 – 0.9739 lb/mmBtu.

The most stringent VOC emission permit limit for an emergency diesel generator is 0.007 lb/mmBtu for a 11.4 mmBtu/hr emergency engine at the PSEG Waterford Energy Station in Ohio. It is unknown whether the facility is operating in compliance. The most recently permitted emergency generator similar in size to the one proposed for the Project is for the Ace Ethanol Plant in Wisconsin with a VOC limit of 0.033 lb/mmBtu, but it in unknown whether this facility is operating.

4.5.2 Identification of VOC Control Options and Technical Feasibility

4.5.2.1 Combined Cycle Combustion Turbines and Duct Burners

Combustion turbines have inherently low VOC emissions. The emissions of VOC in a combustion process are a result of the incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and H_2O.

The only post-combustion control method practical to reduce VOC emissions from combustion turbines is an oxidation catalyst. The optimum location for VOC control, in the 900 to 1,100 ^{o}F range, would be upstream of the HRSG or in the front-end section of the HRSG. However, at the high temperatures necessary to make the oxidation catalyst optimized for VOC reduction there is the undesirable result of causing substantially more conversion of SO_2 to SO_3 which may, in turn, react with water and/or ammonia to form sulfuric acid mist and/or ammonia salt PM-10 emissions. Therefore, the placement of the oxidation catalyst in the "cooler" section of the HRSG necessary for CO control is optimal, and has the additional side benefit of reducing VOC emissions from the combustion turbine.

4.5.2.2 Auxiliary Boiler

The rate of VOC emissions from boilers depends on combustion efficiency. Fuel hydrocarbons not converted to CO_2 can result in VOC emissions due to incomplete combustion. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Although the primary hydrocarbon constituents of natural gas – methane and ethane – are not considered to be VOC, trace amounts of VOC species in the natural gas fuel may also contribute to VOC emissions if they are not completely combusted in the boiler.

No technically feasible post-combustion control methods have been identified to assure the reduction of VOC emissions from auxiliary boilers. However, it is feasible to utilize an oxidation catalyst to control CO emissions from a boiler, which may also reduce VOC emissions. As described in the CO BACT analysis below, a few recently issued air permits specify oxidation catalysts for boilers.

4.5.2.3 Fuel Gas Heaters

Since a fuel gas heater combusts fuel in the same manner as an auxiliary boiler, externally, the technical feasibility analysis listed above is applicable. However, since no emission controls other than good combustion practices and clean fuels are listed in the RBLC and recent air permit search, these are the only controls considered technically feasible for this unit.

4.5.2.4 Emergency Diesel Engines

VOC from diesel engines are composed of a variety of organic compounds emitted into the atmosphere because of incomplete combustion. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. The quench layer is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperature to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. Add-on controls are not technically feasible.

4.5.3 Determination of LAER for VOC

4.5.3.1 Combined Cycle Combustion Turbines and Duct Burners

The Project is proposing to install an oxidation catalyst designed to reduce VOC emissions when firing natural gas to 0.7 ppm and 1.8 ppm without and with duct firing, respectively. The Project also proposes to reduce VOC emissions with an oxidation catalyst when firing ultra low-sulfur distillate oil to 0.7 ppm.

4.5.3.2 Auxiliary Boiler

The auxiliary boiler is proposed to employ good combustion practices and a restriction on annual operating hours. It is proposed that these control methods represent LAER for VOC emissions by limiting VOC emissions to 0.004 lb/mmBtu.

4.5.3.3 Fuel Gas Heaters

The burners selected for the proposed Project use modern design and combustion controls to optimize fuel combustion. It is proposed that the use of good combustion control represents VOC LAER for the fuel gas heater, resulting in a maximum VOC emission rate of 0.011 lb/mmBtu. Recent VOC limits for the fuel gas heaters listed in the limited sample provided by the RBLC indicate some variability in emissions estimates provided for this type of equipment, with limits higher and some lower than the proposed value. The proposed limit holds potential VOC emissions for this equipment to no more than 0.24 tons/year.

4.5.3.4 Emergency Diesel Engines

The application of good combustion practices and limited operating hours is proposed in order to achieve LAER for the emergency diesel fire pump and emergency diesel generator. The maximum VOC emissions from the emergency diesel fire pump and emergency generator are 0.3612 lb/mmBtu and 0.0331 lb/mmBtu, respectively. Potential VOC emissions from these pieces of equipment are than 0.5 tons/year total.

4.6 BACT Analysis for Carbon Monoxide

The combined cycle combustion turbine and duct burner, auxiliary boiler, fuel gas heater and emergency diesel fire pump are all sources of CO emissions at the proposed Project. Since potential emissions from the Project exceed the PSD “significance” threshold, CO emissions from all the units must incorporate BACT. CPV Valley will install an oxidation catalyst to control emissions of CO from the combustion turbines and duct burners.

4.6.1 Review of CO BACT Database

4.6.1.1 Combined Cycle Combustion Turbines and Duct Burners

A review of approximately 300 natural gas-fired combined cycle facilities listed in the USEPA’s RBLC as well as recently issued air permits (see Appendix E) lists CO emission limits ranging from 1.3 to 188.7 ppm. Both the Competitive Power Venture (CPV) Warren, LLC Project located in Front Royal, Virginia and the Astoria Energy, LLC Project located in Astoria, New York are permitted with CO emissions less than 2 ppm, yet neither of these projects are operational.

There are 24 permitted natural gas-fired combined cycle projects with CO emission limits of 2 ppm employing oxidation catalyst and/or good combustion practices. It is believed that at least five of these facilities are operating in compliance with their 2 ppm CO emission limits.

A review of the RBLC and recently issued permits for oil-fired combustion turbines indicated that the most stringent CO emission rate is 2.0 ppm at the McIntosh Combined-Cycle facility located in Rincon, Georgia which is achieved through the use of an oxidation catalyst. This facility is not believed to be operating yet. The next lowest permitted CO emission limit is 4 ppm, also achieved with an oxidation catalyst. This emission limit applies to four facilities, none of which are believed to be operational. The lowest permitted CO emission limit for a combined cycle combustion turbine operating on fuel oil that is believed to be operational is the KeySpan Ravenswood Facility which is limited to 5 ppm CO.

4.6.1.2 Auxiliary Boiler

A search of approximately 120 facilities found in the RBLC and recent air permit search for natural gas-fired boilers between 10 and 100 mmBtu/hr heat inputs yielded a range of CO emissions between 0.011 to 0.840 lb/mmBtu. The lowest CO emission limit for a natural gas-fired boiler that is believed to be operating is 0.033 lb/mmBtu for 2 auxiliary boilers located at the Panda-Rosemary Cogeneration Facility located in Roanoke Rapids, North Carolina. Although this boiler represents the lowest permitted CO emission limit achieved in practice, it should be noted that this boiler's gas-fired NO_x emissions are limited to 0.10 lb/mmBtu, which is on the high side of the recently permitted boilers listed in the RBLC and recent air permit search shown in Appendix E. There are 12 permitted natural gas-fired boilers with CO emission limits between 0.036 and 0.040 lb/mmBtu. CO emissions in this range correspond to a CO emission rate of 50 ppm. The lowest permitted CO emission limits are for boilers with only good combustion practices, operational restrictions and/or clean fuels listed as CO control technologies.

4.6.1.3 Fuel Gas Heaters

The RBLC and results of a recent air permit search for similar units indicates a range of permitted CO emission limits between 0.022 and 0.150 lb/mmBtu. This range of emission rates is achieved without add-on controls, but rather with good combustion practices and clean fuels.

4.6.1.4 Emergency Diesel Engines

The RBLC and results of a recent air permit search for diesel engines similar in size to the emergency diesel fire pump range from 0.059 lb/mmBtu to 12.98 lb/mmBtu. The lowest permitted CO emission limit for a diesel fire pump that is believed to be operating in compliance with its CO emission limit is 0.618 lb/mmBtu (converted from tons per year to lb/mmBtu) at the PSEG Waterford Energy, LLC Facility located in Columbus, Ohio.

The most stringent CO emission permit limit found in the RBLC database for an emergency diesel generator is 0.202 lb/mmBtu for a 2 MW emergency diesel generator at the Cardinal Glass Plant in Oklahoma. It is unknown whether the facility is operating in compliance. Existing permits show that add-on control technology is not practical for control of CO emissions from emergency equipment.

4.6.2 Identification of CO Control Options and Technical Feasibility

The following sections detail the options that were identified for controlling CO emissions from the combustion turbine, auxiliary boiler, fuel gas heater and emergency diesel fire pump. The technical feasibility of each option is also discussed.

4.6.2.1 Combined Cycle Combustion Turbines and Duct Burners

The formation of CO in the exhaust of a combustion turbine is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion, including insufficient O_2 availability, poor air/fuel mixing, cold wall flame quenching, reduced combustion temperature, decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

After combustion control, the only practical control method to reduce CO emissions from combustion turbines is an oxidation catalyst. Exhaust gases from the turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide (CO_2). CO reduction efficiencies in the range of 80 to 90 percent can be guaranteed, although CO reduction may at times be somewhat less than the design value at the low inlet concentrations that are expected for the Class-F turbines. No other technically feasible options are identified for combustion turbine CO control. Drawbacks of the oxidation catalyst include added cost, reduced turbine output and efficiency due to increased back pressure, and the potential for increased PM/PM-10 and/or sulfuric acid mist emissions.

4.6.2.2 Auxiliary Boiler

The common practice for CO control is ensuring efficient operation and proper design of the equipment. However, it is feasible to utilize an oxidation catalyst to control CO emissions from a boiler, and a few air permits specify oxidation catalysts to control CO from boilers in the 10 – 100 mmBtu/hr size range (Emery Generating Station in Iowa and Cabot Power Corporation in Massachusetts).

4.6.2.3 Fuel Gas Heaters

As described in Section 4.5.2.2 it is feasible to utilize an oxidation catalyst to control CO emissions from a boiler or heater, however, the small size of the fuel gas heaters (5.0 mmBtu/hr) suggests that add-on control technology is not feasible for the proposed fuel gas heaters. Good combustion control practice represents CO BACT for the Project's fuel gas heaters.

4.6.2.4 Emergency Diesel Engines

As reflected by existing permits, add-on control technology is not practicable for control of CO emissions from an emergency diesel engines operating less than 500 hours per year. Good combustion control practices and limited operating hours represent CO BACT for the Project's emergency diesel fire pump and emergency diesel engine.

4.6.3 Determination of BACT for CO

4.6.3.1 Combined Cycle Combustion Turbine and Duct Burner

The Project is proposing to install an oxidation catalyst designed to reduce CO emissions to 2.0 ppm during natural gas and ULSD firing without the duct burner operating. This is the lowest permitted emission rate for an operating combustion turbine, and the use of an oxidation catalyst satisfies BACT requirements. For oil firing, the Project proposes an oxidation catalyst to achieve BACT. The proposed permit limit is 2.0 ppm for the combustion turbine operating without the duct burner and 3.4 ppm for the combustion turbine operating on with duct burner firing. This constitutes the lowest permitted emission rate for a turbine, regardless of operational status.

4.6.3.2 Auxiliary Boiler

Based upon the analysis presented above, the Project is proposing to use good combustion practices to achieve CO emissions of 0.07 lb/mmBtu. Due to the feasibility of oxidation catalyst control technology on the proposed boiler, a cost control analysis is presented in Appendix F. This analysis shows that for this boiler’s limited operation, oxidation catalyst is cost-ineffective for the Project at approximately $31,000/ton CO controlled and thus is not considered BACT for this Project.

4.6.3.3 Fuel Gas Heater

The Project is proposing to use good combustion practices and clean fuels to achieve CO emissions of 0.084 lb/mmBtu. The RBLC and recent air permit search lists the Caithness Bellport Energy Center in Brookhaven, New York as the latest permit issued for a similar emission unit in USEPA Region 2. This project is not yet operating, but has been permitted with a CO emission rate of 0.084 lb/mmBtu (same as the proposed Project). Therefore, the proposed CO controls and emission rate represent BACT for the CPV Valley fuel gas heaters.

4.6.3.4 Emergency Diesel Engines

Existing permits show that add-on control technology is not practical for control of CO emissions from emergency equipment. Therefore, the Project is proposing BACT for CO emissions through good combustion practices and limiting operating hours. The proposed emission rate from the emergency diesel fire pump is 0.753 lb/mmBtu and the proposed CO emission rate from the emergency diesel generator is 0.136 lb/mmBtu.

4.7 BACT Analysis for PM/PM-10

The combined cycle combustion turbines and duct burners, auxiliary boiler, fuel gas heaters and emergency diesel engines are all sources of PM and PM-10 emissions. Since potential emissions from the Project exceed the PSD "significance" threshold for both PM and PM-10 emissions, PM and PM-10 emissions from the all the units must meet BACT emission rates.

4.7.1 Review of PM/ PM-10 BACT Databases

4.7.1.1 Combined Cycle Combustion Turbines and Duct Burners

A review of approximately 280 natural gas-fired and 70 fuel oil-fired combined cycle facilities from the USEPA's RBLC and recently issued air permit searches (see Appendix E) lists PM/PM-10 emission limits ranging from 0.0013 to 0.1400 lb/mmBtu for natural gas and PM/PM-10 emission limits ranging from 0.005 to 0.126 lb/mmBtu for fuel oil.

For gas firing, the lowest PM/PM-10 permit limit is found at a New York facility, the Calpine Wawayanda plant, which was permitted in July 2002 with a PM/PM-10 emission limit of 0.0013 lb/mmBtu at partial load and 0.0093 lb/mmBtu at full load. Another New York burning natural gas, the KeySpan Spagnoli Road Energy Center, was permitted with a PM/PM-10 emission limit of 0.0182 lb/mmBtu in April 2003 (almost a year after the Wawayanda permit was issued).

For oil firing, the lowest PM/PM-10 permit limit at a New York facility, the ConEd East River Repowering Project, was permitted in August 2001 with a PM/PM-10 emission limit of 0.033 lb/mmBtu. Another New York facility burning fuel oil, the Mirant Bowline, LLC Facility, was permitted with a PM/PM-10 emission limit of 0.058 lb/mmBtu in March 2002 (more than 6 months after the ConEd East River Project permit was issued).

In fact, the permits for natural gas- and fuel oil-fired combined cycle combustion turbine projects issued in New York do not follow any sort of emissions versus permit date trend (i.e., later permit date = lower PM/PM-10 emission rate). Note also that two of the four projects (Calpine Wawayanda and KeySpan Spagnoli Road) identified above have not been built. Thus, the control technologies, good combustion practice and low-sulfur, should be considered the driving factor for proposing BACT.

4.7.1.2 Auxiliary Boiler

A review of the RBLC shows that typically good combustion practices and low-sulfur fuel have been used as BACT for gas-fired boilers. PM and PM-10 emission limits for gas-fired boilers of similar size that are believed to be operating in compliance with their permit limits are as low as 0.003 lb/mmBtu.

4.7.1.3 Fuel Gas Heaters

The RBLC and results of a recent air permit search for similar units at 21 facilities indicates a range of permitted PM/PM-10 emission limits between 0.001 and 0.400 lb/mmBtu with 18 out of 21 projects permitted with PM/PM-10 emission limits between 0.005 and 0.011 lb/mmBtu. This entire range of emission rates is achieved without add-on controls, but rather with good combustion practices and clean fuels.

4.7.1.4 Emergency Diesel Engines

A review of the RBLC shows that only good combustion and low-sulfur fuel have been used as BACT for diesel engines.

4.7.2 Identification of PM/PM-10 Control Options and Technical Feasibility

4.7.2.1 Combustion Turbines and Duct Burners

PM and PM-10 emissions from the combustion turbines may be formed from non-combustible constituents in fuel or combustion air, from products of incomplete combustion, or from the formation of ammonium sulfates due to the conversion of SO_2 to SO_3, which is then available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion. It is conservatively expected that all PM from the Project will be equal to PM-10. PM and PM-10 emissions from combustion turbines are inherently low.

The combustion of clean burning fuels is the most effective means for controlling PM emissions from combustion equipment. CPV Valley is not aware of any combustion turbine project that has been required to add on PM or PM-10 controls. Post-combustion controls, such as baghouses, scrubbers and electrostatic precipitators (ESP) are impractical due to the high pressure drops associated with these units and the low concentrations of PM/PM-10 present in the exhaust gas.

4.7.2.2 Auxiliary Boiler

PM/PM-10 emissions from natural gas-fired boilers may be due to products of incomplete combustion as well as non-combustible constituents in the flue gas stream. Proper burner design and operation as well as the primary use of natural gas will control PM/PM-10 emissions to low levels. PM/PM-10 control technologies, such as ESP or fabric filters are common practice on solid fuel boilers, and ESPs are also applied on boilers firing residual oil, where the filterable component of PM is greater than that for the proposed Project.

4.7.2.3 Fuel Gas Heaters

PM/PM-10 emissions from gas-fired fuel gas heaters also may be due to products of incomplete combustion. Proper burner design and operation as well as the use of pipeline quality natural gas will control PM/PM-10 emissions. PM/PM-10 control technologies, such as ESP or fabric filters are common practice on solid fuel boilers, and ESPs are also applied on boilers firing residual oil, where the filterable component of PM is greater than that for the proposed Project. These controls are not practical for this type of unit.

4.7.2.4 Emergency Diesel Engines

Particulate matter emissions from oil-fired internal combustion engines may result from trace metals present in the fuel, unburned carbon-containing materials and sulfate formation. Good combustion practices and use of clean fuels are the methods currently utilized to minimize PM and PM-10 emissions from diesel engines. Post-combustion controls, such as baghouses, scrubbers and ESPs are impractical due to the high-pressure drops associated with these technologies and the low concentrations of PM, and PM-10 present in the exhaust gas. In addition, any add-on controls applied would have extremely high cost, on a dollar per ton PM/PM-10 removed basis, since this emergency equipment is expected to operate infrequently. No other PM or PM-10 control devices are identified for diesel engines in USEPA's AP-42, Compilation of Air Pollutant Emission Factors, Section 3.

4.7.3 Determination of BACT for PM/PM-10

4.7.3.1 Combined Cycle Combustion Turbines and Duct Burners

Good combustion techniques and low-sulfur fuels have been proposed to limit PM/PM-10 emissions. Proposed emission limits for PM/PM-10 when firing natural gas in the combustion turbine are 0.0073 lb/mmBtu for the combustion turbine only and 0.0062 lb/mmBtu for the combustion turbine and duct burner. The proposed emission limit for PM/PM-10 when firing fuel oil in the combustion turbine is 0.068 lb/mmBtu for the combustion turbine only and 0.0368 lb/mmBtu These values are within the range of recent BACT determinations for combustion turbines.

4.7.3.2 Auxiliary Boiler

The Project proposes the exclusive use of clean-burning fuels in conjunction with good combustion practices as BACT. The proposed PM/PM-10 limit for the auxiliary boiler is 0.0063 lb/mmBtu.

4.7.3.3 Fuel Gas Heaters

The Project proposes the exclusive use of clean-burning pipeline quality natural gas in conjunction with good combustion practices as BACT. The proposed BACT PM/PM-10 limit for the fuel gas heaters is 0.0076 lb/mmBtu.

4.7.3.4 Emergency Diesel Engines

The Project proposes to use ULSD, employ good combustion practices, and limit operating hours as BACT for PM/PM-10. The PM/PM-10 emission rates from the emergency diesel fire pump and the emergency diesel generator are proposed as 0.04 lb/mmBtu and 0.009 lb/mmBtu, respectively.

4.8 BACT Analysis for Sulfur Dioxide and Sulfuric Acid Mist

SO_2 emissions are formed from oxidation of sulfur in the fuel. H_2SO_4 emissions, in addition to being a function of fuel sulfur content, are also related to the amount of oxidation of fuel sulfur to SO_3. Sulfuric acid is produced when SO_2 is converted to SO_3 in the presence of a catalyst and is then further combined with water to form H_2SO_4 (sulfuric acid). Note that to be available to react with water to form sulfuric acid, the SO_3 would have to avoid first reacting with ammonia slip (and forming ammonia salts). During the combustion process, most of the sulfur is converted to SO_2. For the combustion turbine, twenty percent of the SO_2 is assumed to be converted to SO_3 as a result of the combined effects of the combustion process and oxidation of the SCR and oxidation catalysts, and eventually to H_2SO_4 and/or ammonium sulfate salts.

4.8.1 Review of SO_2 and H_2SO_4 BACT Database

A review of the RBLC and search of recently issued air permits indicated only one option for SO_2 and H_2SO_4 control. For all units where SO_2 and H_2SO_4 control was identified, the only option considered was the combustion of low-sulfur fuels. No other controls have been implemented on a combustion turbine, boiler/heater or diesel engine.

4.8.1.1 Combined Cycle Combustion Turbines and Duct Burners

A search of approximately 225 permits for natural gas-fired combined cycle combustion turbines yielded a range of SO_2 emission limits between 0.0002 and 1.0212 lb/mmBtu. A search of approximately 83 permits for fuel oil-fired combined cycle combustion turbines yielded a range of SO_2 emission limits between 0.0009 and 0.4028 lb/mmBtu.

A search of approximately 95 permits for natural gas-fired combined cycle combustion turbines yielded a range of BACT H_2SO_4 emission limits between 0.0001 and 0.00188 lb/mmBtu. A search of approximately 22 permits for fuel oil-fired combined cycle combustion turbines yielded a range of H_2SO_4 emission limits between 0.0001 and 0.0230 lb/mmBtu.

4.8.1.2 Auxiliary Boiler

The most stringent emission limit identified in the RBLC and recent permit search from approximately 90 natural gas-fired boiler projects similar to the auxiliary boiler proposed at the Project is 0.0004 lb/mmBtu.

A search of the RBLC for H_2SO_4 emissions from natural gas fired boilers similar in size to the auxiliary boiler proposed at the Project yielded one result. The Calpine Wawayanda facility in New York has a BACT limit of 0.0002 lb/mmBtu for H_2SO_4 emissions from an 80 mmBtu/hr auxiliary boiler.

4.8.1.3 Fuel Gas Heaters

A search of the RBLC indicated that lowest SO_2 emission limits for heaters of comparable size range from 0.001 to 4.0 lb/mmBtu with 13 out of the 14 total projects identified having SO_2 emission limits between 0.001 and 0.005 lb/mmBtu.

There is very limited data in the RBLC for sulfuric acid emissions from small heaters/boilers. CPV Valley therefore examined sulfur dioxide controls for similar sources since the controlling SO2 emissions from combustion units would also control H_2SO_4. A search of the RBLC indicated that the use of low sulfur fuels represents BACT for both SO_2 and H_2SO_4 emissions.

4.8.1.4 Emergency Diesel Engines

A search of the RBLC indicated that lowest SO_2 emission limits for diesel fire pumps range from 0.003 to 1.597 lb/mmBtu. The lowest SO_2 emission limit for an emergency generator identified in the RBLC is 0.0002 lb/mmBtu using ULSD.

A search of the RBLC indicated that lowest H_2SO_4 emission limits for diesel fire pumps range from 0.0017 to 0.0392 lb/mmBtu. There is only one facility in the RBLC, Cornell Combined Heat and Power Project in Tompkins, New York which has a H_2SO_4 limit of 0.0002 lb/mmBtu for a 1000 kW emergency generator.

4.8.2 Identification of SO_2 and H_2SO_4 Control Options and Technical Feasibility

4.8.2.1 Combined Cycle Combustion Turbines and Duct Burners

Strategies for the control of SO_2 emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low-sulfur fuels including the ultra low sulfur fuel oil with less than 15 ppm sulfur by weight that heavy duty trucks and buses will be required to burn by 2006. Post-combustion controls comprise various wet and dry flue gas desulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to high-pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low SO_2 concentrations in this situation. The use of natural gas and ultra low-sulfur distillate oil results in low emission levels of SO_2 and H_2SO_4.

4.8.2.2 Auxiliary Boiler

FGD is a technology used to control SO_2 emissions from various combustion sources. Installation of such systems is an established technology principally on coal-fired and high-sulfur oil-fired steam electric generating stations, but is not feasible for boilers fired with natural gas, such as the one proposed for this Project.

4.8.2.3 Fuel Gas Heaters

Installation of post-combustion SO_2 control systems is an established technology principally on coal-fired and high-sulfur oil-fired steam electric generating stations, but is not feasible for a small fuel gas heater fired with natural gas only.

4.8.2.4 Emergency Diesel Engines

The only practical control technique available for emergency diesel engines that will operate no more than 500 hours per year is the use of low-sulfur fuel.

4.8.3 Determination of BACT for H_2SO_4

4.8.3.1 Combined Cycle Combustion Turbines and Duct Burners

When firing natural gas, CPV Valley proposes to use low-sulfur fuel (0.8 grains/100 scf) to meet BACT for SO_2 and H_2SO_4. SO_2 emission will be limited to 0.0022 lb/mmBtu and H_2SO_4 emissions will be limited to 0.0007 lb/mmBtu.

For oil firing, the Project proposes ultra low sulfur oil (15 ppm) as BACT for SO_2 and H_2SO_4. SO_2 emissions will be limited to 0.0015 lb/mmBtu. Sulfuric acid emissions will be limited to 0.0005 lb/mmBtu.

4.8.3.2 Auxiliary Boiler

The Project proposes to fire natural gas in the auxiliary boiler to meet BACT for sulfur dioxide and sulfuric acid. The proposed SO_2 emission limit is 0.0022 lb/mmBtu; the H_2SO_4 BACT emission limit is 0.0002 lb/mmBtu.

4.8.3.3 Fuel Gas Heaters

The Project proposes to fire pipeline quality natural gas in the fuel gas heaters to meet BACT for SO_2 and H_2SO_4. The proposed SO_2 BACT emission limit is 0.0022 lb/mmBtu. The proposed H_2SO_4 BACT emission limit is 0.0002 lb/mmBtu.

4.8.3.4 Emergency Diesel Engines

The use of ULSD is proposed as BACT for the control of sulfur dioxide and sulfuric acid. The proposed sulfur dioxide BACT limit for the emergency diesel engines is 0.0014 lb/mmBtu. The sulfuric acid BACT emission limits for the emergency diesel fire pump and the emergency diesel generator is 0.00003 lb/mmBtu.

4.9 Summary of Control Technology Proposals

Tables 4–1 through 4-4 provide a summary of the control technology proposals presented for regulated pollutants.

Table 4-1: Summary of Proposed BACT/LAER – Combustion Turbine/Duct Burner				
Pollutant	**Section**	**Limit**	**Method**	**Basis**
NO_x	4.4	2.0 ppm (CT – gas firing with & without DB) 6.0 ppm (CT– oil firing)	DLN & SCR Water Injection & SCR	LAER
VOC	4.5	0.7 ppm (CT – gas firing) 0.7 ppm (CT– oil firing) 1.8 ppm (CT– gas firing with DB)	Good combustion controls & oxidation catalyst	LAER
CO	4.6	2.0 ppm (CT – gas firing) 2.0 ppm (CT– oil firing) 3.4 ppm (CT– gas firing with DB)	Good combustion controls & oxidation catalyst	BACT
PM/PM-10	4.7	0.0073 lb/mmBtu (gas firing with & without DB) 0.0368 lb/mmBtu (oil firing)	Low-sulfur fuels	BACT
SO_2	4.8	0.0022 lb/mmBtu (gas firing with & without DB) 0.0015 lb/mmBtu (oil firing)	Low-sulfur fuels	BACT
H_2SO_4	4.8	0.0007 lb/mmBtu (gas firing with & without DB) 0.0005 lb/mmBtu (oil firing)	Low-sulfur fuels	BACT

Table 4-2: Summary of Proposed BACT/LAER – Auxiliary Boiler				
Pollutant	**Section**	**Limit**	**Method**	**Basis**
NO_x	4.4	0.0450 lb/mmBtu	LNB & FGR	LAER
VOC	4.5	0.0038 lb/mmBtu	Good combustion controls	LAER
CO	4.6	0.0721 lb/mmBtu	Good combustion controls	BACT
PM/PM-10	4.7	0.0063 lb/mmBtu	Low-sulfur fuel	BACT
SO_2	4.8	0.0022 lb/mmBtu	Low-sulfur fuel	BACT
H_2SO_4	4.8	0.0002 lb/mmBtu	Low-sulfur fuel	BACT

Table 4-3: Summary of Proposed BACT/LAER – Fuel Gas Heater				
Pollutant	**Section**	**Limit**	**Method**	**Basis**
NO_x	4.4	0.058 lb/mmBtu	Forced draft LNB	LAER
VOC	4.5	0.011 lb/mmBtu	Good combustion controls	LAER
CO	4.6	0.084 lb/mmBtu	Good combustion controls	BACT
PM/PM-10	4.7	0.0076 lb/mmBtu	Low-sulfur fuel	BACT
SO_2	4.8	0.0022 lb/mmBtu	Low-sulfur fuel	BACT
H_2SO_4	4.8	0.0002 lb/mmBtu	Low-sulfur fuel	BACT

Table 4-4: Summary of Proposed BACT/LAER – Emergency Diesel Fire Pump				
Pollutant	**Section**	**Limit**	**Method**	**Basis**
NO_x	4.4	0.857 lb/mmBtu	Good combustion controls	LAER
VOC	4.5	0.3612 lb/mmBtu	Good combustion controls	LAER
CO	4.6	0.75 lb/mmBtu	Good combustion controls	BACT
PM/PM-10	4.7	0.043 lb/mmBtu	Low-sulfur fuel	BACT
SO_2	4.8	0.0014 lb/mmBtu	Low-sulfur fuel	BACT
H_2SO_4	4.8	0.00003 lb/mmBtu	Low-sulfur fuel	BACT

Table 4-5: Summary of Proposed BACT/LAER – Emergency Diesel Generator				
Pollutant	**Section**	**Limit**	**Method**	**Basis**
NO_x	4.4	4.97 g/hp-hr	Good combustion controls	LAER
VOC	4.5	0.0331 lb/mmBtu	Good combustion controls	LAER
CO	4.6	0.45 g/hp-hr	Good combustion controls	BACT
PM/PM-10	4.7	0.03 g/hp-hr	Low-sulfur fuel	BACT
SO_2	4.8	0.0014 lb/mmBtu	Low-sulfur fuel	BACT
H_2SO_4	4.8	0.00003 lb/mmBtu	Low-sulfur fuel	BACT

5.0 AIR QUALITY MODELING ANALYSIS

Details concerning the modeling methodology used to support this air permit application are provided in the revised Air Quality Modeling Protocol that is included in Appendix G. A modeling protocol for the Project was originally submitted to NYSDEC and USEPA in September 2008 and was subsequently revised in November 2008 to account for Project design changes and agency review comments. The methodology used for the modeling is intended to be consistent with guidance provided by USEPA in the "Guideline on Air Quality Models" which appears in the Code of Federal Regulations (CFR) at Appendix W of 40 CFR Part 51 and by NYSDEC in "NYSDEC Guidelines on Dispersion Modeling Procedures for Air Quality Impact Analysis" (DAR-10) and to address issues raised subsequently in agency review comments on the original protocol.

The following subsections provide an overview of the modeling methodology with references to more detailed discussions and associated tables that appear in the revised Air Quality Modeling Protocol. In addition, the following subsections provide information concerning the modeling results and conclusions. Sections 5.1 through 5-5 describe modeling and procedures conducted using the AERMOD model to determine Project impacts relative to SILs, SMCs, NAAQS, PSD increments, and NYSDEC guideline concentrations for non-criteria pollutants. Section 5.6 covers additional impact analyses required under PSD.

5.1 Source Data

The modeling analyses include the following Project sources: two combustion turbines with duct burners (also referred to herein as combined cycle units), the auxiliary boiler, the emergency diesel generator, the emergency diesel fire pump, and the fuel gas heaters. These sources are discussed in Section 2.0 of the application, and detailed emission calculations and exhaust parameters are provided in Appendix B. In addition, emission rates and stack exit parameters used in the modeling analyses for Project sources are provided in the following tables in the revised Air Quality Modeling Protocol: combined cycle units (Tables 2-3 and 2-4), emergency diesel generator (Table 2-5), auxiliary boiler (Table 2-6), emergency diesel fire pump (Table 2-7), and fuel gas heaters (Table 2-8). Proposed stack locations in UTM coordinates are provided in Table 2-9 of the revised Air Quality Modeling Protocol.

A Good Engineering Practice (GEP) stack height analysis was conducted and is documented in Section 2.8 of the revised Air Quality Modeling Protocol. A GEP formula stack height of 287.5 feet was calculated based on the dimensions of the air cooled condensers. All proposed Project stacks are below GEP formula height, so the modeling accounts for the potential effects of building downwash on emissions from Project sources. The most recent version of USEPA's

Building Profile Input Program for PRIME (BPIPPRM), dated 04274, was used to determine GEP stack height and the effective building dimensions as a function of flow vector for each Project source in the modeling. Appendix A of the revised Air Quality Modeling Protocol contains representative BPIPPRM input and output files.

5.2 Model Selection and Options

The AERMOD model (version 07026) was used to determine predicted impacts from the proposed Project. AERMOD is identified by USEPA in the "Guideline on Air Quality Models" (40 CFR 51, Appendix W) as a recommended refined model for a wide range of regulatory applications in all types of terrain and in cases where aerodynamic downwash is important. AERMOD includes the PRIME downwash algorithm which accounts for potential building wake and cavity effects on stack emissions. AERMOD also includes a refined complex terrain algorithm and can provide predicted impacts in all terrain regimes.

The proposed stack heights are below the maximum GEP formula height calculated based on proposed buildings and structures, so building downwash may affect stack emissions. In addition, some stack heights are short enough relative to nearby structures that building cavity effects on stack emissions may be important. As mentioned above, AERMOD can account for building wake and cavity effects on stack emissions. The receptor grid, described later, includes some receptors in simple terrain and others that are in complex terrain (i.e., terrain that exceeds the height of the stacks). In complex terrain, AERMOD employs the dividing streamline concept to treat the effects of plume and terrain interactions. As mentioned previously, AERMOD is recommended for use in all terrain regimes. For these reasons, AERMOD is an appropriate and recommended model to use for estimating impacts from Project emissions. Therefore, AERMOD with regulatory default model options was used for these modeling analyses.

5.3 Receptor Grid

The basic receptor grid for the AERMOD analyses was defined by the intersections of concentric circles and radial lines paced at ten degree intervals from the center of the circles. The circles were centered on a point in the power generation area of the Project. The grid was "polar" in nature, but the receptor coordinates were provided to AERMOD as discrete Cartesian receptors in UTM coordinates referenced to zone 18 (NAD 83). The basic grid origin was centered on a point with the following coordinates: (545,909.0 meters E, 4,584,682.75 meters N). Receptors were located every 10 degrees at the following distances from the grid origin:

- At 100m intervals from 200m to 5,000m;
- At 200m intervals from 5,000m to 10,000m;
- At 500m intervals from 10,000m to 15,000m; and
- At 1,000m intervals from 15,000m to 30,000m.

Fence line receptors were included at intervals of 10 meters or less surrounding the facility. Grid receptors within fenced plant property were excluded from the grid, since they were not in areas considered to be ambient air.

The final receptor grid consisted of 3,552 grid receptors and 180 fence line receptors for a total of 3,732 model receptors. Figures 3-1, 3-2, and 3-3 in the revised Air Quality Modeling Protocol display the model receptors. Figure 3-1 shows the fence line along with the locations of proposed Project stacks and major buildings and structures. Figure 3-2 shows the grid receptors out to 5,000 meters, while Figure 3-3 shows the entire receptor grid out to 30,000 meters. The receptor grid points are plotted over a background that depicts the underlying terrain field.

The AERMAP (Version 06341) preprocessor program was used to extract receptor elevations and hill heights based on 10m Digital Elevation Model (DEM) data. The analysis used 7.5-minute DEM data obtained from the US Geological Survey (USGS). Appendix B of the revised Air Quality Modeling Protocol contains extracts from the AERMAP input files showing the control pathway lines.

5.4 Meteorological Data

As discussed in Section 3.3 of the revised Air Quality Modeling Protocol, a five-year meteorological database including hourly surface level meteorological data for the years 2002 through 2006 from Orange County Airport in Montgomery, New York was used in the modeling analyses with AERMOD. Concurrent upper air data from Albany International Airport were incorporated in the meteorological database used in the modeling analyses with AERMOD. The data from Orange County Airport were obtained from the U.S. National Climatic Data Center (NCDC) and processed with USEPA's AERMET meteorological preprocessor (Version 06341).

As discussed in the revised Air Quality Modeling Protocol in Section 3.3, the selected data were determined to be representative of conditions that would be expected at the Project site and satisfy the data capture rate of 90 percent required for projects subject to PSD.

USEPA's AERSURFACE tool (most recent version dated 08009) was used to determine values of surface characteristics (surface roughness length, Bowen ratio, and albedo) that are required inputs for AERMET. Land cover data from the USGS National Land Cover Data 1992 archives (NLCD92) data for areas surrounding the surface level meteorological measurement site were used in accordance with current modeling guidance from USEPA and NYSDEC. Additional information concerning the determination of these parameters is provided in Section 3.4 of the revised Air Quality Modeling Protocol, and copies of the AERSURFACE input and output files are provided in Appendix C of the same document.

5.5 AERMOD Results

The following subsections describe the results of modeling the Project and, in some cases, other sources and interprets the results in a regulatory context.

5.5.1 Modeling to Determine Worst-Case Operating Conditions

As described in Section 4.1 of the revised Air Quality Modeling Protocol, modeling of the combined cycle units was conducted for a matrix of representative normal operating conditions covering a range of turbine loads, ambient temperatures, and fuels and accounted for supplementary duct firing (for natural gas operation) and evaporative cooling. Subsequent modeling to determine total Project impacts included operating cases with the highest emission rates for the combined cycle units as well as the operating conditions, including startup conditions where applicable, that yielded the maximum associated predicted impacts from the combined cycle units. Section 4.5 of the revised Air Quality Modeling Protocol describes how startup emissions were incorporated in subsequent modeling to determine maximum short-term impacts from the Project. Table 4-2 of the revised Air Quality Modeling Protocol summarizes the combined cycle operating cases that were used in subsequent modeling to determine maximum Project impacts.

5.5.2 Comparison of Project Impacts with SILs

Modeling to determine maximum Project impacts for comparison to SILs defined by USEPA at 40 CFR 51.165(b)(2) was conducted in accordance with procedures in the revised Air Quality Modeling Protocol. The modeling included combined cycle unit operating cases with the maximum emission rates as well as operating conditions that had the highest associated predicted impacts, including startup conditions where applicable, from the combined cycle units.

The maximum predicted Project impacts are provided in Tables 5-1, 5-2, and 5-3. Table 5-1 provides results for cases with gas firing only in the combined cycle units, while Table 5-2 provides results for cases for which only oil is fired in the combustion turbines. The results in Table 5-2 account for proposed limits on annual firing of ULSD. Table 5-3 provides overall worst-case impacts, including the effect of startup emissions on short-term impacts along with maximum annual impacts reflecting the potential use of both natural gas and ULSD during the year.

Table 5-1: Maximum Project Impacts - Gas Firing in Combustion Turbines							
Pollutant	**Averaging Period**	**Impact (ug/m^3)**	**X (km)**	**Y (km)**	**time**	**Turbine case**	**SIL (ug/m^3)**
NO_2	annual	0.63	546.983	4584.538	2002	SG10	1
CO	1	45.92	546.739	4585.116	2006029300	SG04	2,000
	8	21.41	546.816	4584.719	2006131800	SG09	500
SO_2	3	3.28	545.318	4586.674	2005038300	SG10	25
	24	0.60	545.318	4586.674	2003083	SG06	5
	annual	0.04	547.389	4585.375	2002	SG10	1
PM-10	24	1.71	545.318	4586.674	2003083	SG06	5
	annual	0.18	546.982	4584.747	2002	SG15	1

Notes:
SIL = significant impact level

Table 5-2: Maximum Project Impacts - ULSD Firing in Combustion Turbines							
Pollutant	**Averaging Period**	**Impact (ug/m^3)**	**X (km)**	**Y (km)**	**time**	**Turbine case**	**SIL (ug/m^3)**
NO_2	annual	0.52	546.983	4584.538	2002	SF09	1
CO	1	45.92	546.739	4585.116	2006029300	SF03	2,000
	8	21.41	546.816	4584.719	2006131800	SF06	500
SO_2	3	1.83	545.318	4586.674	2005038300	SF09	25
	24	0.31	545.318	4586.674	2003083	SF02	5
	annual	0.003	546.988	4584.752	2002	SF09	1
PM-10	24	6.93	545.318	4586.674	2005037	SF06	5
	annual	0.04	547.389	4585.375	2002	SF10	1

Notes:
SIL = significant impact level

Table 5-3:Maximum Project Impacts							
Pollutant	**Averaging Period**	**Impact (ug/m³)**	**X (km)**	**Y (km)**	**time**	**Turbine case**	**SIL (ug/m³)**
NO_2	annual	0.85	546.982	4584.747	2003	g10f09	1
CO	1	562.80	545.511	4586.445	2004010123	ColdFO06	2,000
	8	181.88	545.446	4586.521	2005020708	ColdFO06	500
SO_2	3	3.28	545.318	4586.674	2005038300	SG10	25
	24	0.60	545.318	4586.674	2003083	SG06	5
	annual	0.04	547.389	4585.375	2002	SG10	1
PM-10	24	9.89	545.446	4586.521	2005020724	ColdFO06	5
	annual	0.18	546.982	4584.747	2002	SG15	1

Notes:
SIL = significant impact level
Startup emissions included for short-term impacts

The results in Tables 5-1, 5-2, and 5-3 show that maximum predicted Project impacts are below SILs for NO_2, CO, and SO_2. The results also show that maximum predicted Project impacts of PM-10 are below SILs for cases where natural gas is fired in the combustion turbines. A demonstration that maximum Project impacts are less than SILs for a given pollutant establishes that the Project will not be capable of causing or contributing to any violation of a corresponding NAAQS or PSD increment.

Under longstanding USEPA guidance and interpretations, the SILs are used to determine if a source makes or could make a significant contribution to a predicted violation of a NAAQS or Class II PSD increment. If a major source or major modification is predicted to have maximum impacts that are below the SILs, then a cumulative (or "full") impact analysis that includes other facilities is not required, and the impacts of the project are considered to be *de minimis* or insignificant. By showing that maximum predicted Project impacts will be below the corresponding SILs for a given pollutant, the Project is exempt from the requirement to conduct any additional analyses to demonstrate compliance with NAAQS and/or Class II PSD increments for that pollutant.

The maximum predicted 24-hour impacts of PM-10 for cases with ULSD firing in the combustion turbines exceed the 24-hour SIL. Therefore, additional cumulative impact modeling to demonstrate compliance with NAAQS and PSD increments was required. This additional modeling is described in Section 5.5.4.

The maximum extent of the predicted significant PM-10 impacts was approximately 4.6 km and was associated with an operating condition that included turbine startup emissions. As described in Section 5.5.4, model receptors included in the cumulative modeling for PM-10 extended out ot 4.6 km in order to cover the maximum radial extent of the Project's significant impacts.

5.5.3 Comparison of Project Impacts with SMCs

Modeling to determine maximum Project impacts for comparison to significant monitoring concentrations (SMCs) defined by USEPA was conducted in accordance with procedures in the revised Air Quality Modeling Protocol. If a new major source or major modification can demonstrate that impacts from a project are less than the SMCs defined at 40 CFR 52.21(i)(5)(i), then a source can be exempted from preconstruction monitoring requirements that might otherwise apply under the PSD program.

Table 5-4 provides a summary of maximum predicted Project impacts relative to the SMCs and supports the requested waiver request from preconstruction monitoring that was submitted to USEPA. A copy of the waiver request is included in Appendix C. The maximum predicted Project impacts are below all associated SMCs.

Table 5-4: Maximum Project Impacts -- Comparison to SMCs

Pollutant	Averaging Period	Concentration (ug/m^3)	SMC (ug/m^3)
CO	8-hour	182	575
NO_2	Annual	0.8	14
SO_2	24-hour	0.6	13
PM-10	24-hour	9.9	10
Pb	3-month	0.009	0.1

Notes:
a. SMC = significant monitoring concentration
b Short-term impacts of CO and PM-10 account for higher impacts that may occur during combustion turbine startup.
c. Predicted impacts for Pb represent maximum 24-hour impacts during oil firing in combustion turbines. Impacts for 3-month averaging period would be much smaller.

5.5.4 Cumulative Impact Modeling for PM-10

Cumulative impact modeling analyses were conducted for PM-10 consistent with procedures described in the revised Air Quality Modeling Protocol. The cumulative impact analyses included the Project along with other facilities and incorporated consideration of background air quality. The modeling was conducted to demonstrate that impacts from the Project and other large PM-10 sources would comply with NAAQS and PSD increments for PM-10.

The multi-source PM-10 emission inventory included large PM-10 sources within a region extending 50 km beyond the 4.6 km Project significant impact area (or out to approximately 55 km from the Project). Appendix H contains additional details concerning the development of the cumulative PM-10 emissions inventory as well as summary tables of emissions and stack parameters that were used in the modeling. The Project was included in the cumulative modeling analyses using the operating scenario that had previously been determined to yield the maximum 24-hour PM-10 Project impact and included consideration of turbine startup emissions. Receptors within the maximum radial extent of the Project SIA (i.e., within 4.6 km) were included in the cumulative PM-10 modeling. The modeling used the full 5-year meteorological data base.

Table 5-5 provides a summary of the high second-high 24-hour and maximum annual cumulative predicted impacts of PM-10 for each year. Table 5-6 provides a comparison to NAAQS and PSD increments. For comparison with PSD increments for PM-10, it is conservatively assumed that all emissions in the multi-source PM-10 inventory are increment consuming. Background air quality levels for PM-10 are included in Table 4-4 of the revised Air Quality Modeling Protocol and are based on concentrations monitored in 2005 through 2007 at a monitor in Fort Lee, in Bergen County, New Jersey. This monitor is located at the George Washington Bridge Overpass in an urban setting dominated by mobile sources. The data from this monitor should provide conservative estimates of PM-10 background air quality for the Project site. The background concentrations listed in Table 5-6 represent the maximum annual PM-10 concentration and the second highest 24-hour PM-10 concentration measured during 2005 through 2007 at this monitor.

The results show that the total predicted impacts do not exceed PSD increments for PM-10 and that the sum of total predicted impacts and background PM-10 levels do not exceed NAAQS for PM-10. Therefore, compliance with PSD increments and NAAQS for PM-10 is demonstrated.

Table 5-5: Cumulative PM-10 Modeling Results						
Year	**Averaging Period**	**Rank**	**Impact (ug/m^3)**	**X (meters)**	**Y (meters)**	**Day**
2002	24-Hour	H2H	6.26	548139	4586675	20-Jun
2003	24-Hour	H2H	5.89	548139	4586675	16-Mar
2004	24-Hour	H2H	7.15	551233	4587133	13-Sep
2005	24-Hour	H2H	7.22	547953	4585832	25-Oct
2006	24-Hour	H2H	7.82	551687	4586393	27-Aug
2002	Annual	MAX	1.00	548239	4586848	
2003	Annual	MAX	0.98	548189	4586761	
2004	Annual	MAX	1.02	548189	4586761	
2005	Annual	MAX	0.96	548189	4586761	
2006	Annual	MAX	1.05	548189	4586761	
Notes: H2H = high second-high						

Table 5-6: Compliance with PM-10 PSD Increments and NAAQS						
Averaging Period	**Rank**	**Impact (ug/m^3)**	**PSD Increment (ug/m^3)**	**Background (ug/m^3)**	**Total Concentration (ug/m^3)**	**NAAQS (ug/m^3)**
24-hour	H2H	7.8	30	78	85.8	150
Annual	MAX	1.1	17	35	36.1	50
Notes: H2H = high second-high						

5.5.5 PM-2.5 Impacts

The USEPA promulgated NAAQS for PM-2.5 in 1997 and subsequently revised the 24-hour PM-2.5 standard in 2006. Even though the PM-2.5 monitor in Newburg, Orange County, New York has historically shown PM-2.5 levels that are below the associated NAAQS for PM-2.5, Orange County was included in the 10-county New York City Metropolitan Nonattainment Area for PM-2.5 primarily based on EPA guidance recommending the presumptive use of Metropolitan Statistical Area (MSA) boundaries for defining the boundaries for PM-2.5 nonattainment areas. The nonattainment status of the New York City Metropolitan Nonattainment Area for PM-2.5 is based on the PS 59 monitor in Manhattan.

NYSDEC Commissioner's Policy 33 (CP-33), "Assessing and Mitigating Impacts of Fine Particulate Matter Emissions," was issued on December 29, 2003 for use with projects for which NYSDEC is the lead agency conducting a review for purposes of the State Environmental Quality Review Act (SEQRA). CP-33 requires an assessment of ambient impacts from projects with potential PM-10 emissions exceeding a *de minimis* threshold of 15 tpy. For projects with emissions exceeding this emissions threshold, CP-33 uses 24-hour and annual project impact levels of 5 $\mu g/m^3$ and 0.3 $\mu g/m^3$, respectively, to determine if a project has a "potentially significant adverse impact." A project that exceeds either of these impact levels is then required to prepare an Environmental Impact Statement (EIS). NYSDEC is not the lead agency for SEQRA review for the Project, so CP-33 may not strictly apply. Nonetheless, a full EIS is being prepared for the Project and will include consideration of potential PM-2.5 impacts. In addition, NYSDEC appears to be using CP-33 to regulate PM-2.5 emissions until a State Implementation Plan (SIP) is created for PM-2.5. Under CP-33, if a project's maximum impacts are less than the project impact thresholds for PM-2.5, then the project is considered to have insignificant impacts for PM-2.5 and no further analysis of PM-2.5 is required. If a project has potentially significant impacts of PM-2.5, then air quality modeling results must be provided that show the maximum project impacts in the project area. In addition, community wide impacts showing the pattern of predicted impacts may be required. Based on the results of modeling conducted for PM-10 (see Table 5-3), it is concluded that the maximum Project impacts are below the CP-33 annual project impact threshold of 0.3 $\mu g/m^3$ but exceed the 24-hour threshold of 5.0 $\mu g/m^3$. Therefore, additional modeling for PM-2.5 was performed as discussed later in this section in order to provide information concerning the level and pattern of predicted Project PM-2.5 impacts.

In addition, for projects with potentially significant impacts of PM-2.5, an assessment of the severity of impacts, alternatives, and reasonable and necessary measures to minimize PM-2.5 emissions and impacts to the extent possible is required. In addition to the air quality modeling, potential project impacts due to secondary PM-2.5 formation must be addressed. This assessment must provide a quantitative measure of potential PM-2.5 precursor emissions and a qualitative discussion on potential secondary PM-2.5 formation and must demonstrate that the project will comply with all state and federal regulations and programs applicable to the emissions of PM-2.5 precursor pollutants. These additional requirements of CP-33 are being addressed in the EIS for the Project.

In order to assess the Project's potential contribution to ambient PM-2.5 concentrations, an air quality modeling analysis was prepared using procedures described in the revised Air Quality Modeling Protocol. This analysis assumed that the PM-2.5 emissions from the combustion turbine, auxiliary boiler, dew point fuel gas heater, emergency diesel fire pump, and emergency diesel generator would be equivalent to their respective PM-10 emissions.

The Project's maximum annual and 98th percentile (corresponding to the highest 8th high value) 24-hour predicted PM-2.5 impacts were determined and added to background PM-2.5 values for comparison to the NAAQS. Background air quality levels for PM-2.5 are discussed in Section 4.6 of the revised Air Quality Modeling Protocol. Background PM-2.5 levels of 10.8 $\mu g/m^3$ and 29.3 $\mu g/m^3$ were used for annual and 24-hour averaging periods, respectively, based on the average annual concentration and the average of the 98th percentile 24-hour values over the last three years (2005 through 2007) at the PM-2.5 monitor in Newburg, Orange County, New York.

The maximum predicted Project annual PM-2.5 impact was approximately 0.18 $\mu g/m^3$. This is less than the corresponding annual ambient threshold of 0.3 $\mu g/m^3$ in CP-33 for determining potentially significant impacts. The sum of the maximum predicted annual Project impact for PM-2.5 to background levels yields a total of 11.0 $\mu g/m^3$ which is below the corresponding annual standard of 15 $\mu g/m^3$.

The maximum predicted 24-hour Project PM-2.5 impact was 9.9 $\mu g/m^3$. This impact was predicted to occur in elevated terrain located a few km to the northwest. This exceeds the corresponding 24-hour ambient threshold of 5.0 $\mu g/m^3$ for determining potentially significant impacts under CP-33.

The predicted highest 8th-high 24-hour value, corresponding to the 98th percentile value, was 2.85 $\mu g/m^3$. The sum of the predicted 98th percentile 24-hour Project impact to background yields a value of 32.2 $\mu g/m^3$ which is below the corresponding 24-hour standard of 35 $\mu g/m^3$.

Table 5-7 provides a summary of maximum predicted Project PM-2.5 impacts. Table 5-8 compares the sum of Project PM-2.5 impacts and background to the corresponding NAAQS. Graphical plots showing the predicted maximum annual, maximum 24-hour, and high 8th-high 24-hour Project impacts of PM-2.5 are provided in figures in Appendix I.

Table 5-7: Maximum Project PM-2.5 Impacts

Averaging Time	Rank	Project Impact (ug/m^3)	X (km)	Y (km)	Time	Percentage of NAAQS
Annual	MAX	0.18	546.982	4584.747	2002	1.2
24-hour	MAX	9.89	545.446	4586.521	2005020724	28.3

Table 5-8: PM-2.5 Compliance Demonstration					
Averaging Time	**Rank**	**Project Impact (ug/m^3)**	**Background (ug/m^3)**	**Total Concentration (ug/m^3)**	**NAAQS (ug/m^3)**
24-hour	H8H	2.85	29.3	32.2	35
Annual	MAX	0.2	10.8	11.0	15
Note: H8H = high 8th high; corresponds to 98th percentile value					

5.5.6 Impacts of Air Toxics

An air quality modeling analysis was conducted for potential non-criteria pollutant emissions from the proposed combined cycle units, auxiliary boiler, fuel gas heaters, emergency diesel generator, and emergency diesel fire pump at the CPV Valley Energy Center. Each source was modeled individually using a unit emission rate, and impacts for particular pollutants were obtained by scaling by the respective emission rate. Maximum impacts from each source for each pollutant were then added together to yield estimates of total impacts for each pollutant. These estimates of total Project impacts are conservative since the individual maximum source impacts were not necessarily predicted to occur at the same time or location. Maximum annual impacts were based on the higher of combustion turbine contributions for gas firing for the entire year or a weighted average of impacts from gas and ULSD firing. The resulting upper bound estimates of impacts were compared to the NYSDEC's short-term guideline concentration (SGC) and annual guideline concentration (AGC), respectively, for each non-criteria pollutant. The NYSDEC SGCs and AGCs used in the analysis are those listed in the NYSDEC's DAR-1 (formerly Air Guide-1) tables that were most recently revised in September 2007.

Potential non-criteria pollutant emissions from the operation of the combustion turbines were quantified based on USEPA AP-42 emission factors with the exception of formaldehyde, which was based on California Air Resources Board (CARB) emissions test data that is more appropriate for advanced-technology DLN model units such as Class-F turbines, and ammonia and sulfuric acid, which were from vendor provided information. Potential non-criteria pollutant emissions from the auxiliary boiler and duct burner were based on emission factors from AP-42 Chapter 1.4 (July 1998) and Chapter 1.3 (September 1998), while potential non-criteria pollutant emissions from the fuel gas heater and emergency diesel engines were based on emission factors from AP-42 Chapter 1.4 (July 1998) and Chapter 3.3 (October 1996), respectively. Tables B-12 and B-13 in Appendix B provide additional details concerning potential emissions of non-criteria pollutants from Project sources.

Table 5-9 presents a summary of maximum predicted non-criteria pollutant impacts relative to the associated SGC and AGC values. Predicted Project impacts of non-criteria pollutants are all well below the associated SGC and AGC values. Therefore, it is concluded that Project impacts will comply with NYSDEC guideline concentrations for air toxics

Table 5-9: Non-Criteria Pollutant Impacts and NYSDEC Guideline Concentrations

	Maximum 1-hour Concentrations									Maximum Annual Concentrations								
	Aux. Boiler	Emerg. Diesel Gen	Diesel Fire Pump	Gas Heater	Maximum Turbine Impact	Maximum Turbine Impacts	*Maximum Total Impacts*	*Maximum Total Impacts*	*SGC Standard*	Aux. Boiler	Emerg. Diesel Gen	Diesel Fire Pump	Gas Heater	Maximum Turbine Impact	Maximum Turbine Impacts	*Maximum Total Impacts*	*Maximum Total Impacts*	*AGC Standard*
					Gas Firing	Oil Firing	Gas Firing	Oil Firing						Gas Firing	Oil Firing	Gas Firing	Gas/Oil Firing	
Non-Criteria Pollutants	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)	(ug/m3)
1,3-Butadiene	0.0E+00	4.5E-03	2.4E-03	0.0E+00	1.2E-03	3.8E-02	8.1E-03	4.5E-02	---	0.0E+00	1.3E-05	5.5E-06	0.0E+00	6.1E-06	1.5E-05	2.5E-05	4.0E-05	3.3E-02
1,4 - Dichlorobenzene	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	6.3E-02	0.0E+00	6.3E-02	---	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.7E-05	0.0E+00	2.7E-05	9.0E-02
2-Methylnapthalene	2.2E-06	0.0E+00	0.0E+00	1.5E-06	1.5E-05	0.0E+00	1.9E-05	3.7E-06	---	2.1E-08	0.0E+00	0.0E+00	1.8E-07	7.2E-08	0.0E+00	2.8E-07	2.7E-07	7.1E+00
3-Methylchloranthrene	1.6E-07	0.0E+00	0.0E+00	1.1E-07	1.2E-06	0.0E+00	1.4E-06	2.8E-07	2.2E+04	1.5E-09	0.0E+00	0.0E+00	1.4E-08	5.4E-09	0.0E+00	2.1E-08	2.0E-08	9.0E+01
Acrolein	0.0E+00	1.1E-02	5.6E-03	0.0E+00	1.9E-02	0.0E+00	3.5E-02	1.6E-02	1.9E-01	0.0E+00	3.2E-05	1.3E-05	0.0E+00	1.1E-04	0.0E+00	1.5E-04	1.4E-04	2.0E-02
Ammonia	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.5E+01	1.4E+01	1.5E+01	1.4E+01	2.4E+03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	7.5E-02	5.7E-03	7.5E-02	3.4E-02	1.0E+02
Anthracene	2.2E-07	2.2E-04	1.1E-04	1.5E-07	3.2E-04	1.9E-03	6.5E-04	2.2E-03	---	2.1E-09	6.5E-07	2.6E-07	1.8E-08	1.6E-06	7.4E-07	2.6E-06	3.2E-06	2.0E-02
Arsenic	1.8E-05	0.0E+00	0.0E+00	1.2E-05	1.3E-04	2.6E-02	1.6E-04	2.6E-02	---	1.7E-07	0.0E+00	0.0E+00	1.5E-06	6.0E-07	1.0E-05	2.3E-06	1.3E-05	2.3E-04
Barium	4.0E-04	0.0E+00	0.0E+00	2.7E-04	2.8E-03	0.0E+00	3.5E-03	6.7E-04	---	3.8E-06	0.0E+00	0.0E+00	3.4E-05	1.3E-05	0.0E+00	5.1E-05	4.9E-05	1.2E+00
Benz(a)anthracene	1.6E-07	1.9E-04	1.0E-04	1.1E-07	2.4E-04	6.1E-03	5.4E-04	6.4E-03		1.5E-09	5.8E-07	2.4E-07	1.4E-08	1.2E-06	2.4E-06	2.0E-06	4.4E-06	2.0E-02
Benzene	1.9E-04	1.1E-01	5.7E-02	1.3E-04	2.3E-01	1.3E-01	4.0E-01	2.9E-01	1.3E+03	1.8E-06	3.2E-04	1.3E-04	1.6E-05	1.3E-03	5.2E-05	1.8E-03	1.8E-03	1.3E-01
Benzo(a)pyrene	1.1E-07	2.2E-05	1.1E-05	7.5E-08	1.6E-04	0.0E+00	1.9E-04	3.3E-05	---	1.0E-09	6.5E-08	2.7E-08	9.2E-09	8.1E-07	0.0E+00	9.1E-07	8.5E-07	9.1E-04
Beryllium	1.1E-06	0.0E+00	0.0E+00	7.5E-07	7.7E-06	7.3E-04	9.5E-06	7.3E-04	1.0E+00	1.0E-08	0.0E+00	0.0E+00	9.2E-08	3.6E-08	2.9E-07	1.4E-07	4.3E-07	4.2E-04
Butane	1.9E-01	0.0E+00	0.0E+00	1.3E-01	1.3E+00	0.0E+00	1.7E+00	3.2E-01	---	1.8E-03	0.0E+00	0.0E+00	1.6E-02	6.3E-03	0.0E+00	2.4E-02	2.4E-02	5.7E+04
Cadmium	1.0E-04	0.0E+00	0.0E+00	6.8E-05	7.1E-04	1.1E-02	8.7E-04	1.1E-02	---	9.5E-07	0.0E+00	0.0E+00	8.4E-06	3.3E-06	4.5E-06	1.3E-05	1.7E-05	2.4E-04
Carbon Tetrachloride	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	6.5E-02	0.0E+00	6.5E-02	1.9E+03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.8E-05	0.0E+00	2.8E-05	6.7E-02
Chlorobenzene	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	5.3E-02	0.0E+00	5.3E-02	---	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.3E-05	0.0E+00	2.3E-05	1.1E+02
Chloroform	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	5.4E-02	0.0E+00	5.4E-02	1.5E+02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.3E-05	0.0E+00	2.3E-05	4.3E-02
Chromium	1.3E-04	0.0E+00	0.0E+00	8.7E-05	9.0E-04	2.6E-02	1.1E-03	2.6E-02	---	1.2E-06	0.0E+00	0.0E+00	1.1E-05	4.2E-06	1.0E-05	1.6E-05	2.6E-05	1.2E+00
Chrysene	1.6E-07	4.1E-05	2.1E-05	1.1E-07	2.4E-04	3.6E-03	3.0E-04	3.7E-03	---	1.5E-09	1.2E-07	5.0E-08	1.4E-08	1.2E-06	1.5E-06	1.4E-06	2.8E-06	2.0E-02
Cobalt	7.6E-06	0.0E+00	0.0E+00	5.2E-06	5.4E-05	0.0E+00	6.7E-05	1.3E-05	---	7.2E-08	0.0E+00	0.0E+00	6.4E-07	2.5E-07	0.0E+00	9.7E-07	9.4E-07	1.0E-03
Copper	7.7E-05	0.0E+00	0.0E+00	5.3E-05	5.5E-04	0.0E+00	6.8E-04	1.3E-04	1.0E+02	7.3E-07	0.0E+00	0.0E+00	6.5E-06	2.6E-06	0.0E+00	9.8E-06	9.6E-06	2.0E-02
Dibenzo(a,h)anthracene	1.1E-07	6.7E-05	3.5E-05	7.5E-08	1.6E-04	2.5E-03	2.6E-04	2.6E-03	---	1.0E-09	2.0E-07	8.2E-08	9.2E-09	8.1E-07	1.0E-06	1.1E-06	2.1E-06	2.0E-02
Dichlorobenzene	1.1E-04	0.0E+00	0.0E+00	7.5E-05	7.7E-04	0.0E+00	9.5E-04	1.8E-04	---	1.0E-06	0.0E+00	0.0E+00	9.2E-06	3.6E-06	0.0E+00	1.4E-05	1.3E-05	9.0E-02
Ethane	2.8E-01	0.0E+00	0.0E+00	1.9E-01	2.0E+00	0.0E+00	2.5E+00	4.7E-01	---	2.7E-03	0.0E+00	0.0E+00	2.4E-02	9.3E-03	0.0E+00	3.6E-02	3.5E-02	2.9E+03
Ethylbenzene	0.0E+00	0.0E+00	0.0E+00	0.0E+00	9.0E-02	0.0E+00	9.0E-02	0.0E+00	5.4E+04	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.6E-04	0.0E+00	4.6E-04	4.2E-04	1.0E+03
Ethylene Dichloride	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.3E-02	0.0E+00	4.3E-02	---	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.8E-05	0.0E+00	1.8E-05	3.8E-02
Formaldehyde	6.8E-03	1.4E-01	7.2E-02	4.7E-03	3.5E-01	6.6E-01	5.7E-01	8.8E-01	3.0E+01	6.4E-05	4.1E-04	1.7E-04	5.7E-04	1.6E-03	2.7E-04	2.8E-03	2.9E-03	6.0E-02
Hexane	1.6E-01	0.0E+00	0.0E+00	1.1E-01	1.2E+00	0.0E+00	1.4E+00	2.8E-01	---	1.5E-03	0.0E+00	0.0E+00	1.4E-02	5.4E-03	0.0E+00	2.1E-02	2.0E-02	7.0E+02
Lead	4.5E-05	0.0E+00	0.0E+00	3.1E-05	3.2E-04	3.3E-02	4.0E-04	3.3E-02	---	4.3E-07	0.0E+00	0.0E+00	3.8E-06	1.5E-06	1.3E-05	5.7E-06	1.9E-05	3.8E-01
Manganese	3.4E-05	0.0E+00	0.0E+00	2.4E-05	2.4E-04	1.9E+00	3.0E-04	1.9E+00	---	3.3E-07	0.0E+00	0.0E+00	2.9E-06	1.1E-06	7.5E-04	4.4E-06	7.5E-04	5.0E-02
Mercury	2.4E-05	0.0E+00	0.0E+00	1.6E-05	1.7E-04	2.8E-03	2.1E-04	2.9E-03	1.8E+00	2.2E-07	0.0E+00	0.0E+00	2.0E-06	7.8E-07	1.1E-06	3.0E-06	4.1E-06	3.0E-01
Methylene Chloride	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.5E-02	0.0E+00	4.5E-02	1.4E+04	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.9E-05	0.0E+00	1.9E-05	2.1E+00
Molybdenum	1.0E-04	0.0E+00	0.0E+00	6.8E-05	7.1E-04	0.0E+00	8.7E-04	1.7E-04	---	9.5E-07	0.0E+00	0.0E+00	8.4E-06	3.3E-06	0.0E+00	1.3E-05	1.2E-05	1.2E+00
Nickel	1.9E-04	0.0E+00	0.0E+00	1.3E-04	1.3E-03	3.4E-02	1.7E-03	3.5E-02	6.0E+00	1.8E-06	0.0E+00	0.0E+00	1.6E-05	6.3E-06	1.5E-05	2.4E-05	3.8E-05	4.2E-03
PAH	0.0E+00	0.0E+00	0.0E+00	0.0E+00	6.2E-03	9.4E-02	6.2E-03	9.4E-02	---	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.1E-05	3.8E-05	3.1E-05	6.7E-05	2.0E-02
Pentane	2.4E-01	0.0E+00	0.0E+00	1.6E-01	1.7E+00	0.0E+00	2.1E+00	4.0E-01	---	2.2E-03	0.0E+00	0.0E+00	2.0E-02	7.8E-03	0.0E+00	3.0E-02	2.9E-02	4.2E+03
Phenanathrene	1.5E-06	3.4E-03	1.8E-03	1.1E-06	2.3E-03	1.6E-02	7.4E-03	2.1E-02	---	1.5E-08	1.0E-05	4.2E-06	1.3E-07	1.1E-05	6.4E-06	2.6E-05	3.1E-05	2.0E-02
Propane	1.5E-01	0.0E+00	0.0E+00	9.9E-02	1.0E+00	0.0E+00	1.3E+00	2.4E-01	---	1.4E-03	0.0E+00	0.0E+00	1.2E-02	4.8E-03	0.0E+00	1.8E-02	1.8E-02	4.3E+04
Propylene	0.0E+00	3.0E-01	1.6E-01	0.0E+00	0.0E+00	0.0E+00	4.5E-01	4.5E-01	---	0.0E+00	8.9E-04	3.6E-04	0.0E+00	0.0E+00	0.0E+00	1.3E-03	1.3E-03	3.0E+03
Propylene Oxide	0.0E+00	0.0E+00	0.0E+00	0.0E+00	8.2E-02	0.0E+00	8.2E-02	0.0E+00	3.1E+03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.1E-04	0.0E+00	4.1E-04	3.8E-04	2.7E-01
Pyrene	4.5E-07	5.5E-04	2.9E-04	3.1E-07	6.7E-04	6.5E-03	1.5E-03	7.3E-03	---	4.3E-09	1.7E-06	6.8E-07	3.8E-08	3.4E-06	2.6E-06	5.7E-06	8.1E-06	2.0E-02
Selenium	2.2E-06	0.0E+00	0.0E+00	1.5E-06	1.5E-05	6.1E-02	1.9E-05	6.1E-02	---	2.1E-08	0.0E+00	0.0E+00	1.8E-07	7.2E-08	2.6E-05	2.8E-07	2.7E-05	2.0E+01
Sulfuric Acid	1.6E-02	7.0E-02	3.7E-02	1.1E-02	1.9E+00	1.1E+00	2.0E+00	1.2E+00	1.2E+02	1.5E-04	2.1E-04	8.5E-05	1.3E-03	9.5E-03	4.4E-04	1.1E-02	1.1E-02	1.0E+00
Tetrachloroethylene	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	6.9E-02	0.0E+00	6.9E-02	1.0E+03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.0E-05	0.0E+00	3.0E-05	1.0E+00
Toluene	3.1E-04	4.7E-02	2.5E-02	2.1E-04	3.7E-01	0.0E+00	4.4E-01	7.2E-02	3.7E+04	2.9E-06	1.4E-04	5.8E-05	2.6E-05	1.9E-03	0.0E+00	2.1E-03	1.9E-03	5.0E+03
Trichloroethylene	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	5.9E-02	0.0E+00	5.9E-02	1.4E+04	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.5E-05	0.0E+00	2.5E-05	5.0E-01
Vanadium	2.1E-04	0.0E+00	0.0E+00	1.4E-04	1.5E-03	0.0E+00	1.8E-03	3.5E-04	---	2.0E-06	0.0E+00	0.0E+00	1.8E-05	6.9E-06	0.0E+00	2.6E-05	2.6E-05	2.0E-01
Vinyl Chloride	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.1E-01	0.0E+00	1.1E-01	1.8E+05	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.8E-05	0.0E+00	4.8E-05	1.1E-01
Vinylidene Chloride	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.3E-02	0.0E+00	4.3E-02	---	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.8E-05	0.0E+00	1.8E-05	7.0E+01
Xylenes	0.0E+00	3.3E-02	1.7E-02	0.0E+00	1.8E-01	0.0E+00	2.3E-01	5.0E-02	4.3E+03	0.0E+00	9.8E-05	4.0E-05	0.0E+00	9.1E-04	0.0E+00	1.1E-03	9.8E-04	1.0E+02
Zinc	2.6E-03	0.0E+00	0.0E+00	1.8E-03	1.9E-02	0.0E+00	2.3E-02	4.4E-03	---	2.5E-05	0.0E+00	0.0E+00	2.2E-04	8.7E-05	0.0E+00	3.3E-04	3.3E-04	4.5E+01

5.6 Additional Impact Analyses

The following subsections present the results of additional analyses conducted to assess potential impacts to soils and vegetation, potential impacts on visibility in Class I areas, potential impacts on visibility in Catskills State Park, and a discussion concerning potential impacts on industrial, commercial and residential growth.

5.6.1 Impacts to Soils and Vegetation

PSD review requirements include an analysis to determine the potential air quality impacts on sensitive vegetation types that may be present in the vicinity of the proposed project. The evaluation of potential impacts on vegetation was conducted in accordance with A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, (USEPA, 1980). Calculated air quality concentrations of various constituents from the proposed project are added to ambient background concentrations and compared to screening concentrations (levels at which change has been reported) to provide an assessment regarding the potential for adversely impacting vegetation with significant commercial and/or recreational value.

Screening concentrations used in this assessment represent the minimum ambient concentrations reported in the scientific literature for which adverse effects (e.g., visible damage or growth retardation) to plants have been reported. Of the potential pollutants generated by the proposed project, vegetative screening concentrations are available for SO_2, NO_2, and CO. Screening concentrations for other potential constituents generated by the facility (e.g., particulate matter) are not currently available. Table 5-10 presents a comparison of the maximum modeled concentrations plus background to the screening concentrations. Inspection of the table reveals that the proposed CPV Valley Energy Center would not adversely impact vegetation in the site area.

Table 5-10: Comparison of Maximum Predicted Concentrations of Pollutants to Vegetation Screening Concentrations

Pollutant	Averaging Period	Maximum Modeled Ground-Level Concentration ($\mu g/m^3$)	Background[1] Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Vegetation Screening Concentrations ($\mu g/m^3$)		
					Sensitive	Intermediate	Resistant
CO	1-week	181.9[2]	3,206[2]	3,387	1,800,000	--	18,000,000
SO_2	1-hour	7.3	76[5]	83	917	--	--
	3-hour	3.2	55[5]	58	786	2,096	13,100
NO_2	4-hour	217[3]	214[4]	431	3,760	9,400	16,920
	8-hour	217[3]	214[4]	431	3,760	7,520	15,040
	Annual	0.14	41	41	--	94	--

Notes:

[1] Background concentrations represent the highest second-highest short term (1-, 3-, 8-, and 24-hour) and maximum annual concentrations recorded during the latest three years of available monitoring data (2005-2007 for CO and SO_2 and 2004-2006 for NO_2). See Table 4-4 of the revised Air Quality Modeling Guideline for more information concerning sources of monitoring data.

[2] Maximum modeled and background concentrations conservatively based on 8-hour averaging period. Factor of 1,145 $\mu g/m^3$ per ppm used to convert ppm background values for CO.

[3] Maximum modeled concentration conservatively based on sum of individual maximum source 3-hour predicted impacts unpaired in time or space and accounts for higher startup emissions from combustion turbines.

[4] Maximum background concentration conservatively based on 1-hour averaging period. Factor of 1,880 $\mu g/m^3$ per ppm used to convert ppm background values for NO_2.

[5] Factor of 2,620 $\mu g/m^3$ per ppm used to convert ppm background values for SO_2.

5.6.2 Class I Area Impacts

There are no Class I areas located within 100 km of the Project site. The closest Class I area to the Project is the Brigantine Wilderness Area in New Jersey. The closest portion of the Brigantine Wilderness Area is approximately 206 km from the Project site. The next closest Class I area is the Lye Brook Wilderness Area in Vermont. The closest portion of this area is approximately 215 km from the Project site. Other Class I areas are well beyond 300 km from the Project site.

Given the potential to emit of the Project and the distance to the nearest Class I areas, it is expected that the Project will qualify for an exemption from potential Class I impact modeling requirements for air quality related values (AQRVs) and visibility. The Project has consulted with the Federal Land Managers for the nearest Class I areas to request a determination that the Project would be exempt from any Class I modeling requirement. Copies of the consultation letters to the respective Federal Land Managers are included in Appendix C.

Even though the Project will likely be exempt from the need for any Class I impact modeling, a Level-1 screening analysis for impacts on visibility was conducted using procedures described in USEPA's Workbook for Plume Visual Impact Screening and Analysis (USEPA, 1988). The screening procedure involves calculation of three plume contrast coefficients using emissions of NO_x, 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. The analysis was run assuming that all emitted particulate would be PM-10, which results in a conservative assessment of visibility impacts. Those coefficients consider plume/sky contrast, plume/terrain contrast, and sky/terrain contrast.

The Level-1 screening analysis using the USEPA VISCREEN (Version 1.01) model was performed for the worst possible operating scenario, i.e., the scenario with the highest emission rates of NOx, PM/PM-10, and H2SO4 corresponding to ULSD firing in the combustion turbines. The resulting visibility impacts inside the Brigantine Wilderness Area and the Lye Brook Wilderness Area due to maximum proposed emissions from the Project were compared to the established Class I default screening thresholds of 2.00 for plume perceptibility (Delta-E) and 0.05 for plume contrast.

The VISCREEN analysis was conducted using the standard Level-1 default parameters. A visual range of 159 km for Brigantine Wilderness Area and 195 km for Lye Brook Wilderness Area were used based on the annual average of monthly natural conditions visual range values provided in Table V.1-6 of the June 2008 draft "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report – Revised."

The results, presented in Tables 5-11 and 5-12 for Brigantine Wilderness Area and Lye Brook Wilderness Area, respectively, show that predicted visibility impacts are below the Class I default screening thresholds for plume perceptibility and plume contrast. Therefore, it is concluded that the Project will have no significant effect on visibility in Class I areas. Copies of the VISCREEN output files are provided in Appendix J.

Table 5-11: VISCREEN Maximum Class I Visual Impacts – Brigantine Wilderness Area[1]								
Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E[2]		Contrast[3]	
					Criteria	Plume	Criteria	Plume
Inside Surrounding Area								
Sky	10	84	206	84	2.0	0.493	0.05	0.007
Sky	140	84	206	84	2.0	0.107	0.05	-0.004
Terrain	10	84	206	84	2.0	0.275	0.05	0.003
Terrain	140	84	206	84	2.0	0.050	0.05	0.001
Outside Surrounding Area								
Sky	10	5	64.2	164	2.0	0.790	0.05	0.007
Sky	140	5	64.2	164	2.0	0.189	0.05	-0.004
Terrain	10	5	64.2	164	2.0	0.366	0.05	0.003
Terrain	140	5	64.2	164	2.0	0.137	0.05	0.003

Notes:

[1] Based on the total project emissions.
[2] Color difference parameter (dimensionless).
[3] Visual contrast against background parameter (dimensionless).

Table 5-12: VISCREEN Maximum Class I Visual Impacts – Lye Brook Wilderness Area[1]								
Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E[2]		Contrast[3]	
					Criteria	Plume	Criteria	Plume
Inside Surrounding Area								
Sky	10	84	215	84	2.0	0.647	0.05	0.010
Sky	140	84	215	84	2.0	0.130	0.05	-0.005
Terrain	10	84	215	84	2.0	0.411	0.05	0.004
Terrain	140	84	215	84	2.0	0.064	0.05	0.002
Outside Surrounding Area								
Sky	10	5	67	164	2.0	1.519	0.05	0.015
Sky	140	5	67	164	2.0	0.333	0.05	-0.007
Terrain	10	5	67	164	2.0	0.649	0.05	0.005
Terrain	140	5	67	164	2.0	0.250	0.05	0.005

Notes:

[1] Based on the total project emissions.
[2] Color difference parameter (dimensionless).
[3] Visual contrast against background parameter (dimensionless).

5.6.3 Impact on Visibility – Catskills State Park

In response to comments from NYSDEC, a visibility impact analysis was conducted for the Catskills State Park. Class II areas are not subject to the stringent protection that is provided to Class I areas. Nonetheless, potential impacts on visibility due to Project emissions were assessed for those locations in the Catskills State Park for which impacts from Project plumes would be most likely to be discerned (i.e., from prominent elevation peaks). The analysis considered locations associated with all high peaks (those with elevations equal to or greater than 3500 feet MSL) in the Catskills State Park as identified on the Catskills GIS website). The high peaks in Catskills State Park are listed in Table 5-13.

A Level-1 screening analysis for impacts on local visibility was performed using the USEPA VISCREEN (Version 1.01) model for the worst possible operating scenario corresponding to ULSD firing in the combustion turbines. The analysis assumed an observer would be present at the nearest high peak to the Project and considered distances corresponding to the nearest and most distant peaks in the Catskills State Park relative to the Project. A background visual range of 40 km was assumed consistent with recommended values provided in Figure 4-3 of USEPA's "Tutorial Package for the VISCREEN Model."

The results of this analysis are presented in Table 5-14. The predicted visibility impacts as observed from high peaks in the Catskills State Park were compared to the stringent Class I screening thresholds even though these thresholds do not apply in Class II areas. The predicted impacts were below the Class I screening thresholds, indicating that the Project would not impact visibility in the Class II areas in the Catskills State Park. Copies of the VISCREEN output files are included in Appendix J.

Table 5-13: Catskills State Park -- High Peaks			
Peak Name	**Elevation (feet MSL)**	**USGS Map Name**	**Distance (km)**
Peekamoose	3843	Peekamoose Mountain	60
Table	3847	Peekamoose Mountain	61
Lone	3721	Peekamoose Mountain	62
Rocky	3508	West Shokan	62
Balsam Cap	3623	West Shokan	63
Friday	3694	West Shokan	64
Cornell	3860	Phoenicia	66
Wittenberg	3780	Phoenicia	67
Slide	4180	Peekamoose Mountain	65
Panther	3720	Shandaken	72
Fir	3620	Shandaken	68
Big Indian	3700	Shandaken	69
Double Top	3860	Seager	69
Graham	3868	Seager	70
Balsam Lake	3723	Seager	72
Eagle	3600	Seager	72
Balsam	3600	Shandaken	75
Indian Head	3573	Woodstock	83
Twin	3640	Bearsville	83
Sugarloaf	3800	Hunter	83
Plateau	3840	Hunter	88
Kaaterskill High Peak	3655	Kaaterskill	88
Southwest Hunter	3740	Hunter	85
Hunter	4040	Hunter	87
West Kill	3880	Lexington	85
Rusk	3680	Lexington	88
North Dome	3610	Lexington	85
Sherrill	3540	Lexington	85
Halcott	3537	West Kill	85
Thomas Cole	3840	Hensonville	99
Black Dome	3980	Freehold	99
Blackhead	3940	Freehold	99
Windham High Peak	3524	Hensonville	103

Notes:

1. Information on Catsill peak heights and locations obtained from Catskills GIS Atlas website: http://www.catskillcenter.org/atlas/geomorphology/geo_2_3dhighpeaks.htm

Table 5-14: VISCREEN Maximum Catskills State Park Class II Visual Impacts[1]								
Background	**Theta (degrees)**	**Azimuth (degrees)**	**Distance (km)**	**Alpha (degrees)**	**Delta E[2]**		**Contrast[3]**	
					Criteria	**Plume**	**Criteria**	**Plume**
Inside Surrounding Area								
Sky	10	84	60	84	2.0	1.071	0.05	0.011
Sky	140	84	60	84	2.0	0.261	0.05	-0.009
Terrain	10	84	60	84	2.0	0.554	0.05	0.007
Terrain	140	84	60	84	2.0	0.1132	0.05	0.005
Outside Surrounding Area								
Sky	10	30	45.5	139	2.0	1.286	0.05	0.013
Sky	140	30	45.5	139	2.0	0.236	0.05	-0.011
Terrain	10	45	51.0	124	2.0	0.710	0.05	0.008
Terrain	140	45	51.0	124	2.0	0.157	0.05	0.006

Notes:

[1] Based on the total project emissions.

[2] Color difference parameter (dimensionless).

[3] Visual contrast against background parameter (dimensionless).

5.6.4 *Impacts on Industrial, Commercial and Residential Growth*

The proposed project's location within an industrial area would result in minimal impact to services, existing land uses, and infrastructure. The Project would utilize natural gas as the primary fuel with provisions to use low sulfur distillate fuel oil for up to the equivalent of 720 hours per combustion turbine as a back-up fuel. It is contemplated that natural gas supply would be provided by a new natural gas pipeline lateral developed by Millennium or Orange & Rockland Gas Company. To accommodate short-term operation on oil, the proposed project would include a 965,000-gallon fuel storage tank and associated off-loading facilities, transfer piping, and pump systems. Both fuels would be used for the efficient production of electricity. The Project would interconnect to NYPA's 345-kilovolt (kV) transmission system, less than one mile from the Facility via a newly constructed 345 kV switchyard on site and overhead and underground electric transmission lines. The new switchyard would be located in the western portion of the 122-acre parcel. The preferred interconnection to the 345 kilovolt (kV) NYPA Marcy South system would be made via a new on-site 345kV substation, with above ground 345 kV transmission lines on site, and underground 345kV electric transmission cables offsite.

The preferred route is via five overhead steel transmission monopoles on a 150 foot on-site wide right-of-way, before the line transitions onsite to an underground duct bank configuration on the west side of Route 17M. The underground duct bank will be 4 feet wide and will be located off pavement primarily within the western drainage swale, within the right-of-way of NY Route 17M. The duct bank will terminate next to a riser pole on or next to NYPA's Marcy South transmission right of way, just north of the intersection of NY Routes 6 and 17M.

The existing roads and services would easily be able to handle the 25 person workforce, which would be spread over 3 shifts. There would not be significant in-migration to the Wawayanda area. Therefore, there is no expected incremental increase of municipal service costs attributed to the operations employees. Field construction activities are expected to have a duration of approximately 26 months.

The Project is designed to result in low emission levels of air contaminants. The electricity generated by the Project would be directed to the power distribution system in the lower Hudson Valley Area. Finally, since the air emissions from the Project are predicted to result in insignificant impacts of all pollutants (except for PM-10 during limited oil firing conditions in the turbines), new industry desiring to locate in the area would not be prohibited due to unacceptable air pollution levels caused by the proposed plant. Therefore, the proposed project should have no effect on either existing or future industrial, commercial, or residential growth in the region.

6.0 ENVIRONMENTAL JUSTICE

6.1 Introduction

This environmental justice (EJ) analysis is designed to determine whether the construction and operation of the proposed Project would have a significant adverse and disproportionate affect on an "environmental justice community." The concept of performing an EJ analysis for the Project is related to the issuance of Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations" (February 11, 1994). The order requires Federal agencies to consider disproportionate adverse human health and environmental impacts on minority and low-income populations. The methodology used in preparing this analysis is based upon the New York State Department of Environmental Conservation (NYSDEC) EJ Policy (CP-29, Environmental Justice and Permitting, March 19. 2003) and Federal guidance documents prepared by USEPA for use in preparing a National Environmental Policy Act (NEPA) environmental justice analysis. The NYSDEC EJ Policy provides guidance on how environmental justice consideration can be incorporated into permit review, SEQRA procedures, and some components of the NYSDEC's enforcement and public participation programs.

The NYSDEC EJ policy applies to major projects as defined in 6 NYCRR Part 621.4. The Project requires a Part 201 permit and is considered a major Project.

The NYSDEC EJ Policy prescribes a two-step methodology for conducting the preliminary screening analysis. These steps consist of:

- Determining whether the proposed action is in or near a minority or low-income community and identify potential environmental impacts.
- Determining whether impacts are likely to adversely affect a potential EJ community.

The focus of an EJ analysis is the determination of whether the construction and operation of a proposed Project would have both adverse and disproportionate impacts on an environmental justice community. The EIS being prepared for the Project will demonstrate that the impacts of the Project would not be considered to be "adverse" under any Federal, state, or local guideline or standard. Nonetheless, an environmental impact analysis was conducted to determine whether there would be an adverse and disproportionate environmental burdens on minority or low-income populations as defined in the NYSDEC EJ Policy.

6.2 Determination of Environmental Justice Communities

The NYSDEC EJ Policy establishes state-specific thresholds in order to identify areas, typically census tracts or block groups, where the representation of low-income and/or minority populations qualifies the area as a "potential environmental justice area." The NYSDEC EJ Policy establishes the New York State urban EJ threshold for minority population at 51.1 percent. For purposes of this policy, an urban threshold applies because the area in question is located within a Census-designated place with a population of 2,500 people or more. The Town of Wawayanda proper has a small minority population of 10.6 percent.

The NYSDEC EJ Policy establishes the New York State EJ threshold for low-income population at 23.59 percent. Income data are part of the US Census "long form" questionnaire and are based on a partial, sample count. For the year 2000 Census, low-income population is defined as the percentage of individuals whose 1999 income was less than 100 percent of the poverty level. Block groups in which more than 23.59 percent of individuals fit this description are potential EJ communities. In the Town of Wawayanda, only 3.7 percent of the population was living below the poverty threshold. Table 6-1 provides a summary of percent minority, poverty rate, and household income data for each Census block group within a two mile radius of the Project site, as well as six Census block groups outside the 2-mile radius that have been identified by NYSDEC as potential EJ sites. Figure 6-1 shows the location of the each Census Block relative to the Project site.

Table 6-1: Environmental Justice Data by Census Block Group			
Area	**Minority Population Percentage**	**Poverty Rate**	**Median Household Income**
New York State	39.5	14.6	$43,393
Orange County	28.6	10.5	$52,058
Wawayanda	10.6	3.7	$61,885
Tract 11, BG 4*	**53.1**	21.9	$27,548
Tract 14, BG 2*	49.0	**39.3**	$14,500
Tract 14, BG 3*	**60.1**	**34.7**	$18,424
Tract 14, BG 6*	**55.4**	**31.7**	$26,786
Tract 15, BG 1*	**57.6**	22.0	$32,292
Tract 15, BG 3	**62.29**	**26.76**	$22,768
Tract 16, BG 1	36.63	12.31	$43,403
Tract 16, BG 2	36.42	6.95	$51,139
Tract 16, BG 3	31.10	5.92	$43,750
Tract 16, BG 4	39.70	6.09	$50,714
Tract 17, BG 1*	**56.7**	**31.4**	$15,341
Tract 112, BG 3	35.00	4.13	$49,450
Tract 114, BG 3	15.37	1.33	$60,536
Tract 118, BG 1	12.12	1.16	$67,417
Tract 118, BG 2	12.43	3.04	$61,250
Tract 118, BG 3	10.89	2.41	$68,942
Tract 118, BG 4	11.40	5.51	$53,021
Tract 118, BG 5	7.25	6.13	$55,809

Notes: BG: Block Group
The NYSDEC minority population percentage threshold in urban areas is 51.1 percent
The NYSDEC poverty rate threshold is 23.59 percent
Bold values indicate percentage above the NYSDEC threshold
* DEC-identified potential EJ area outside 2-mile radius

Sources: U.S. Census, 2000 and Empire State Development Website

The Town of Wawayanda's minority population (10.6 percent) and poverty rate (3.7 percen) are well below the NYSDEC's population percentage threshold for minority populations and the population percentage threshold for low income[4]. As shown in Table 6-1, one out of the twelve census block groups within a two-mile radius of the Project is a potential Environmental Justice Area. This Census Block (Tract 15, BG 3) is primarily located in the City of Middletown; a small

[4] Minority and income data were obtained from the 2000 Census.

portion is located in Walkill. The southwestern most point of the census block is 0.94 miles northeast from the Facility Site..

The NYSDEC identified six potential EJ areas outside the 2-mile radius (Tract 11, BG 4; Tract 14, BG 2; Tract 14, BG 3; Tract 14, BG 6; Tract 15, BG 1; and Tract 17, BG 1.). These additional EJ areas are included in the EJ analysis.

In addition, a workforce housing project called "Horizons at Wawayanda" is located adjacent to Project site to the northwest of the Project site. Horizons at Wawayanda consists of 106 dwelling units, and is approximately 0.40 miles from where the Project will sit on the site. Construction at this site is nearing completion and applications are being accepted for fall 2008 occupancy. Horizons at Wawayanda is a project built with a combination of private and public funding to develop affordable housing for Orange County's working families at below market rates. Horizons at Wawayanda was constructed on a formerly vacant parcel adjacent to a cemetery, commercial, and industrial properties and directly bordering the MI Zoning District.

6.3 EJ Area Impact Assessment

The Project was modeled in accordance with the procedures documented in the revised Air Quality Modeling Protocol, and maximum predicted Project impacts were determined for various pollutants and averaging periods.

Table 6-2 presents the maximum predicted impacts of CO, SO_2, PM-10, and NO_2 for comparison with significant impact levels (SILs) that have been established by EPA. Table 6-2 also presents the sum of maximum Project impacts and conservative background air quality levels so that total predicted concentrations can be compared to the corresponding National Ambient Air Quality Standards (NAAQS).

All predicted Project impacts, except for 24-hour average PM-10 impacts, are below SILs. The sum of maximum predicted impacts and conservative background levels is below the corresponding NAAQS for all pollutants and averaging periods. Therefore, the Project is not considered to have any adverse air quality impacts

Figures in Appendix K provide isopleth plots of maximum predicted Project impacts for each pollutant and averaging period. The outlines of identified EJ areas and the Project location are also depicted on the plots.

The maximum predicted Project impacts for short-term averaging periods are generally predicted to occur in elevated terrain located to the northwest of the Project in a direction away from identified EJ areas. Therefore, the identified EJ areas will not receive a disproportionate share of the maximum short-term Project impacts.

The maximum predicted annual Project impacts exhibit a pattern that reflects the general southwest/northeast orientation of the surrounding terrain and the corresponding prevailing winds. Although some of the maximum annual Project impacts are predicted to occur near some of the nearest EJ areas or, in some cases, near the Project fence line, the maximum predicted annual impacts are always below the corresponding SIL, so there will be no adverse impact from the Project.

Table 6-2: Maximum Predicted Project Impacts a/						
Pollutant	**Averaging Period**	**SIL ($\mu g/m^3$)**	**NAAQS ($\mu g/m^3$)**	**Background Concentration b/ ($\mu g/m^3$)**	**Maximum Ground-Level Project Impact ($\mu g/m^3$)**	**Total Ground-Level Concentration c/ ($\mu g/m^3$)**
CO	1-Hour	2,000	40,000	3,893	563	4,456
	8-Hour	500	10,000	3,206	182	3,382
SO_2	3-Hour	25	1,300	55.0	3.3	58
	24-Hour	5	365	28.8	0.6	29
	Annual	1	80	5.2	0.04	5.2
PM_{10}	24-Hour	5	150	78	9.9	88
	Annual	1	50	35	0.2	35
NO_2	Annual	1	100	41.4	0.8	42

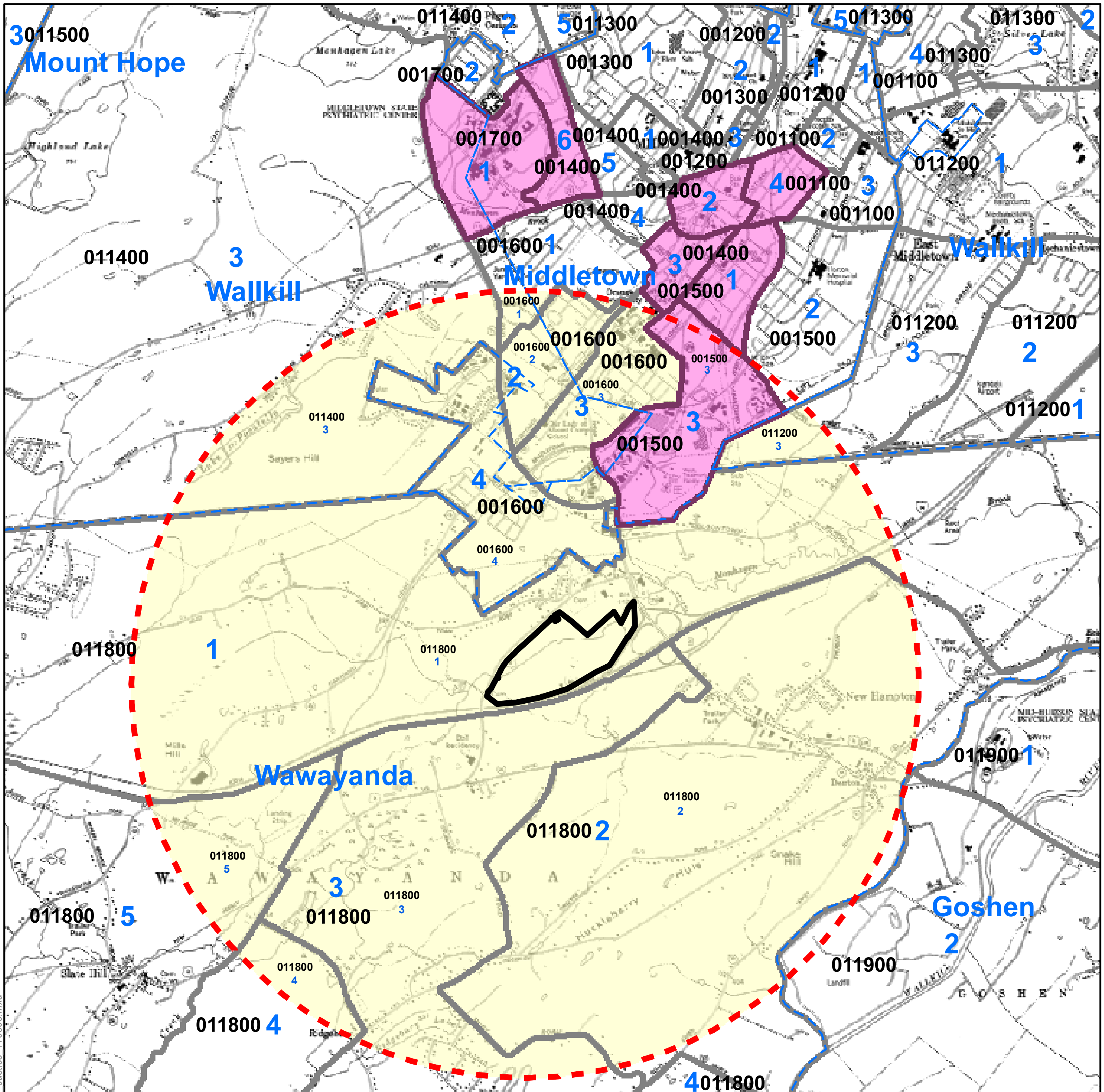
Notes:

a/ Maximum modeled ground-level concentration due to the worst case overall facility operating scenario (i.e., the facility operating scenario that resulted in the maximum modeled air quality impact) for each pollutant.

b/ Background concentrations are the highest second highest short term (1-, 3-, 8-, and 24-hour) and maximum annual concentrations.

c/ Total concentration = background concentration + maximum modeled (i.e., ground-level) concentration.

Source: TRC Environmental Corp.



Block Group Exceeds NYSDEC Poverty Rate Threshold of 23.59% and Minority Population Percentage Threshold of 51.1%

Block Group Does Not Exceed NYSDEC Poverty Rate Threshold of 23.59% and Minority Population Percentage Threshold of 51.1%

011800 Census Tract Number

2 Census Block Group

Census Block Groups

2 Mile Radius

DEC Environmental Justice Areas

CPV Valley Site

Town Boundaries

Source Data: U.S.Census 2000, Empire State Development Website
Base Map: New York Department of Transportation

0 0.5 1 Miles

N

CPV VALLEY ENERGY CENTER
WAWAYANDA, NEW YORK

ENVIRONMENTAL JUSTICE SCREENING AREA, POVERTY RATE, MINORITY POPULATION MAP

TRC
Wannalancit Mills
650 Suffolk Street
Lowell, MA 01854
978-970-5600

NOVEMBER, 2008

FIGURE 6-1

R:\Projects\GIS_2007\150338_Wawayanda\mxd\SEQR\Env_Justice\FIG_7-2_Env_Justice_110308.mxd

7.0 CONSTRUCTION RELATED ACTIVITIES

Project related air quality impacts during the construction phase are expected to include fugitive dust emissions and vehicle emissions from ground excavation, cut-and-fill operations, removal of debris, concrete pouring, and equipment erection. However, because the construction period is limited and activities change during the construction phases, these emissions are only temporary and vary throughout this period.

Emissions of fugitive dust will depend on such factors as soil properties (i.e., moisture content, volume of spoils, and soil silt content), meteorological variables, and construction practices employed. For airborne particulates such as fugitive dust the NYSDOT recommends the use of control measures to minimize these emissions. Consistent with the NYSDOT's Environmental Procedures Manual, emissions of fugitive dust will be mitigated using the following measures:

- Water or other wetting agents on areas of exposed and dry soils;
- Covered trucks for soils and other dry materials;
- Controlled storage of spoils on the construction site; and
- Final grading and landscaping of exposed areas as soon as possible.

The NYSDOT reports that such measures have "proved effective" in limiting fugitive dust during the construction period.

Emissions from vehicles will include onsite equipment and those from construction workers. As noted in the NYSDOT's Environmental Procedures Manual, these emissions are "temporary" and "self-correcting once the project is completed." Nevertheless, NYSDOT recommends in that Manual that mitigation measures should be implemented to minimize emissions. Such measures will include proper maintenance of construction equipment, controlling unnecessary idling of equipment, and providing sufficient parking for construction workers.

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 on my inquiry of the person or persons directly responsible for gathering the 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	Title
Signature	Date / /

State Facility Certification

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

Responsible Official Peter Podurgiel (Competitive Power Ventures, Inc.)	Title Senior Vice President
Signature [signature]	Date 11 / 25 / 2008

Section II - Identification Information

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

Owner/Firm

Name	CPV Valley, LLC		
Street Address	8403 Colesville Road, Suite 915		
City Silver Spring	State Maryland	Country USA	Zip 20910
Owner Classification ☐ Federal ☒ Corporation/Partnership	☐ State ☐ Individual	☐ Municipal	Taxpayer ID 2 6 0 3 6 8 3 7 9

Facility ☐ Confidential

Name	CPV Valley, LLC	
Location Address	Route 6	
☒ City / ☐ Town / ☐ Village	Wawayanda, New York	Zip 10940

Project Description ☒ Continuation Sheet(s)

This application covers a new 630-megawatt (MW) combined cycle electric power generation facility to be owned and operated by CPV Valley, LLC. The facility is a major source pursuant to Non-Attainment NSR and Title V requirements.

Owner/Firm Contact Mailing Address

Name (Last, First, Middle Initial) Steven Remillard			Phone No. 781-817-8970
Affiliation CPV Valley, LLC	Title Director of Development		Fax No. 781-848-5804
Street Address 50 Braintree Hill Office Park, Suite 300			
City Braintree	State MA	Country USA	Zip 02184

Facility Contact Mailing Address

Name (Last, First, Middle Initial) Steven Remillard			Phone No. 781-817-8970
Affiliation CPV Valley, LLC	Title Director of Development		Fax No. 781-848-5804
Street Address 50 Braintree Hill Office Park, Suite 300			
City Braintree	State MA	Country USA	Zip 02184

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 on my inquiry of the person or persons directly responsible for gathering the 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	Title
Signature	Date ____/____/____

State Facility Certification

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

Responsible Official Peter Podurgiel (CPV Valley, LLC)	Title Senior Vice President
Signature	Date ____/____/____

Section II - Identification Information

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

Owner/Firm

Name	CPV Valley, LLC		
Street Address	8403 Colesville Road, Suite 915		
City Silver Spring	State Maryland	Country USA	Zip 20910
Owner Classification ❑ Federal ☒ Corporation/Partnership	❑ State ❑ Individual	❑ Municipal	Taxpayer ID 260368379

Facility

❑ Confidential

Name	CPV Valley, LLC	
Location Address	Route 6	
City / ☒ Town / ❑ Village	Wawayanda, New York	Zip10940

Project Description

☒ Continuation Sheet(s)

This application covers a new 630-megawatt (MW) combined cycle electric power generation facility to be owned and operated by CPV Valley, LLC. The facility is a major source pursuant to PSD, Non-Attainment NSR, and Title V requirements.

Owner/Firm Contact Mailing Address

Name (Last, First, Middle Initial) Steven Remillard			Phone No. 781-817-8970
Affiliation CPV Valley, LLC	Title Director of Development		Fax No. 781-848-5804
Street Address 50 Braintree Hill Office Park, Suite 300			
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Facility Contact Mailing Address

Name (Last, First, Middle Initial) Steven Remillard			Phone No. 781-817-8970
Affiliation CPV Valley, LLC	Title Director of Development		Fax No. 781-848-5804
Street Address 50 Braintree Hill Office Park, Suite 300			
City Braintree	State MA	Country USA	Zip 02184

DEC ID

Section II - Identification Information

Project Description (continuation)

The turbines/duct burners are also subject to Title IV (Acid Rain) Program, NOx SIP Call (NOx Budget) Program, Parts 237 and 238 (New York State NOx Budget and Acid Rain) requirements and Part 242 (CO2 Budget Trading Program).
Facility equipment subject to NOx RACT are the combustion turbines, duct burners, and auxiliary boiler.
The facility will be primarily fueled by natural gas with ultra-low sulfur diesel (ULSD) proposed as a back-up fuel.

Modeling analyses were conducted in accordance with a revised air quality modeling protocol that was submitted to NYSDEC and EPA in November 2008. A prior draft modeling protocol had been submitted to both agencies in September 2008 and was updated to account for subsequent Project Design changes and to address any agency review comments. The results of the modeling analyses indicate that impacts of the Project will be below established significant impact levels for CO, NO2, and SO2. Cumulative impact analyses for PM-10 indicate compliance with NAAQS, NYAQS, and Class II PSD increments for PM-10. Modeling also demonstrates that the sum of Project impacts of PM-2.5 and background levels will comply with NAAQS for PM-2.5. Modeling for non-criteria pollutants demonstrates that the Project will comply with guideline concentrations established by NYSDEC.

MACT and 112r (Accidental Release) requirements do not apply to the project.

The project is initially filing for Part 201 Major Source Pre-Construction Permit. The project will apply for a Title V permit within one-year of the commencement of operation.

A full description of the equipment is provided in the Facility Description Section of this application.

DEC ID

Section III - Facility Information

Classification					
❑ Hospital	❑ Residential	❑ Educational/Institutional	❑ Commercial	❑ Industrial	☒ Utility

Affected States (Title V Only)				
❑ Vermont	❑ Massachusetts	❑ Rhode Island	❑ Pennsylvania	Tribal Land:____________
❑ New Hampshire	❑ Connecticut	❑ New Jersey	❑ Ohio	Tribal Land:____________

SIC Codes												
4911												

Facility Description ☒ Continuation Sheet(s)
The CPV Valley Energy Center will consist of two dual fuel-fired F-class combustion turbine generators (CTGs), with a maximum
heat input of 2,234 mmBtu/hr, each when operating on natural gas at base load and -5 °F ambient temperature, two
500 mmBtu/hr supplementary natural gas-fired duct burners, two heat recovery steam generators

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

If one or 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 units 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 a 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	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	200	3						
6	NYCRR	200	5						
6	NYCRR	200	6						
6	NYCRR	200	7						

Facility State Only Requirements ☒ Continuation Sheet(s)

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	202	2						
6	NYCRR	207							
6	NYCRR	221							
6	NYCRR	293							

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Section III - Facility Information

Facility Description (continuation)

(HRSGs) and a single steam turbine generator (STG). Supporting ancillary equipment includes a 73.5 mmBtu/hr natural gas fired auxiliary boiler, a 15.43 mmBtu/hr ULSD emergency generator, two 5.0 mmBtu/hr dew point fuel gas heaters and a 2.27 mmBtu/hr ULSD fire water pump engine.

The proposed CTGs will be fueled by natural gas. Ultra-low sulfur diesel may be used as backup fuel for up to 720 hours per year per turbine. The duct burners will fire natural gas exclusively. The CTGs will utilize dry low-NOx (DLN) combustors for gas firing and water injection for control of nitrogen oxides (NOx) when firing ultra-low sulfur diesel. Selective catalytic reduction (SCRs) systems will be used to further control NOx emissions. Oxidation catalysts and efficient combustion controls will be used to control emissions of carbon monoxide (CO) as well as volatile organic compounds (VOCs). Emissions of SO2 and PM/PM-10 will be minimized through the use of pipeline natural gas and ULSD as backup, as well as efficient combustion controls. Upon leaving the SCRs, turbines gases will be directed to individual stacks at 275 feet above grade with a flue diameter of 19 feet. In addition, CTGs inlet air will be cooled using an evaporative cooler when ambient temperatures are high, to improve CTGs efficiency.

The Project will be designed to operate on a continuous basis for up to 8,760 hours/year, but may operate at partial loads when it is dispatched. Part load operation will be limited between 60% and 100% for natural gas and between 70% and 100% for ULSD.

The auxiliary boiler will employ low-NOx burners (LNB) and flue gas recirculation (FGR) to control emissions of NOx. The auxiliary boiler will operate as needed to keep the HRSG warm during periods of turbine shutdown and to provide sealing steam to the steam turbine in the case of warm and hot startups. Total boiler hours for the facility will be limited to 2,000 hours per year.

The dew point fuel gas heaters will employ a forced draft burners to reduce NOx emissions. The units will heat the natural gas to optimum firing temperature. The dew point heaters are proposed to operate up to 8,760 hours per year.

The emergency diesel fire pump will provide provide on-site fire fighting capability independent of the utility grid. The emergency diesel generator will be operated only for testing and to maintain operational readiness or if needed for emergency operation. Each emergency engine will be allowed to operate for up to 500 hours per year.

Only the facility’s combustion turbines, duct burners and auxiliary boiler are subject to NYSDEC NOx RACT provisions.

The dew point heater, the emergency diesel generator and the emergency diesel fire pump are exempt activities pursuant to Part 201-3.2.

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Section III - Facility Information

Facility Applicable Federal Requirements (continuation)

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph h	Sub Paragraph	Clause	Sub Clause
6	NYCRR	201	1	2					
6	NYCRR	201	1	4					
6	NYCRR	201	1	5					
6	NYCRR	201	1	6					
6	NYCRR	201	1	7					
6	NYCRR	201	1	8					
6	NYCRR	201	1	10	a				
6	NYCRR	201	1	10	b				
6	NYCRR	201	2						
6	NYCRR	201	3	2	a				
6	NYCRR	201	3	3	a				
6	NYCRR	201	6	1	b				
6	NYCRR	201	6	1	b	3			
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	211	2						
6	NYCRR	215							
6	NYCRR	225	1	2	c				
6	NYCRR	225	1	2	d				
6	NYCRR	225	1	6	a				
6	NYCRR	225	1	6	b				
6	NYCRR	225	1	8	a				
6	NYCRR	225	1	8	c				
6	NYCRR	225	1	8	d				
6	NYCRR	227	2	1					
6	NYCRR	231	2	1					
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		5		a			
6	NYCRR	621		13		a			
6	NYCRR	621		14					
40	CFR	82	F						

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Section III - Facility Information (continued)

Facility Compliance Certification ☒ Continuation Sheet(s)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	211	3						

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

Monitoring Information

❑ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ❑ Record Keeping/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 the 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	Limit Units Code	Limit Units Description
20	0	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	As Required	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		F	
NY075 - 00 - 0	Particulate Matter		F	
7446 - 09 - 5	Sulfur Dioxide		E	
NY210 - 00 - 0	Oxides of Nitrogen		G	
630 - 08 - 0	Carbon Monoxide		H	
NY998 - 00 - 0	VOC		F	
NY100 - 00 - 0	HAP		C	
07664 93 9	Sulfuric Acid Mist		C	
106 - 99 - 0	1,3 Butadiene		Y	
71 - 55 - 6	1,1,1-Trichloroethane		Y	
56 - 49 - 5	3-Methylchloranthrene		Y	
57 - 97 - 6	7,12-Dimethylbenz(a)anthracene		Y	
83 - 32 - 9	Acenaphthene		Y	
208 - 96 - 8	Acenaphthylene		Y	

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Section III - Facility Information

Facility Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	225	1	2					

		CAS No.	Contaminant Name
☐ Applicable Federal Requirement ☒ State Only Requirement	❑ Capping	7704 - 34 - 9	Sulfur

Monitoring Information

❑ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ❑ Record Keeping/Maintenance Procedures

Description

Maintaining compliance with the proposed BACT fuel sulfur limit of 0.0015% by weight ensures compliance with the fuel sulfur limit listed in 6 NYCRR 225-1.2.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		57	Percent by Weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

		CAS No.	Contaminant Name
☒ Applicable Federal Requirement ❑ State Only Requirement	❑ Capping	7664 - 09 - 5	Sulfur Dioxide

Monitoring Information

❑ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ❑ Record Keeping/Maintenance Procedures

Description

Facility SO2 emissions are subject to BACT. The facility is proposing to limit the sulfur content of combustion fuel oil to 0.0015% sulfur by weight

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	percent by weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

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Section III - Facility Information

Facility Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement	❑ Capping	CAS No.	Contaminant Name
		NY075 - 00 - 5	Particulates

Monitoring Information

❑ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ❑ Record Keeping/Maintenance Procedures

Description

Facility PM10 emissions are subject to BACT. The facility is proposing to limit the sulfur content of combustion fuel oil to 0.0015% sulfur by weight

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	Percent by Weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement	❑ Capping	CAS No.	Contaminant Name
		7664 - 93 - 9	Sulfuric Acid Mist

Monitoring Information

❑ Ambient Air Monitoring ☒ Work Practice Involving Specific Operations ❑ Record Keeping/Maintenance Procedures

Description

Facility sulfuric acid mist emissions are subject to BACT. The facility is proposing to limit the sulfur content of combustion fuel oil to 0.0015% sulfur by weight

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	Percent by Weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

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Section III - Facility Information

Facility Compliance Certification (continuation)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	201	7	2					

		CAS No.	Contaminant Name
☒ Applicable Federal Requirement ❑ State Only Requirement	☒ Capping	NY075 - 00 - 5	PM/PM-10/PM-2.5

Monitoring Information

❑ Ambient Air Monitoring ❑ Work Practice Involving Specific Operations ☒ Record Keeping/Maintenance Procedures

Description

Potential emissions of PM/PM-10/PM-2.5 will be limited to 95 tpy by an enforceable permit limit. Compliance shall be maintained by monthly calculation of rolling 12-month total PM emissions.

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Section III - Facility Information

Facility Emissions Summary (continuation)

CAS No.	Contaminant Name	PTE (lbs/yr)	PTE Range Code	Actual (lbs/yr)
75 - 07 - 0	Acetaldehyde		Y	
107 - 02 - 8	Acrolein		Y	
120 - 12 - 7	Anthracene		Y	
07440 - 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	
07740 - 41 - 7	Beryllium		Y	
07740 - 43 - 9	Cadmium		Y	
07740 - 47 - 3	Chromium		Y	
218 - 01 - 9	Chrysene		Y	
07740 - 48 - 4	Cobalt		Y	
53 - 70 - 3	Dibenzo(a,h)anthracene		Y	
106 - 46 - 7	Dichlorobenzene		Y	
100 - 41 - 4	Ethylbenzene		Y	
206 - 44 - 0	Fluoranthene		Y	
7782 - 96 - 5	Fluorene		Y	
50 - 00 - 0	Formaldehyde		Y	
110 - 54 - 3	Hexane		Y	
193 - 39 - 5	Indeno(1,2,3-cd)pyrene		Y	
07439 - 92 - 1	Lead		Y	
07439 - 96 - 5	Manganese		Y	
07439 - 97 - 6	Mercury		Y	
91 - 20 - 3	Naphthalene		Y	
07740 - 02 - 0	Nickel		Y	
130498 - 29 - 2	PAH		Y	
85 - 01 - 8	Phenanthrene		Y	
0	POM		Y	
75 - 56 - 9	Propylene Oxide		Y	
129 - 00 - 0	Pyrene		Y	
07782 - 49 - 2	Selenium		Y	
108 - 88 - 3	Toluene		Y	
133 - 02 - 7	Xylenes		Y	

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Section IV - Emission Unit Information

Emission Unit Description

☒ Continuation Sheet(s)

EMISSION UNIT: U - 0 0 0 0 1

One F-class combustion turbine rated at 1,998 mmBtu/hr at 51°F (2,234 mmBtu/hr at -5°F) on natural gas and 2,145 mmBtu/hr at -5°F on fuel oil (<0.0015% sulfur). The turbine is equipped with dry low-NOx combustors, steam injection, SCR and oxidation catalyst emission controls. This emission unit also contains a natural gas-fired duct burner rated at a maximum capacity of 500 mmBtu/hr.

Building

❑ Continuation Sheet(s)

Building	Building Name	Length (ft)	Width (ft)	Orientation
GEN01	Generation Building	304	263	North
ACC01	Air Cooled Condenser	303	267	North
HRSG01	Heat Recovery Steam Generator	220	202	North

Emission Point

☐ Continuation Sheet(s)

EMISSION PT.: E P 0 0 1 — U-00001 (CT/HRSG)

Ground Elev. (ft)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
464	275	162	228	195		
Exit Velocity (FPS)	**Exit Flow (ACFM)**	**NYTM (E) (KM)**	**NYTM (N) (KM)**	**Building**	**Distance to Property Line (ft)**	**Date of Removal**
72.4	1,231,680	546.98048	4,584.69287		178	

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.
CT001	C	01/2010	06/2012				Class-F Turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
~~2,234~~	~~25~~	~~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.
~~DB001~~	~~C~~	~~01/2010~~	~~06/2012~~				~~Duct Burner~~

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
~~500~~	~~25~~	~~mmBtu/hr~~				

DEC ID

Section IV - Emission Unit Information

Emission Unit Description

☒ Continuation Sheet(s)

EMISSION UNIT U - 0 0 0 0 2

One Class-F combustion turbine rated at 1,998 mmBtu/hr at 51°F (2,234 mmBtu/hr at -5°F) on natural gas and 2,145 mmBtu/hr at -5°F on fuel oil (<0.0015% sulfur). The turbine is equipped with dry low-NOx combustors, steam injection, SCR and emission controls. This emission unit also contains a natural gas-fired duct burner rated at a maximum capacity of 500 mmBtu/hr.

Building

❑ Continuation Sheet(s)

Building	Building Name	Length (ft)	Width (ft)	Orientation
GEN02	Generation Building	304	263	South
ACC02	Air Cooled Condenser	303	267	South
HRSG02	Heat Recovery Steam Generator	220	202	South

Emission Point

☐ Continuation Sheet(s)

EMISSION PT. E P 0 0 2 **U-00002 (CT/HRSG)**

Ground Elev. (ft)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
464	275	162	228	195		

Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal
72.4	1,231,680	546.99053	4,584.65455		305	

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.
CT002	C	01/2010	06/2012				Class-F turbine

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
2,234	25	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.
DB002	C	01/2010	01/2012				Duct Burner

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
500	25	mmBtu/hr				

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Section IV - Emission Unit Information

Emission Unit Description

☒ Continuation Sheet(s)

EMISSION UNIT	U - 0 0 0 0 3

One 73.5 mmBtu/hr auxiliary boiler that will fire natural gas exclusively. The boiler hours will be limited to 2000 hours per year.
The boiler will operate primarily to assist with startups and shutdowns of the turbine.

Building

❑ Continuation Sheet(s)

Building	Building Name	Length (ft)	Width (ft)	Orientation
GEN01	Generation Building	304	263	North

Emission Point

☐ Continuation Sheet(s)

EMISSION PT.	E P 0 0 2	U-00003 (Aux Boiler)				
Ground Elev. (ft)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section Length (in)	Cross Section Width (in)
464	275	162	228	195		
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal
72.4	1,231,680	546.99053	4,584.65455		305	

Emission Source/Control

☒ Continuation Sheet(s)

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.
Aux Boil.	C	01/2010	06/2012				TBD

Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
73.5	25	mmBtu/hr				

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Section IV - Emission Unit Information

EMISSION UNIT: U - 0 0 0 0 1

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	01/2010	06/2012		103	Dry Low-NO_x Combustor	TBD
STI01	K	01/2010	06/2012		028	Steam or Water Injection	TBD
SCR01	K	01/2010	06/2012		033	SCR	TBD
OXY01	K	01/2010	01/2012		110	Oxidation Catalyst	TBD

Emission Source ID	Design Capacity	Design Capacity Units Code	Design Capacity Units Description	Waste Feed Code	Waste Feed Description	Waste Type Code	Waste Type Description
DLN01							
STI01							
SCR01							
OXY01							

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Section IV - Emission Unit Information

EMISSION UNIT	Emission Source/Control (continuation)
U-00002	

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.
DLN02	K	01/2010	06/2012		103	Dry Low-NO_x Combustor	TBD
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.**
STI02	K	01/2010	06/2012		028	Steam or Water Injection	TBD
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	01/2010	06/2012		033	SCR	TBD
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	01/2010	01/2012		110	Oxidation Catalyst	TBD
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.**
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.**
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.**
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: U - 0 0 0 0 3

Emission Source/Control (continuation)

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.
AUX01	C	01/2010	06/2012				TBD
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / Description**
73.5	25	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.**
LNB01	K	01/2010	06/2012		102	Low-NOx Burner	TBD
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / 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.**
FGR01	K	01/2010	06/2012		026	Flue Gas Recirculation	TBD
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / 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.**
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / 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.**
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / 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.**
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / 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.**
Design Capacity	**Design Capacity Units Code**	**Design Capacity Units Description**			**Waste Feed Code**	**Waste Feed Description**	**Waste Type Code / Description**

DEC ID

Section IV - Emission Unit Information (continued)

Process Information

☒ Continuation Sheet(s)

EMISSION UNIT: U-00001 — PROCESS: P01

Description

Process P01 represents natural gas firing in the Class-F combustion turbine, which is rated at 2,234 mmBtu/hr at -5°F (maximum heat input scenario). Dry low-NOx combustion technology, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate (2,234 mmBtu/hr at -5°F) and the quantity per year throughput represents the turbine at the firing rate at the annual average ambient temperature of 51 °F (1,998 mmBtu/hr). Natural gas Higher Heating Value (HHV) is assumed to be 1,048 Btu/cubic foot.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-002-01	2.13	16,700	0115	million cubic feet gas

	Operating Schedule		Building	Floor/Location
❑ Confidential ☒ Operating at Maximum Capacity ❑ Activity with Insignificant Emissions	Hrs/Day	Days/Yr		
	24	365		

Emission Source/Control Identifier(s)							
CT001	DLN01	SCR01	OXY01				

EMISSION UNIT: U-00001 — PROCESS: P02

Description

Process P02 represents combined natural gas firing in the Class-F combustion turbine, which is rated at 2,234 mmBtu/hr at -5°F (maximum heat input scenario) and natural gas firing in the duct burner, which is rated at 500 mmBtu/hr. Dry low-NOx combustion technology, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate of the turbine (2,234 mmBtu/hr at -5°F) plus the duct burner at rated capacity (500 mmBtu/hr) and the quantity per year throughput represents 8,760 hours of natural gas firing in the turbine at the annual average ambient temperature of 51 °F (1,998 mmBtu/hr) plus 2,628 hours of natural gas firing in the duct burner at rated capacity (500 mmBtu/hr). Natural gas Higher Heating Value (HHV) is assumed to be 1,048 Btu/cubic foot.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-002-01	2.61	17,954	0115	million cubic feet gas

	Operating Schedule		Building	Floor/Location
❑ Confidential ☒ Operating at Maximum Capacity ❑ Activity with Insignificant Emissions	Hrs/Day	Days/Yr		
	24	365		

Emission Source/Control Identifier(s)							
CT001	DB001	DLN01	SCR01	OXY01			

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Section IV - Emission Unit Information

Process Information (continuation)

❑ Continuation Sheet(s)

EMISSION UNIT: U-00001 | PROCESS: P03

Description

Process P03 represents fuel oil firing in the Class-F combustion turbine, which is rated at 2,145 mmBtu/hr at -5ºF (maximum heat input scenario). Dry low-NOx combustion technology, steam or water injection, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate (2,145 mmBtu/hr at -5ºF) and the quantity per year throughput represents 720 hours of fuel oil firing at the firing rate at -5ºF ambient temperature. Fuel oil Higher Heating Value (HHV) is assumed to be 139,728 Btu/gallon.

Source Classification Code (SCC)	Total Thruput Quantity/Hr	Total Thruput Quantity/Yr	Thruput Quantity Units Code	Thruput Quantity Units Description
2-01-001-01	15.351	11,053	0607	1,000 gallons burned

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

Operating Schedule Hrs/Day	Operating Schedule Days/Yr	Building	Floor/Location
24	30		

Emission Source/Control Identifier(s)

CT001	DLN01	STI01	SCR01	OXY01			

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Section IV - Emission Unit Information (continued)

Process Information

☒ Continuation Sheet(s)

EMISSION UNIT	U - 0 0 0 0 2	PROCESS	P 0 1

Description

Process P01 represents natural gas firing in the Class-F combustion turbine, which is rated at 2,234 mmBtu/hr at -5°F (maximum heat input scenario). Dry low-NOx combustion technology, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate (2,234 mmBtu/hr at -5°F) and the quantity per year throughput represents the turbine at the firing rate at the annual average ambient temperature of 51 °F (1,998 mmBtu/hr). Natural gas Higher Heating Value (HHV) is assumed to be 1,048 Btu/cubic foot.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-002-01	2.13	16,700	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		

Emission Source/Control Identifier(s)

CT001	DLN01	SCR01	OXY01				

EMISSION UNIT	U - 0 0 0 0 2	PROCESS	P 0 2

Description

Process P02 represents combined natural gas firing in the Class-F combustion turbine, which is rated at 2,234 mmBtu/hr at -5°F (maximum heat input scenario) and natural gas firing in the duct burner, which is rated at 500 mmBtu/hr. Dry low-NOx combustion technology, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate of the turbine (2,234 mmBtu/hr at -5°F) plus the duct burner at rated capacity (500 mmBtu/hr) and the quantity per year throughput represents 8,760 hours of natural gas firing in the turbine at the annual average ambient temperature of 51 °F (1,998 mmBtu/hr) plus 2,628 hours of natural gas firing in the duct burner at rated capacity (500 mmBtu/hr). Natural gas Higher Heating Value (HHV) is assumed to be 1,048 Btu/cubic foot.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-002-01	2.61	17,954	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		

Emission Source/Control Identifier(s)

CT001	DB001	DLN01	SCR01	OXY01			

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Section IV - Emission Unit Information

Process Information (continuation)

❑ Continuation Sheet(s)

EMISSION UNIT	U-00002	PROCESS	P03

Description

Process P03 represents fuel oil firing in the Class-F combustion turbine, which is rated at 2,145 mmBtu/hr at -5ºF (maximum heat input scenario). Dry low-NOx combustion technology, steam or water injection, selective catalytic reduction (SCR) and oxidation catalyst will be used to minimize emissions of NOx, CO, and VOC. The quantity per hour throughput listed below represents the maximum firing rate (2,145 mmBtu/hr at -5ºF) and the quantity per year throughput represents 720 hours of fuel oil firing at the firing rate at -5ºF ambient temperature. Fuel oil Higher Heating Value (HHV) is assumed to be 139,728 Btu/gallon.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
2-01-001-01	15.351	11,053	0607	1,000 gallons burned

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

Operating Schedule		Building	Floor/Location
Hrs/Day	Days/Yr		
24	30		

Emission Source/Control Identifier(s)

CT001	DLN01	STI01	SCR01	OXY01			

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Section IV - Emission Unit Information

Process Information (continuation)

❑ Continuation Sheet(s)

EMISSION UNIT	U-00003	PROCESS	P01

Description

Process P01 represents natural gas firing in the auxiliary boiler, which is rated at 73.5 mmBtu/hr.
Total natural gas usage will not exceed 2,000 full load boiler hours per year. Natural gas Higher Heating Value (HHV) is assumed to be 1,048 Btu/cubic foot.

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description
1-02-006-02	0.07	140.27	0115	million cubic feet gas

	Operating Schedule		Building	Floor/Location
❑ Confidential ☒ Operating at Maximum Capacity ❑ Activity with Insignificant Emissions	Hrs/Day	Days/Yr		
	24	83		

Emission Source/Control Identifier(s)							
AUX01	LNB01	FGR01					

EMISSION UNIT		PROCESS	

Description

Source Classification Code (SCC)	Total Thruput		Thruput Quantity Units	
	Quantity/Hr	Quantity/Yr	Code	Description

	Operating Schedule		Building	Floor/Location
❑ Confidential ❑ Operating at Maximum Capacity ❑ Activity with Insignificant Emissions	Hrs/Day	Days/Yr		

Emission Source/Control Identifier(s)							

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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	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
U - 00001				40	CFR	60	A	7					
U - 00001				40	CFR	60	A	8					
U - 00001				40	CFR	60	A	11					
U - 00001				40	CFR	60	A	12					
U - 00001				40	CFR	60	A	13					

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements ☒ Continuation Sheet(s)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
U - 00001				6	NYCRR	237	1	4	a				
U - 00001				6	NYCRR	237	1	6					
U - 00001				6	NYCRR	237	1	7					
U - 00001				6	NYCRR	237	2						
U - 00001				6	NYCRR	237	3						

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
U - 00001		P01, 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

2.0 ppmvd (corrected to 15% O2) NOx emission limit for the combustion turbine (with and without the duct burner) based upon the Higher Heating Value (HHV) of the fuel. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will use CEMS to monitor NOx stack emissions. The emission limits represents LAER.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements								☒ Continuation Sheet(s)	
				Title	Type	Part	Sub Part	Section	Sub Division	Parag	Sub Parag.	Clause	Sub Clause
U - 00002				40	CFR	60	A	7					
U - 00002				40	CFR	60	A	8					
U - 00002				40	CFR	60	A	11					
U - 00002				40	CFR	60	A	12					
U - 00002				40	CFR	60	A	13					

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements								☒ Continuation Sheet(s)	
				Title	Type	Part	Sub Part	Section	Sub Division	Parag	Sub Parag.	Clause	Sub Clause
U - 00002				6	NYCRR	237	1	4	a				
U - 00002				6	NYCRR	237	1	6					
U - 00002				6	NYCRR	237	1	7					
U - 00002				6	NYCRR	237	2						
U - 00002				6	NYCRR	237	3						

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
U - 00002		P01, 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

2.0 ppmvd (corrected to 15% O2) NOx emission limit for the combustion turbine (with and without the duct burner) based upon the Higher Heating Value (HHV) of the fuel. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will use CEMS to monitor NOx stack emissions. The emission limits represents LAER.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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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Section IV - Emission Unit Information

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements (continuation)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub. Clause
U - 00001				40	CFR	60	A	13					
U - 00001				40	CFR	60	A	19					
U - 00001				40	CFR	60	KKKK	4320	a and b				
U - 00001				40	CFR	60	KKKK	4325					
U - 00001				40	CFR	60	KKKK	4330	a	1 or 2			
U - 00001				40	CFR	60	KKKK	4333	a and b	1 or 2			
U - 00001				40	CFR	60	KKKK	4335	b				
U - 00001				40	CFR	60	KKKK	4345	a, b, c,d & e				
U - 00001				40	CFR	60	KKKK	4350					
U - 00001				40	CFR	60	KKKK	4365	a				
U - 00001				40	CFR	60	KKKK	4375	a				
U - 00001				40	CFR	60	KKKK	4380	b	1, 2 & 3			
U - 00001				40	CFR	60	KKKK	4395					
U - 00001				40	CFR	60	KKKK	4400					
U - 00001				40	CFR	60	KKKK	4405	a, b, c and d				
U - 00001				40	CFR	72	A	6	a	3			
U - 00001				40	CFR	72	A	9					
U - 00001				40	CFR	75	B	10					
U - 00001				40	CFR	75	B	11	d				
U - 00001				40	CFR	75	B	11	d	2			
U - 00001				40	CFR	75	B	12	c				
U - 00001				40	CFR	75	B	12	c				
U - 00001				40	CFR	75	B	13	b				
U - 00001				40	CFR	75	C						
U - 00001				40	CFR	75	D						
U - 00001				40	CFR	75	F	53	a				
U - 00001				40	CFR	75	F	53	b				
U - 00001				40	CFR	75	F	53	e				
U - 00001				40	CFR	75	F	53	f				
U - 00001				40	CFR	75	F	54					
U - 00001				40	CFR	75	F	58	b	2			
U - 00001				40	CFR	75	F	58	b	3			
U - 00001				40	CFR	75	F	58	c				
U - 00001				40	CFR	75	F	59					
U - 00001				40	CFR	75	G						
U - 00001				6	NYCRR	227	1	2	a	1			
U - 00001				6	NYCRR	227	1	3					
U - 00001				6	NYCRR	227	1	4	d				
U - 00001				6	NYCRR	227	2	4	e	2			
U - 00001				6	NYCRR	227	2	6					

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Section IV - Emission Unit Information

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements (continuation)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
U - 00001				6	NYCRR	237	4	1					
U - 00001				6	NYCRR	237	5	3	a				
U - 00001				6	NYCRR	237	6						
U - 00001				6	NYCRR	237	7						
U - 00001				6	NYCRR	237	8						
U - 00001				6	NYCRR	238	1	4					
U - 00001				6	NYCRR	238	1	6					
U - 00001				6	NYCRR	238	1	7					
U - 00001				6	NYCRR	238	2						
U - 00001				6	NYCRR	238	3						
U - 00001				6	NYCRR	238	4	1					
U - 00001				6	NYCRR	238	5	3	a				
U - 00001				6	NYCRR	238	6						
U - 00001				6	NYCRR	238	7						
U - 00001				6	NYCRR	238	8						
U - 00001				6	NYCRR	242	1	6					
U - 00001				6	NYCRR	242	1	7					
U - 00001				6	NYCRR	242	2						
U - 00001				6	NYCRR	242	3						
U - 00001				6	NYCRR	242	4						
U - 00001				6	NYCRR	242	5						
U - 00001				6	NYCRR	242	6						
U - 00001				6	NYCRR	242	7						
U - 00001				6	NYCRR	242	8						
U - 00001				6	NYCRR	242	10						
U - 00001				6	NYCRR	204	1	6					
U - 00001				6	NYCRR	204	1	7					
U - 00001				6	NYCRR	204	2						
U - 00001				6	NYCRR	204	3						
U - 00001				6	NYCRR	204	4						
U - 00001				6	NYCRR	204	5						
U - 00001				6	NYCRR	204	6						
U - 00001				6	NYCRR	204	7						
U - 00001				6	NYCRR	204	8						
U - 00001				6	NYCRR	204	9						
-													
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Section IV - Emission Unit Information

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements (continuation)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub. Clause
U - 00002				40	CFR	60	A	13					
U - 00002				40	CFR	60	A	19					
U - 00002				40	CFR	60	KKKK	4320	a and b				
U - 00002				40	CFR	60	KKKK	4325					
U - 00002				40	CFR	60	KKKK	4330	a	1 or 2			
U - 00002				40	CFR	60	KKKK	4333	a and b	1 or 2			
U - 00002				40	CFR	60	KKKK	4335	b				
U - 00002				40	CFR	60	KKKK	4345	a, b, c,d & e				
U - 00002				40	CFR	60	KKKK	4350					
U - 00002				40	CFR	60	KKKK	4365	a				
U - 00002				40	CFR	60	KKKK	4375	a				
U - 00002				40	CFR	60	KKKK	4380	b	1, 2 & 3			
U - 00002				40	CFR	60	KKKK	4395					
U - 00002				40	CFR	60	KKKK	4400					
U - 00002				40	CFR	60	KKKK	4405	a, b, c and d				
U - 00002				40	CFR	72	A	6	a	3			
U - 00002				40	CFR	72	A	9					
U - 00002				40	CFR	75	B	10					
U - 00002				40	CFR	75	B	11	d				
U - 00002				40	CFR	75	B	11	d	2			
U - 00002				40	CFR	75	B	12	c				
U - 00002				40	CFR	75	B	12	c				
U - 00002				40	CFR	75	B	13	b				
U - 00002				40	CFR	75	C						
U - 00002				40	CFR	75	D						
U - 00002				40	CFR	75	F	53	a				
U - 00002				40	CFR	75	F	53	b				
U - 00002				40	CFR	75	F	53	e				
U - 00002				40	CFR	75	F	53	f				
U - 00002				40	CFR	75	F	54					
U - 00002				40	CFR	75	F	58	b	2			
U - 00002				40	CFR	75	F	58	b	3			
U - 00002				40	CFR	75	F	58	c				
U - 00002				40	CFR	75	F	59					
U - 00002				40	CFR	75	G						
U - 00002				6	NYCRR	227	1	2	a	1			
U - 00002				6	NYCRR	227	1	3					
U - 00002				6	NYCRR	227	1	4	d				
U - 00002				6	NYCRR	227	2	4	e	2			
U - 00002				6	NYCRR	227	2	6					

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Section IV - Emission Unit Information

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements (continuation)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
U - 00002				6	NYCRR	237	4	1					
U - 00002				6	NYCRR	237	5	3	a				
U - 00002				6	NYCRR	237	6						
U - 00002				6	NYCRR	237	7						
U - 00002				6	NYCRR	237	8						
U - 00002				6	NYCRR	238	1	4					
U - 00002				6	NYCRR	238	1	6					
U - 00002				6	NYCRR	238	1	7					
U - 00002				6	NYCRR	238	2						
U - 00002				6	NYCRR	238	3						
U - 00002				6	NYCRR	238	4	1					
U - 00002				6	NYCRR	238	5	3	a				
U - 00002				6	NYCRR	238	6						
U - 00002				6	NYCRR	238	7						
U - 00002				6	NYCRR	238	8						
U - 00002				6	NYCRR	242	1	6					
U - 00002				6	NYCRR	242	1	7					
U - 00002				6	NYCRR	242	2						
U - 00002				6	NYCRR	242	3						
U - 00002				6	NYCRR	242	4						
U - 00002				6	NYCRR	242	5						
U - 00002				6	NYCRR	242	6						
U - 00002				6	NYCRR	242	7						
U - 00002				6	NYCRR	242	8						
U - 00002				6	NYCRR	242	10						
U - 00002				6	NYCRR	204	1	6					
U - 00002				6	NYCRR	204	1	7					
U - 00002				6	NYCRR	204	2						
U - 00002				6	NYCRR	204	3						
U - 00002				6	NYCRR	204	4						
U - 00002				6	NYCRR	204	5						
U - 00002				6	NYCRR	204	6						
U - 00002				6	NYCRR	204	7						
U - 00002				6	NYCRR	204	8						
U - 00002				6	NYCRR	204	9						
-													
-													

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Section IV - Emission Unit Information

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements (continuation)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub. Clause
U - 00003		P02		40	CFR	60	Dc	42c	d				
U - 00003		P02		40	CFR	60	Dc	43c	a	2			
U - 00003		P02		40	CFR	60	Dc	43c	c				
U - 00003				6	NYCRR	227	2	4	d				
U - 00003				6	NYCRR	227	2	6					

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00001		P03		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

6.0 ppmvd (corrected to 15% O2) NOx emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will use CEMS to monitor NOx stack emissions. The emission limit represents LAER.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
6.0		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00002		P03		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

6.0 ppmvd (corrected to 15% O2) NOx emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will use CEMS to monitor NOx stack emissions. The emission limit represents LAER.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
6.0		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	2	4	e	2	i		
⊠ Applicable Federal Requirement		❑ State Only Requirement				❑ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00001		P01, 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

Maintaining compliance with the proposed combustion turbine/duct burner LAER emission limits by using the NOx CEMS
ensures compliance with the NOx emission limits listed in NYCRR 227.2-4(e)(2)(i) will be determined using CEMS since the
LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
42		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	2	4	e	2	ii		
⊠ Applicable Federal Requirement		❑ State Only Requirement				❑ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00001		P03		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

Maintaining compliance with the proposed combustion turbine/duct burner LAER emission limits by using the NOx CEMS
ensures compliance with the NOx emission limits listed in NYCRR 227.2-4(e)(2)(ii) will be determined using CEMS since the
LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
65		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

DEC ID

Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	2	4	e	2	i		

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P01, 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

Maintaining compliance with the proposed combustion turbine/duct burner LAER emission limits by using the NOx CEMS
ensures compliance with the NOx emission limits listed in NYCRR 227.2-4(e)(2)(i) will be determined using CEMS since the
LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
42		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	2	4	e	2	ii		

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		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

Maintaining compliance with the proposed combustion turbine/duct burner LAER emission limits by using the NOx CEMS
ensures compliance with the NOx emission limits listed in NYCRR 227.2-4(e)(2)(ii) will be determined using CEMS since the
LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
65		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

DEC ID

Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	60	KKKK	4345	a to e				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P01, P03		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

Maintaining compliance with the proposed combustion turbine LAER emission limits by using the NOx CEMS ensures compliance with the NOx emission limits listed in 40 CFR 60.332a since the LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
75		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	60	KKKK	4345	a to e				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P01, P03		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

Maintaining compliance with the proposed combustion turbine LAER emission limits by using the NOx CEMS ensures compliance with the NOx emission limits listed in 40 CFR 60.332a since the LAER emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
75		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00003		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

0.0450 lb/mmBtu NOx emission limit from the auxiliary boiler based upon Higher Heating Value (HHV) of the natural gas.

This emission limit applies at all loads except during startup and shutdown. The facility will use vendor emission guarantees and/or stack testing to ensure compliance with the LAER emission limit, as required.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 7E

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.045		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

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

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

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
			As Required		

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00001		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

0.7 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine based upon Higher Heating Value (HHV)
of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. Stack testing will
be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.7		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	14	As Required	10	Upon Request

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
U - 00001		P02		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

1.8 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine (with duct burner) based upon Higher Heating Value
Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching.
Stack testing will be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.5		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	14	As Required	10	Upon Request

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00002		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

0.7 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine based upon Higher Heating Value (HHV)
of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. Stack testing will
be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.7		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	14	As Required	10	Upon Request

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
U - 00002		P02		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

1.8 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine (with duct burner) based upon Higher Heating Value
Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching.
Stack testing will be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.5		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	14	As Required	10	Upon Request

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)									
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
U - 00001		P03		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

0.7 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. Stack testing will be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.7		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	14	As Required	10	Upon Request

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00002		P03		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

0.7 ppmvd (corrected to 15% O2) VOC emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. Stack testing will be used to demonstrate compliance with the LAER emission limit.

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.7		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	14	As Required	10	Upon Request

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

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
U - 00003		P01		NY998 - 08 - 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

0.0038 lb/mmBtu VOC emission limit from the auxiliary boiler based upon Higher Heating Value (HHV) of the natural gas.

This emission limit applies at all loads except during startup and shutdown. The facility will use vendor emission guarantees and/or stack testing to ensure compliance with the LAER emission limit, as required

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

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0038		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

Rule Citation

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

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

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

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

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

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P01,P02		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine without duct burner and 3.6 ppmvd with duct burner based upon the Higher Heating Value (HHV) of the fuel. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
3.6		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P03		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine based upon the Higher Heating Value (HHV) of the fuel.

The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P01,P02		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine without duct burner and 3.6 ppmvd with duct burner based upon
the Higher Heating Value (HHV) of the fuel This emission limit applies at all loads except during startup, shutdown and
fuel switching. The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
3.6		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine based upon the Higher Heating Value (HHV)
of the fuel.
The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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

DEC ID

Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P03		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine based upon the Higher Heating Value (HHV) of the fuel.

The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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

DEC ID

Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		630 - 08 - 0	Carbon Monoxide

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

2.0 ppmvd (corrected to 15% O2) CO emission limit for the combustion turbine based upon the Higher Heating Value (HHV) of the fuel.

The facility will use CEMS to monitor CO stack emissions. The emission limit represents BACT.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
2.0		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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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00003		P01		630 - 08 - 0	Carbon Monoxide

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

0.0721 lb/mmBtu CO emission limit from the auxiliary boiler based upon Higher Heating Value (HHV) of the natural gas.

This emission limit applies at all loads except during startup and shutdown. The facility will use vendor emission guarantees and/or stack testing to ensure compliance with the BACT emission limit, as required.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			40 CFR Part 60, Appendix A, Method 10

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0721		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

Rule Citation

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

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

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

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

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

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P01		NY075 - 00 - 0	Particulates

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

0.0073 lb/mmBtu PM emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the natural gas.

The emission limits applies at all load except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0073		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P02		NY075 - 00 - 0	Particulates

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

0.0062 lb/mmBtu PM emission limit from the combustion turbine (with duct burner) based upon Higher Heating Value (HHV) of the natural gas. The emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0062		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

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Section IV - Emission Unit Information

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P01		NY075 - 00 - 0	Particulates

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

0.0073 lb/mmBtu PM emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the natural gas.

The emission limits applies at all load except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0073		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P02		NY075 - 00 - 0	Particulates

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

0.0062 lb/mmBtu PM emission limit from the combustion turbine (with duct burner) based upon Higher Heating Value (HHV) of the natural gas. The emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0062		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

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Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ☐ State Only Requirement ☐ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P03		NY075 - 00 - 0	Particulates

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

0.0368 lb/mmBtu PM emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. The emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0368		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

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Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		NY075 - 00 - 0	Particulates

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

0.0368 lb/mmBtu PM emission limit from the combustion turbine based upon Higher Heating Value (HHV) of the fuel oil. The emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by stack testing.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0368		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

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Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	1	2	a	1			

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P03		NY075 - 00 - 0	Particulates

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

Maintaining compliance with the proposed combustion turbine BACT PM emission limits when firing fuel oil by stack testing ensures compliance with the PM emission limits listed in 6 NYCRR 227-1.2(a)(1) since the BACT emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.10		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	60	42	a	a	1			

☒ Applicable Federal Requirement ☐ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P02		NY075 - 00 - 0	Particulates

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

Maintaining compliance with the proposed duct burner BACT PM emission limits by stack testing ensures compliance with the PM emission limit listed in 40 CFR 60.42a(a)(1).

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.03		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

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Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
6	NYCRR	227	1	2	a	1			

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		NY075 - 00 - 0	Particulates

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

Maintaining compliance with the proposed combustion turbine BACT PM emission limits when firing fuel oil by stack testing ensures compliance with the PM emission limits listed in 6 NYCRR 227-1.2(a)(1) since the BACT emission limits are more restrictive.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.10		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

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	60	42	a	a	1			

☒ Applicable Federal Requirement ☐ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P02		NY075 - 00 - 0	Particulates

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

Maintaining compliance with the proposed duct burner BACT PM emission limits by stack testing ensures compliance with the PM emission limit listed in 40 CFR 60.42a(a)(1).

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.03		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

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Emission Unit Compliance Certification (continuation)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00003		P01		NY075 - 00 - 0	Particulates

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

0.0063 lb/mmBtu PM emission limit from the auxiliary boiler based on the Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup and shutdown. The facility will use vendor emission guarantees and/or stack testing to ensure compliance with the BACT emission limit, as required.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
			EPA RM 5 & 201A/201

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

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0063		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

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Emission Unit Compliance Certification (continuation)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				
☒ Applicable Federal Requirement			❑ State Only Requirement			❑ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00001		P01, P02		7664 - 09 - 5		Sulfur Dioxide			

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

0.0022 lb/mmBtu SO2 emission limit from the combustion turbine/duct burner based on the Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by limiting sulfur content of the natural gas to 0.8 grains/scf.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	Natural Gas	ASTM D 4084-82

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.8		391	grains per standard cubic foot

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				
☒ Applicable Federal Requirement			❑ State Only Requirement			❑ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00001		P03		7664 - 09 - 5		Sulfur Dioxide			

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

0.0015 lb/mmBtu SO2 emission limit from the combustion turbine (with and without the duct burner) based on the Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by maintaining compliance with the fuel oil sulfur limit of 0.0015%.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	percent by weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

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Emission Unit Compliance Certification (continuation)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				
☒ Applicable Federal Requirement			☐ State Only Requirement			☐ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00002		P01, P02		7664 - 09 - 5		Sulfur Dioxide			

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

0.0022 lb/mmBtu SO2 emission limit from the combustion turbine/duct burner based on the Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by limiting sulfur content of the natural gas to 0.8 grains/scf.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	Natural Gas	ASTM D 4084-82

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.8		391	grains per standard cubic foot

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				
☒ Applicable Federal Requirement			☐ State Only Requirement			☐ Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
U - 00002		P03		7664 - 09 - 5		Sulfur Dioxide			

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

0.0015 lb/mmBtu SO2 emission limit from the combustion turbine (with and without the duct burner) based on the Higher Heating Value (HHV) of the fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by maintaining compliance with the fuel oil sulfur limit of 0.0015%.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	percent by weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

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Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00003		P01		7664 - 09 - 5	Sulfur Dioxide

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

0.0022 lb/mmBtu SO2 emission limit from the auxiliary boiler based upon Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup and shutdown. The facility will demonstrate compliance with the BACT emission limit by limiting the sulfur content of the natural gas to 0.8 grains/scf.

Work Practice	Process Material		Reference Test Method
Type	Code	Description	
04	012	Natural Gas	ASTM D 4084-82

Parameter		Manufacturer Name/Model No.
Code	Description	
32	Sulfur Content	TBD

Limit		Limit Units	
Upper	Lower	Code	Description
0.8		391	grains per standard cubic foot

Averaging Method		Monitoring Frequency		Reporting Requirements	
Code	Description	Code	Description	Code	Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

DEC ID

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00003		P01		7664 - 09 - 5	Sulfur Dioxide

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

0.0022 lb/mmBtu SO2 emission limit from the auxiliary boiler based upon Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup and shutdown. The facility will demonstrate compliance with the BACT emission limit by limiting the sulfur content of the natural gas to 0.8 grains/scf.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	Natural Gas	ASTM D 4084-82

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.8		391	grains per standard cubic foot

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

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Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P01, P02		07664 - 93 - 9	Sulfuric Acid Mist

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

0.0007 lb/mmBtu SAM emission limit from the combustion turbine (with and without duct burner) based upon Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by limiting sulfur content of the natural gas to 0.8 grains/scf.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	Natural Gas	ASTM D 4084-82

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.8		391	grains per standard cubic foot

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00001		P03		07664 - 93 - 9	Sulfuric Acid Mist

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

0.0005 lb/mmBtu SAM emission limit from the combustion turbine (with and without duct burner) based upon Higher Heating Value (HHV) of the gas and fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by maintaining compliance with the fuel oil sulfur limit of 0.0015%.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	percent by weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

DEC ID

Emission Unit Compliance Certification (continuation)

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P01, P02		07664 - 93 - 9	Sulfuric Acid Mist

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

0.0007 lb/mmBtu SAM emission limit from the combustion turbine (with and without duct burner) based upon Higher Heating Value (HHV) of the natural gas. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by limiting sulfur content of the natural gas to 0.8 grains/scf.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	012	Natural Gas	ASTM D 4084-82

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.8		391	grains per standard cubic foot

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	14	As Required	10	Upon Request

Rule Citation

Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
40	CFR	52	21	b	23				

☒ Applicable Federal Requirement ❑ State Only Requirement ❑ Capping

Emission Unit	Emission Point	Process	Emission Source	CAS No.	Contaminant Name
U - 00002		P03		07664 - 93 - 9	Sulfuric Acid Mist

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

0.0005 lb/mmBtu SAM emission limit from the combustion turbine (with and without duct burner) based upon Higher Heating Value (HHV) of the gas and fuel oil. This emission limit applies at all loads except during startup, shutdown and fuel switching. The facility will demonstrate compliance with the BACT emission limit by maintaining compliance with the fuel oil sulfur limit of 0.0015%.

Work Practice Type	Process Material Code	Process Material Description	Reference Test Method
04	007	Number 2 Oil	ASTM D 2880-71

Parameter Code	Parameter Description	Manufacturer Name/Model No.
32	Sulfur Content	TBD

Limit Upper	Limit Lower	Limit Units Code	Limit Units Description
0.0015		57	percent by weight

Averaging Method Code	Averaging Method Description	Monitoring Frequency Code	Monitoring Frequency Description	Reporting Requirements Code	Reporting Requirements Description
01	Maximum not to be exceeded	11	Per Delivery	10	Upon Request

DEC ID

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

Emission Unit	Emission Point	Process	Emission Source	
-				☐Applicable Federal Requirement ❑ State Only Requirement

Description

Rule Citation

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

Emission Unit	Emission Point	Process	Emission Source	
-				❑ Applicable Federal Requirement ❑ State Only Requirement

Description

Process Emissions Summary

❑ Continuation Sheet(s)

EMISSION UNIT	-		PROCESS	

CAS No.	Contaminant Name	% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined
- -						

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

EMISSION UNIT	-		PROCESS	

CAS No.	Contaminant Name	% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined
- -						

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

EMISSION UNIT	-		PROCESS	

CAS No.	Contaminant Name	% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined
- -						

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

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Section IV - Emission Unit Information (continued)

EMISSION UNIT	Emission Unit Emissions Summary			❑ Continuation Sheet(s)
-				
CAS No.	Contaminant Name			
- -				
ERP (lbs/yr)	PTE Emissions		Actual	
	(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)
CAS No.	Contaminant Name			
- -				
ERP (lbs/yr)	PTE Emissions		Actual	
	(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)
CAS No.	Contaminant Name			
- -				
ERP (lbs/yr)	PTE Emissions		Actual	
	(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)
CAS No.	Contaminant Name			
- -				
ERP (lbs/yr)	PTE Emissions		Actual	
	(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)

Compliance Plan

❑ Continuation Sheet(s)

For any emission units which are not in compliance at the time of permit application, 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 Requirement									
			Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
-												

Remedial Measure / Intermediate Milestones	R/I	Date Scheduled

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Section IV - Emission Unit Information (continued)

Request for Emission Reduction Credits

❑ Continuation Sheet(s)

EMISSION UNIT   -

Emission Reduction Description

Contaminant Emission Reduction Data

Baseline Period ___/___/___ to ___/___/___		Reduction Date	Reduction Method
		/ /	
CAS No.	Contaminant Name	ERC (lbs/yr) Netting	ERC (lbs/yr) Offset
- -			
- -			
- -			

Facility to Use Future Reduction

Name		APPLICATION ID
		- - /
Location Address		
❑ City / ❑ Town / ❑ Village	State	Zip

Use of Emission Reduction Credits

❑ Continuation Sheet(s)

EMISSION UNIT   -

Proposed Project Description

Contaminant Emissions Increase Data

CAS No.	Contaminant Name	PEP (lbs/yr)
- -		

Statement of Compliance

❑ All facilities under the ownership of this "ownership/firm" are operating in compliance with all applicable requirements and state regulations including any compliance certification requirements under Section 114(a)(3) of the Clean Air Act Amendments of 1990, or are meeting the schedule of a consent order.

Source of Emission Reduction Credit - Facility

Name		PERMIT ID
		- - /
Location Address		
❑ City / ❑ Town / ❑ Village	State	Zip

Emission Unit	CAS No.	Contaminant Name	ERC (lbs/yr) Netting	ERC (lbs/yr) Offset
-	- -			

DEC ID											

Supporting Documentation

☒ P.E. Certification (form attached)

❑ List of Exempt Activities (form attached)

☒ 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): ______________________________ (/ /)
______________________________ (/ /)
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- -

P.E. Certification

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 as they pertain to the practice of engineering. This is defined as the performance of a professional service such as consultation, investigation, evaluation, planning, design or supervision of construction or operation in connection with any utilities, structures, buildings, machines, equipment, processes, works, or projects wherein the safeguarding of life, health and property is concerned, when such service or work requires the application of engineering principals and data. Based on my inquiry of those individuals with primary responsibility for obtaining such 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 of P.E. Mark M. Hultman

Signature of P.E. Mark M. Hultman

Date 11 / 24 / 2008

NYS License No. 068581

Phone ( ) 860-298-6245

APPENDIX B

EMISSION CALCULATIONS

Appendix B: Table B-1
CPV Valley Energy Center
Combined Cycle Turbine Emissions
Natural Gas Firing

SWPC 5000F Combustion Turbine in Combined Cycle Mode

GT Operating Mode																	Startup Emissions		
Ambient Temp, °F		-5	-5	-5	-5	51	51	51	51	51	90	90	90	90	90	90	51	51	51
% Load		BASE	BASE	80%	60%	BASE	BASE	BASE	80%	60%	BASE	BASE	BASE	BASE	80%	60%	Cold Start	Warm Start	Hot Start
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Evaporative Cooler Operation (85% effectiveness)		Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	Off	Off	Off	Off	Off	Off	Off
Combustion Turbine (CTG) Heat Input, mmBtu/hr (HHV)		2,234	2,234	2,083	1,551	1,998	1,998	1,998	1,861	1,364	1,855	1,855	1,855	1,855	1,689	1,243	1,364	1,364	1,364
Duct Burner Operation		Off	On	Off	Off	On	On	Off	Off	Off	On	Off	On	Off	Off	Off	Off	Off	Off
Duct Burner Heat Input, mmBtu/hr (HHV)		--	500.0	--	--	185.4	500.0	--	--	--	500.0	--	500.0	--	--	--	--	--	--
Combined Power Output of 2 CTG's & STG, MW		669.6	669.6	458.8	349.5	649.3	649.3	604.9	401.8	88.2	653.2	549.7	653.2	549.7	352.8	270.8	-	-	-
Controlled CTG and DB Pollutant Concentrations																			
NO_x	ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.00	2.00	2.0	2.0	2.0	2.00	2.0	2.00	2.0	2.0	2.0	-	-	-
CO	ppmvd @ 15% O_2	2.0	3.3	2.0	2.0	2.66	3.44	2.0	2.0	2.0	3.50	2.0	3.55	2.0	2.0	2.0	-	-	-
VOC	ppmvd @ 15% O_2	0.7	1.6	0.7	0.7	1.12	1.67	0.7	0.7	0.7	1.72	0.7	1.77	0.7	0.7	0.7	-	-	-
NH_3	ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	-	-	-
Controlled CTG and DB Emission Factors, lb/mmBtu (HHV)																			
NO_x		0.0075	0.0093	0.0068	0.0074	0.0076	0.0076	0.0075	0.0067	0.0075	0.0076	0.0075	0.0074	0.0073	0.0068	0.0075	-	-	-
CO		0.0046	0.0090	0.0041	0.0179	0.0059	0.0077	0.0046	0.0041	0.0183	0.0078	0.0045	0.0077	0.0044	0.0041	0.0183	-	-	-
VOC		0.0009	0.0025	0.0008	0.0027	0.0014	0.0021	0.0009	0.0008	0.0028	0.0022	0.0009	0.0022	0.0009	0.0008	0.0028	-	-	-
SO_2		0.0022	0.0027	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	-	-	-
Sulfuric Acid Mist (H_2SO_4)		0.0007	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	-	-	-
PM/PM-10/PM-2.5 (filterables, condensibles and sulfates)		0.0050	0.0074	0.0047	0.0061	0.0055	0.0062	0.0051	0.0052	0.0068	0.0064	0.0052	0.0064	0.0052	0.0056	0.0073	-	-	-
Controlled CTG and DB Stack Emissions, lb/hr																	Emissions		
NO_x		16.80	20.80	14.08	11.44	16.52	19.04	15.04	12.56	10.24	17.92	13.92	17.52	13.52	11.44	9.36	35.44	40.95	38.02
CO		10.20	20.20	8.60	27.80	12.91	19.20	9.20	7.60	25.00	18.40	8.40	18.20	8.20	7.00	22.80	269.05	333.56	329.71
VOC		2.03	5.53	1.75	4.20	3.12	5.32	1.82	1.54	3.78	5.18	1.68	5.18	1.68	1.40	3.43	53.07	57.56	51.83
SO_2		4.87	5.96	4.54	3.38	4.76	5.45	4.36	4.06	2.97	5.13	4.04	5.13	4.04	3.68	2.71	-	-	-
SO_3		1.22	1.49	1.14	0.85	1.19	1.36	1.09	1.01	0.74	1.28	1.01	1.28	1.01	0.92	0.68	-	-	-
NH_3		11.93	11.93	10.20	8.69	10.89	10.89	10.89	9.37	8.02	9.90	9.90	9.69	9.69	8.46	7.26	-	-	-
Sulfuric Acid Mist (H_2SO_4)		1.49	1.83	1.39	1.04	1.46	1.67	1.33	1.24	0.91	1.57	1.24	1.57	1.24	1.13	0.83	-	-	-
Ammonia Sulfates ($(NH_4)_2SO_4$)		2.01	2.46	1.87	1.40	1.96	2.25	1.80	1.67	1.23	2.12	1.67	2.12	1.67	1.52	1.12	-	-	-
PM-10 (filterables and condensables)		9.10	14.10	8.00	8.00	10.15	13.30	8.30	8.00	8.00	13.00	8.00	13.00	8.00	8.00	8.00	-	-	-
PM-10 (filterables, condensables and sulfates)		11.11	16.56	9.87	9.40	12.12	15.55	10.10	9.67	9.23	15.12	9.67	15.12	9.67	9.52	9.12	9.66	9.65	9.40
Stack Parameters																			
Stack Diameter, m		5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Stack Diameter, ft		19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Exhaust Flow per Stack, lb/hr		4,332	4,353	3,700	3,143	3,974	3,988	3,966	3,407	2,909	3,688	3,667	3,598	3,577	3,116	2,670	1,454	1,454	1,454
Exhaust Volume, acfm		1,231,680	1,237,785	1,043,520	870,780	1,122,688	1,126,505	1,120,440	950,460	802,740	1,061,761	1,055,580	1,061,916	1,055,580	867,720	740,100	401,370	401,370	401,370
Stack Exit Velocity, ft/s		72.4	72.8	61.3	51.2	66.0	66.2	65.9	55.9	47.2	62.4	62.1	62.4	62.1	51.0	43.5	23.6	23.6	23.6
Stack Exit Velocity, m/s		22.1	22.2	18.7	15.6	20.1	20.2	20.1	17.0	14.4	19.0	18.9	19.0	18.9	15.5	13.3	7.2	7.2	7.2
Stack Exit Temperature, °F		195	195	182	179	182	182	189	178	176	183	183	196	196	175	173	113.5	113.5	113.5
Stack Exit Temperature, deg K				356.5	354.8	356.5	356.5	360.4	354.3	353.2	357.0	357.0	364.3	364.3	352.6	351.5	318.4	318.4	318.4
Emission Rates, g/s																			
NO_x		2.117	2.621	1.774	1.441	2.082	2.399	1.895	1.583	1.290	2.258	1.754	2.208	1.704	1.441	1.179	4.466	5.160	4.791
CO		1.285	2.545	1.084	3.503	1.626	2.419	1.159	0.958	3.150	2.318	1.058	2.293	1.033	0.882	2.873	33.900	42.028	41.544
VOC		0.256	0.697	0.221	0.529	0.393	0.670	0.229	0.194	0.476	0.653	0.212	0.653	0.212	0.176	0.432	6.687	7.252	6.531
SO_2		0.614	0.751	0.572	0.426	0.600	0.686	0.549	0.511	0.375	0.647	0.510	0.647	0.510	0.464	0.341	-	-	-
Sulfuric Acid Mist (H_2SO_4)		0.188	0.230	0.175	0.131	0.184	0.210	0.168	0.157	0.115	0.198	0.156	0.198	0.156	0.142	0.105	-	-	-
PM-10 (filterables and condensables)		1.147	1.777	1.008	1.008	1.279	1.676	1.046	1.008	1.008	1.638	1.008	1.638	1.008	1.008	1.008	-	-	-
PM-10 (filterables, condensables and sulfates)		1.400	2.086	1.244	1.184	1.527	1.959	1.272	1.219	1.163	1.905	1.218	1.905	1.218	1.199	1.149	1.217	1.216	1.184

Notes:

1) Proposed method of emission control for NO_x is Dry Low-NO_x Burners and SCR when firing natural gas.

2) Sulfur Trioxide, Sulfuric Acid Mist and Ammonia Sulfates emissions are calculated by the following methodology:

SO_2 ----> SO_3 conversion = 20%

SO_3 lb/hr = SO_2 lb/hr * (80 MW_{SO3}/64 MW_{SO2}) * 20%

H_2SO_4 lb/hr = SO_3 lb/hr * (98 MW_{H2SO4}/80 MW_{SO3})

$(NH_4)_2SO_4$ lb/hr = H_2SO_4 lb/hr * (132 $MW_{(NH4)2SO4}$/98 MW_{H2SO4})

Appendix B: Table B-2
CPV Valley Energy Center
Combined Cycle Turbine Emissions
Distillate Oil Firing

SWPC 5000F Combustion Turbine in Combined Cycle Mode

GT Operating Mode											Startup Emissions		
Ambient Temp (^oF)	-5	-5	-5	51	51	51	90	90	90	90	51	51	51
% Load	100%	85%	70%	BASE	85%	70%	BASE	BASE	85%	70%	Cold Start	Warm Start	Hot Start
Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
Evaporative Cooler Operation (85% effectiveness)	Off	Off	Off	Off	Off	Off	On	Off	Off	Off	Off	Off	On
Combustion Turbine (CTG) Heat Input, mmBtu/hr (HHV)	2,145	1,867	1,606	1,894	1,662	1,436	1,757	1,698	1,504	1,303	1,435.9	1435.9	1435.9
Combined Power Output of 2 CTG's & STG (MW)	635.6	456.8	380.0	566.3	400.1	332.7	516.9	501.5	351.3	293.3	-	-	-
Controlled CTG Pollutant Concentrations													
NO_x ppmvd @ 15% O_2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	-	-	-
CO ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	-	-	-
VOC ppmvd @ 15% O_2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	-	-	-
NH_3 ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	-	-	-
Controlled CTG Emission Factors, lb/mmBtu (HHV)													
NO_x	0.0240	0.0239	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	-	-	-
CO	0.0035	0.0073	0.0146	0.0049	0.0073	0.0146	0.0049	0.0048	0.0073	0.0146	-	-	-
VOC	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	-	-	-
SO_2	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	-	-	-
Sulfuric Acid Mist (H_2SO_4)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	-	-	-
PM/PM-10/PM-2.5 (filterables, condensibles and sulfates)	0.0239	0.0242	0.0361	0.0244	0.0247	0.0368	0.0240	0.0242	0.0246	0.0367	-	-	-
Controlled CTG Stack Emissions, lb/hr												Emissions	
NO_x	51.43	44.71	38.57	45.43	39.86	34.43	42.14	40.71	36.14	31.29	81.48	91.74	87.19
CO	7.43	13.60	23.40	9.20	12.20	21.00	8.60	8.20	11.00	19.00	323.48	375.76	369.52
VOC	2.10	1.82	1.54	1.82	1.61	1.40	1.68	1.68	1.47	1.26	187.12	198.28	173.61
SO_2	3.27	2.85	2.45	2.89	2.53	2.19	2.68	2.59	2.29	1.99	-	-	-
SO_3	0.82	0.71	0.61	0.72	0.63	0.55	0.67	0.65	0.57	0.50	-	-	-
Sulfuric Acid Mist (H_2SO_4)	1.00	0.87	0.75	0.88	0.78	0.67	0.82	0.79	0.70	0.61	-	-	-
Ammonia Sulfates ($(NH_4)_2SO_4$)	1.35	1.17	1.01	1.19	1.04	0.90	1.10	1.07	0.95	0.82	-	-	-
PM-10 (filterables and condensables)	50.00	44.00	57.00	45.00	40.00	52.00	41.00	40.00	36.00	47.00	-	-	-
PM-10 (filterables, condensables and sulfates)	51.35	45.17	58.01	46.19	41.04	52.90	42.10	41.07	36.95	47.82	53.05	52.40	52.16
Stack Parameters													
Stack Diameter, m	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Stack Diameter, ft	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Exhaust Flow per Stack (lb/hr)	4,442	3,906	3,500	4,015	3,587	3,231	3,712	3,621	3,277	2,955	1,615	1,615	1,615
Exhaust Volume, acfm	1,274,010	1,111,200	976,380	1,147,230	1,005,240	894,180	1,069,140	1,069,140	895,050	824,100	447,090	447,090	447,090
Stack Exit Velocity, ft/s	74.9	65.3	57.4	67.4	59.1	52.6	62.8	62.8	52.6	48.4	26.3	26.3	26.3
Stack Exit Velocity, m/s	22.8	19.9	17.5	20.6	18.0	16.0	19.2	19.2	16.0	14.8	8.0	8.0	8.0
Stack Exit Temperature, ^oF	209	192	192	204	185	185	203	203	185	185	118	118	118
Stack Exit Temperature, deg K	371.5	362.0	362.0	368.7	358.2	358.2	368.2	368.2	358.2	358.2	320.9	320.9	320.9
Emission Rates, g/s													
NO_x	6.480	5.634	4.860	5.724	5.022	4.338	5.310	5.130	4.554	3.942	10.267	11.559	10.986
CO	0.936	1.714	2.948	1.159	1.537	2.646	1.084	1.033	1.386	2.394	40.759	47.345	46.559
VOC	0.265	0.229	0.194	0.229	0.203	0.176	0.212	0.212	0.185	0.159	23.577	24.983	21.875
SO_2	0.412	0.359	0.308	0.364	0.319	0.276	0.337	0.326	0.289	0.250	-	-	-
Sulfuric Acid Mist (H_2SO_4)	0.126	0.110	0.094	0.111	0.098	0.084	0.103	0.100	0.088	0.077	-	-	-
PM-10 (filterables and condensables)	6.300	5.544	7.182	5.670	5.040	6.552	5.166	5.040	4.536	5.922	-	-	-
PM-10 (filterables, condensables and sulfates)	6.470	5.692	7.309	5.820	5.172	6.666	5.305	5.175	4.655	6.025	6.685	6.603	6.572

Notes:

1) Proposed method of emission control for NO_x is water injection and SCR when firing fuel oil.
2) Sulfur Trioxide, Sulfuric Acid Mist and Ammonia Sulfates emissions are calculated by the following methodology:

SO_2 ----> SO_3 conversion = 20%

SO_3 lb/hr = SO_2 lb/hr * (80 MW_{SO3}/64 MW_{SO2}) * 20%

H_2SO_4 lb/hr = SO_3 lb/hr * (98 MW_{H2SO4}/80 MW_{SO3})

$(NH_4)_2SO_4$ lb/hr = H_2SO_4 lb/hr * (132 $MW_{(NH4)2SO4}$/98 MW_{H2SO4})

Appendix B: Table B-3
CPV Valley Energy Center
Combustion Turbine Natural Gas Startup and Shutdown Emissions

Estimated Siemens SGT6-5000F Startup and Shutdown emissions-Natural Gas.

Event	*Elapsed Time(hr)*	*Turbine NOx (1) (lb/event)*	*Stack NOx (1) (lb/event)*	*Turbine CO (lb/event)*	*Stack CO (lb/event)*	*VOC (2) (lb/event)*	*Particulates (lb/event)*
Cold Start (3), 1st CTG	*2.87*	*337*	*95*	*4,012*	*630*	*150*	*28*
2nd CTG	*1.45*	*157*	*58*	*2,386*	*532*	*79*	*14*
Warm Start (4)	*1.95*	*234*	*77*	*3,123*	*569*	*112*	*19*
	1.28	*131*	*56*	*2,141*	*510*	*74*	*12*
Hot Start (5)	*1.80*	*177*	*62*	*2,320*	*479*	*91*	*17*
	0.97	*87*	*44*	*1,524*	*433*	*53*	*9*
Shut Down	*1.00*	*60*	*43*	*842*	*127*	*22*	*8*

1 As NO_2
2 As CH_4
3 Startup after 72 hour shutdown
4 Startup after 48 hour shutdown
5 Startup after 8 hour shutdown

The above data has been determined based on the following assumptions:
1. Auxiliary Boiler in operation to pre-heat HRSG during start-up.
2. Emissions are estimated based upon data provided by Siemens on 10-29-2007.
3. NOx Catalyst sized to produce 2 ppmvd at GT full load with duct firing.
4. CO and VOC reductions based upon Catalyst performance provided by VOGT dated on 11-05-07.
5. Stack damper installed to maintain HRSG hot during shut down.

	Type of Start-up or Shut-down Event			
	Cold Startup	Warm Startup	Hot Startup	Shutdown
Duration of Turbine at 0% load prior to Start-up (hr)	>48	8.1 to 48	0 to 8	--
Maximum Duration of Start-up or Shut-down Event (hr)	2.9	2.1	1.8	1
Nox (Lb/hr)	33.00	39.28	34.22	42.50
VOC (Lb/hr)	52.43	57.49	50.44	21.60
CO (Lb/hr)	219.59	291.64	266.17	127.20

Appendix B: Table B-4
CPV Valley Energy Center
Combustion Turbine Fuel Oil Startup and Shutdown Emissions

Estimated Siemens SGT6-5000F Startup and Shutdown emissions-Fuel Oil.

Event	*Elapsed Time(hr)*	*Turbine NOx (1) (lb/event)*	*Stack NOx (1) (lb/event)*	*Turbine CO (lb/event)*	*Stack CO (lb/event)*	*VOC (2) (lb/event)*	*Particulates (lb/event)*
Cold Start (3), 1st CTG	*3.03*	*839*	*233*	*6,885*	*847*	*574*	*162*
2nd CTG	*1.62*	*406*	*146*	*3,727*	*657*	*296*	*84*
Warm Start (4)	*2.12*	*580*	*187*	*4,997*	*721*	*430*	*112*
	1.45	*348*	*140*	*3,303*	*619*	*277*	*75*
Hot Start (5)	*1.97*	*480*	*158*	*4,109*	*623*	*341*	*104*
	1.13	*251*	*112*	*2,186*	*523*	*197*	*58*
Shut Down	*1.00*	*195*	*111*	*1,200*	*169*	*87*	*42*

1 *As NO_2*
2 *As CH_4*
3 *Startup after 72 hour shutdown*
4 *Startup after 48 hour shutdown*
5 *Startup after 8 hour shutdown*

The above data has been determined based on the following assumptions:

1. Auxiliary Boiler in operation to pre-heat HRSG during start-up.
2. Emissions are estimated based upon data provided by Siemens on 10-29-2007.
3. NOx Catalyst sized to produce 5.9 ppmvd at GT full load w/ duct firing.
4. CO and VOC reductions based upon Catalyst performance provided by VOGT dated on 11-05-07.
5. Stack damper installed to maintain HRSG hot during shut down.

	Type of Start-up or Shut-down Event			
	Cold Startup	Warm Startup	Hot Startup	Shutdown
Duration of Turbine at 0% load prior to Start-up (hr)	>48	8.1 to 48	0 to 8	--
Maximum Duration of Start-up or Shut-down Event (hr)	3	2.1	2	1
Nox (Lb/hr)	76.71	88.25	80.39	110.80
VOC (Lb/hr)	189.20	203.24	173.34	86.90
CO (Lb/hr)	279.16	340.58	316.78	168.50

Appendix B: Table B-5
CPV Valley Energy Center
Combustion Turbine Startup and Shutdown Emissions Summary

Event	Fuel	Duration of Shutdown Prior to Startup (hours)	Duration (hours)	NO_x			CO			VOC			PM10		
				total (lb)	rate (lb/hr)	rate (gram/sec)	total (lb)	rate (lb/hr)	rate (gram/sec)	total (lb)	rate (lb/hr)	rate (gram/sec)	total (lb)	rate (lb/hr)	rate (gram/sec)
Cold Startup	Natural Gas	>48	2.2	76.5	35.4	4.5	580.7	269.1	33.9	114.6	53.1	6.7	20.9	9.7	1.2
Cold Startup	Distillate Oil	>48	2.3	189.5	81.5	10.3	752.1	323.5	40.8	435.1	187.1	23.6	123.4	53.1	6.7
Warm Startup	Natural Gas	8.1 to 48	1.6	66.2	40.9	5.2	539.3	333.6	42.0	93.1	57.6	7.3	15.6	9.6	1.2
Warm Startup	Distillate Oil	8.1 to 48	1.8	163.6	91.7	11.6	670.1	375.8	47.3	353.6	198.3	25.0	93.5	52.4	6.6
Hot Startup	Natural Gas	0 to 8	1.4	52.6	38.0	4.8	456.1	329.7	41.5	71.7	51.8	6.5	13.0	9.4	1.2
Hot Startup	Distillate Oil	0 to 8	1.6	135.2	87.2	11.0	572.8	369.5	46.6	269.1	173.6	21.9	80.9	52.2	6.6
Shutdown	Natural Gas		1.0	42.5	42.5	5.4	127.2	127.2	16.0	21.6	21.6	2.7	8.0	8.0	1.0
Shutdown	Distillate Oil		1.0	110.8	110.8	14.0	168.5	168.5	21.2	86.9	86.9	10.9	42.4	42.4	5.3

(1) Emissions are for a single unit

Appendix B: Table B-6
CPV Valley Energy Center
Potential Emissions Summary
Maximum Combined Cycle PTE for any Annual Operating Scenario

Annual Operating Scenario		Natural Gas Only Operation				Gas/Oil Operation			
Maximum Annual Operation With No Startups				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
Annual Turbine Operation, hr/yr				8,760	17,520			8,760	17,520
Annual Turbine Operation on Natural Gas, hr/yr				8,760	17,520			8,040	16,080
Annual Turbine Operation on Fuel Oil, hr/yr				0	0			720	1,440
DB Capacity Factor of Annual Turbine Operation				30%				30%	
Annual DB Operation on Natural Gas, hr/yr				2,628	5,256			2,628	5,256
Annual Generation, MWhr/yr					5,415,245				5,437,381
Annual Emissions, tons/yr				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
NO_x				71.13	142.3			84.23	168.5
CO				101.88	203.8			101.30	202.6
VOC				18.58	37.2			17.98	36.0
SO_2				20.51	41.0			20.12	40.2
H_2SO_4				6.28	12.6			6.16	12.3
PM/PM-10/PM-2.5				51.4	102.8			68.6	137.3
Annual Operation With Cold & Warm Startups				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
Number of Start-Ups on Natural Gas	Cold			40	80			36	72
	Warm			235	470			219	438
	Hot			0	0			0	0
Number of Shut Downs on Natural Gas				275	550			255	510
Operating Time Attributed to Gas SUSD, hr/yr				741	1,483			687	1,374
Downtime Prior to Natural Gas Startups, hr/yr				3,800	7,600			3,480	6,960
Number of Start-Ups on Fuel Oil	Cold			0	0			4	8
	Warm			0	0			16	32
	Hot			0	0			0	0
Number of Shut Downs on Fuel Oil				0	0			20	40
Operating Time Attributed to Oil SUSD, hr/yr				0	0			58	116
Downtime Prior to Fuel Oil Startups, hr/yr				0	0			320	640
Annual Turbine Operation on Natural Gas, hr/yr				4,219	8,438			3,553	7,107
Annual Turbine Operation on Fuel Oil, hr/yr				0	0			662	1,324
DB Capacity Factor of Annual Turbine Operation				30%				30%	
Annual DB Operation on Natural Gas, hr/yr				2,628	5,256			2,628	5,256
Annual Generation, MWhr/yr					2,668,470				2,686,812
		Per Unit		**Per Unit**	**2-Unit Total**	**Per Unit**		**Per Unit**	**2-Unit**
Annual Emissions, tons/yr		**Operation**	**Start-Ups**	**Total**	**Total**	**Operation**	**Start-Ups**	**Total**	**Total**
NO_x		36.98	15.15	52.1	104.3	49.00	16.84	65.8	131.7
CO		45.11	92.47	137.6	275.2	44.54	94.27	138.8	277.6
VOC		10.00	16.19	26.2	52.4	9.43	19.57	29.0	58.0
SO_2		10.62	0	10.6	21.2	10.26	0.00	10.3	20.5
H_2SO_4		3.25	0	3.3	6.5	3.14	0.00	3.1	6.3
Annual Operation With Cold & Hot Startups				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
Number of Start-Ups on Natural Gas	Cold			40	80			36	72
	Warm			0	0			0	0
	Hot			235	470			219	438
Number of Shut Downs on Natural Gas				275	550			255	510
Operating Time Attributed to Gas SUSD, hr/yr				686	1,373			636	1,271
Downtime Prior to Natural Gas Startups, hr/yr				2,390	4,780			2,166	4,332
Number of Start-Ups on Fuel Oil	Cold			0	0			4	8
	Warm			0	0			0	0
	Hot			0	0			16	32
Number of Shut Downs on Fuel Oil				0	0			20	40
Operating Time Attributed to Oil SUSD, hr/yr				0	0			54	108
Downtime Prior to Fuel Oil Startups, hr/yr				0	0			224	448
Annual Turbine Operation on Natural Gas, hr/yr				5,684	11,367			5,014	10,029
Annual Turbine Operation on Fuel Oil, hr/yr				0	0			666	1,332
DB Capacity Factor of Annual Turbine Operation				30%				30%	
Annual DB Operation on Natural Gas, hr/yr				2,628	5,256			2,628	5,256
Annual Generation, MWhr/yr					3,554,475				3,170,161
		Per Unit		**Per Unit**	**2-Unit**	**Per Unit**		**Per Unit**	**2-Unit**
Annual Emissions, tons/yr		**Operation**	**Start-Ups**	**Total**	**Total**	**Operation**	**Start-Ups**	**Total**	**Total**
NO_x		48.00	13.55	61.6	123.1	60.09	15.12	75.2	150.4
CO		63.42	82.70	146.1	292.2	62.85	84.38	147.2	294.5
VOC		12.77	13.69	26.5	52.9	12.20	16.56	28.8	57.5
SO_2		13.81	0	13.8	27.6	13.44	0	13.4	26.9
H_2SO_4		4.23	0	4.2	8.5	4.12	0	4.1	8.2
Annual Operation With All Warm Startups				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
Number of Start-Ups on Natural Gas	Cold			0	0			0	0
	Warm			275	550			255	510
	Hot			0	0			0	0
Number of Shut Downs on Natural Gas				275	550			255	510
Operating Time Attributed to Gas SUSD, hr/yr				720	1,439			667	1,335
Downtime Prior to Natural Gas Startups, hr/yr				2,200	4,400			2,040	4,080
Number of Start-Ups on Fuel Oil	Cold			0	0			4	8
	Warm			0	0			16	32
	Hot			0	0			0	0
Number of Shut Downs on Fuel Oil				0	0			20	40
Operating Time Attributed to Oil SUSD, hr/yr				0	0			58	116
Downtime Prior to Fuel Oil Startups, hr/yr				0	0			320	640
Annual Turbine Operation on Natural Gas, hr/yr				5,840	11,681			5,013	10,026
Annual Turbine Operation on Fuel Oil, hr/yr				0	0			662	1,324
DB Capacity Factor of Annual Turbine Operation				30%				30%	
Annual DB Operation on Natural Gas, hr/yr				2,628	5,256			2,628	5,256
Annual Generation, MWhr/yr					3,649,335				3,569,590
		Per Unit		**Per Unit**	**2-Unit Total**	**Per Unit**		**Per Unit**	**2-Unit**
Annual Emissions, tons/yr		**Operation**	**Start-Ups**	**Total**	**Total**	**Operation**	**Start-Ups**	**Total**	**Total**
NO_x		49.18	14.95	64.1	128.2	59.98	16.65	76.6	153.3
CO		65.38	91.64	157.0	314.0	62.79	93.52	156.3	312.6
VOC		13.06	15.76	28.8	57.7	12.19	19.19	31.4	62.8
SO_2		14.15	0	14.2	28.3	13.43	0	13.4	26.9
H_2SO_4		4.33	0	4.3	8.7	4.11	0	4.1	8.2
Annual Operation With All Hot Startups				**Per Unit**	**2-Unit Total**			**Per Unit**	**2-Unit Total**
Number of Start-Ups on Natural Gas	Cold			0	0			0	0
	Warm			0	0			0	0
	Hot			275	550			255	510
Number of Shut Downs on Natural Gas				275	550			255	510
Operating Time Attributed to Gas SUSD, hr/yr				655	1,311			608	1,216
Downtime Prior to Natural Gas Startups, hr/yr				550	1,100			510	1,020
Number of Start-Ups on Fuel Oil	Cold			0	0			4	8
	Warm			0	0			0	0
	Hot			0	0			16	32
Number of Shut Downs on Fuel Oil				0	0			20	40
Operating Time Attributed to Oil SUSD, hr/yr				0	0			54	108
Downtime Prior to Fuel Oil Startups, hr/yr				0	0			224	448
Annual Turbine Operation on Natural Gas, hr/yr				7,555	15,109			6,698	13,397
Annual Turbine Operation on Fuel Oil, hr/yr				0	0			666	1,332
DB Capacity Factor of Annual Turbine Operation				30%				30%	
Annual DB Operation on Natural Gas, hr/yr				2,628	5,256			2,628	5,256
Annual Generation, MWhr/yr					4,686,149				4,188,668
		Per Unit		**Per Unit**	**2-Unit**	**Per Unit**		**Per Unit**	**2-Unit**
Annual Emissions, tons/yr		**Operation**	**Start-Ups**	**Total**	**Total**	**Operation**	**Start-Ups**	**Total**	**Total**
NO_x		62.07	13.08	75.1	150.3	72.75	14.69	87.4	174.9
CO		86.81	80.20	167.0	334.0	83.90	82.14	166.0	332.1
VOC		16.30	12.83	29.1	58.3	15.38	15.79	31.2	62.3
SO_2		17.89	0	17.9	35.8	17.11	0	17.1	34.2
H_2SO_4		5.48	0	5.5	11.0	5.24	0	5.2	10.5

Appendix B: Table B-7
CPV Valley Energy Center
Proposed Potential Emissions for the Auxiliary Boiler

Operating Hours	2000	Stack Parameters	
Fuel Type	Nat Gas	Stack ID (ft.)	19.0
Fuel Heating Value, HHV (Btu/scf)	1,048	Exhaust Flow (acfm)	19,301
Standard Cubic Feet per Hour	70,116	Stack Velocity (ft/min)	68
Fuel Input in MMBtu per Hour (HHV)	73.5	Stack Velocity (m/sec)	0.3
Annual Fuel Usage (scf/year)	1.40E+08	Stack Temperature (°F)	300

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/scf)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)
Criteria Air Pollutants					
NOx	4.50E-02		1	3.31	3.31
CO	7.21E-02		1	5.30	5.30
SOx	2.18E-03		1	0.16	0.16
VOC	3.78E-03		1	0.28	0.28
$PM_{10}/PM_{2.5}$	6.31E-03		1	0.46	0.46
PM	6.31E-03		1	0.46	0.46
Sulfuric Acid	1.67E-04		2	1.23E-02	1.23E-02

1. PB Power, Inc.
2. Assume that 5% of SO_2 is converted to H_2SO_4

Appendix B: Table B-8
CPV Valley Energy Center
Proposed Potential Emissions for the Gas Heater

Operating Parameters:

Operating Hours	8760
Fuel Type	Nat Gas
Fuel Heating Value, HHV (Btu/scf)	1,048
Fuel Input, HHV (MMBtu/hr)	5.02
Number of heaters	2

Stack Parameters:

Stack Height (ft.)	26
Stack Height (m.)	7.92
Stack Temperature (°F)	850
Stack Temperature (°K)	727.6
Stack Velocity (ft/s)	16.07
Stack Velocity (m/s)	4.9
Stack ID (ft.)	2.0
Stack ID (m.)	0.61

Pollutant	**Emission Factor**	**Short-Term Emissions (per heater)**		**Total Annual Emissions**
	(lb/mmBtu)	**(lb/hr)**	**(g/s)**	**(ton/yr)**
Criteria Air Pollutants				
CO	0.0840	0.4219	0.0532	3.70
NO_x	0.0575	0.289	0.0364	2.53
SO_2	0.0022	0.011	0.0014	0.10
VOC	0.0110	0.055	0.0070	0.48
PM10/PM2.5	0.0076	0.038	0.0048	0.33
PM	0.0076	0.038	0.0048	0.33
Sulfuric Acid	0.00017	0.001	0.0001	0.01

Appendix B: Table B-9
CPV Valley Energy Center
Proposed Potential Emissions for the Emergency Generator

Operating Hours	500	Generator Efficiency	95%
Fuel Type	ULSD	Engine Horsepower	2,117
Fuel Heating Value, HHV (Btu/gal)	139,728	Stack Parameters	
Gallon per Hour	110.4	Stack ID (ft.)	1.5
Assumed Heat Rate (Btu/kW-hr)	10,287	Exhaust Flow (acfm)	11,061
Fuel Input in MMBtu per Hour	15.43	Stack Velocity (ft/min)	6,259
Output in kW	1,500	Stack Velocity (m/sec)	31.8
Annual Fuel Usage (gallon/year)	55,216	Stack Temperature (°F)	764
Sulfur Content of Fuel	0.0015%		

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)
Criteria Air Pollutants					
NOx		4.97	2	23.20	5.80
CO		0.45	2	2.10	0.53
SOx	1.38E-03		4	0.0213	5.33E-03
VOC		0.11	2	0.51	0.13
$PM_{10}/PM_{2.5}$		0.03	2	0.14	0.04
PM		0.03	2	0.14	0.04
Sulfuric Acid	3.10E-05		3,4	4.79E-04	1.20E-04

1. Stack exhaust temperature and flow from Caterpillar data sheet (CAT3512C Diesel Engine)
2. Emission factors based on Caterpillar data sheet (CAT3512C Diesel Engine) and are NSPS Subpart IIII compliant. Emissions calculated assuming 95% efficiency.
3. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
4. Mass balance

Appendix B: Table B-10
CPV Valley Energy Center
Proposed Potential Emissions for the Fire Water Pump Engine

Operating Hours	500
Fuel Type	ULSD
Fuel Heating Value, HHV (Btu/gal)	139,728
Gallons per Hour	16.3
Assumed Efficiency	36%
Fuel Input (MMBtu/hr)	2.27
BHP Rating	325
Assumed Heat Rate (Btu/kW-hr)	10,287
Annual Fuel Usage (gal/year)	8,140
Sulfur Content in Fuel	0.0015%

Stack Parameters[5]	
Stack ID (ft.)	0.50
Exhaust Flow (acfm)	1,605
Stack Velocity (ft/min)	8,174
Stack Velocity (m/sec)	41.5
Stack Temperature (°F)	952

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (g/kW-hr)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)
Criteria Air Pollutants					
NOx	8.57E-01	4.00	1	1.95	0.488
CO	7.50E-01	3.50	1	1.71	0.427
SOx	1.43E-03		6	3.25E-03	8.13E-04
VOC	0.36		2	0.82	0.205
$PM_{10}/PM_{2.5}$	4.29E-02	0.20	1	0.10	0.024
PM	4.29E-02	0.20	1	0.10	0.024
Sulfuric Acid	3.10E-05		3/4	7.06E-05	1.77E-05

1. Caterpillar 3406C data sheet states emission are Tier 1 compliant. For emission estimation purposes, assumed regulatory limit for NMHC+NOx as max emission rate for NOx and AP-42 for VOC emission rate. In no way will total NMHC+Nox emissions be greater than the standards specified in NSPS Subpart IIII.
2. AP-42, 5th Edition Tables 3.3-1 and 3.3-2, November 1996
3. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
4. Emission factor for sulfuric acid is 8.9(%S) ng/J.
5. Assumed same exhaust parameters as 317 bhp Cummins diesel engine which has stack exhaust gas flowrate of 1605 acfm at 952 °F.
6. Mass balance

Appendix B: Table B-11
CPV Valley Energy Center
Facility-Wide Potential to Emit[1,2]

Pollutant	Combined Cycle Units (tons/yr)	Auxiliary Boiler (tons/yr)	Emergency Diesel Generator (tons/yr)	Fire Pump (tons/yr)	Gas Heaters (tons/yr)	Oil Storage Tank (tons/yr)	Facility (tons/yr)
NO_x	174.9	3.31	5.80	0.49	2.53	N/A	187.0
CO	334.0	5.30	0.53	0.43	3.70	N/A	344.0
VOC	62.8	0.28	0.13	0.20	0.48	0.17	65.0
SO_2	41.0	0.16	0.01	0.00	0.10	N/A	42.0
PM/PM-10/PM-2.5	94.2	0.46	0.04	0.02	0.33	N/A	95.0
H_2SO_4	12.6	0.01	0.00012	0.00002	0.01	N/A	13.0
NH_3	104.8	N/A	N/A	N/A	N/A	N/A	104.8

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
(Page 1 of 6)

Fuel			**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**
Ambient Temp.		°F	90	90	90	90	90	90	51	51	51	51	51	-5	-5	-5	-5
Turbine Load			BASE	BASE	BASE	BASE	80%	60%	BASE	BASE	BASE	80%	60%	98%	98%	80%	60%
Inlet Air Cooling			On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Heat Input-HHV		mmBtu/hr	1,855	1,855	1,855	1,855	1,689	1,243	1,998	1,998	1,998	1,861	1,364	2,234	2,234	2,083	1,551
Duct Burner Status			On	Off	On	Off	Off	Off	On	On	Off	Off	Off	On	Off	Off	Off
Duct Burner Firing Rate		mmBtu/hr	500		500				185	500				500			
1,3-Butadiene	a	(lb/hr)	7.98E-04	7.98E-04	7.98E-04	7.98E-04	7.26E-04	5.35E-04	8.59E-04	8.59E-04	8.59E-04	8.00E-04	5.87E-04	9.60E-04	9.60E-04	8.96E-04	6.67E-04
1,1,1-Trichloroethane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,4-Dichlorobenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2-Methylnapthalene		(lb/hr)	1.18E-05	0.00E+00	1.18E-05	0.00E+00	0.00E+00	0.00E+00	4.36E-06	1.18E-05	0.00E+00	0.00E+00	0.00E+00	1.18E-05	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene	a,b	(lb/hr)	8.82E-07	0.00E+00	8.82E-07	0.00E+00	0.00E+00	0.00E+00	3.27E-07	8.82E-07	0.00E+00	0.00E+00	0.00E+00	8.82E-07	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene	a,b	(lb/hr)	7.84E-06	0.00E+00	7.84E-06	0.00E+00	0.00E+00	0.00E+00	2.91E-06	7.84E-06	0.00E+00	0.00E+00	0.00E+00	7.84E-06	0.00E+00	0.00E+00	0.00E+00
Acenaphthene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Acenaphthylene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Acetaldehyde	a	(lb/hr)	7.42E-02	7.42E-02	7.42E-02	7.42E-02	6.76E-02	5.53E-02	7.99E-02	7.99E-02	7.99E-02	7.44E-02	6.07E-02	8.93E-02	8.93E-02	8.33E-02	6.90E-02
Acrolein	a	(lb/hr)	1.19E-02	1.19E-02	1.19E-02	1.19E-02	1.08E-02	1.03E-02	1.28E-02	1.28E-02	1.28E-02	1.19E-02	1.13E-02	1.43E-02	1.43E-02	1.33E-02	1.29E-02
Ammonia		(lb/hr)	9.90E+00	9.90E+00	9.69E+00	9.69E+00	8.46E+00	7.26E+00	1.09E+01	1.09E+01	1.09E+01	9.37E+00	8.02E+00	1.19E+01	1.19E+01	1.02E+01	8.69E+00
Anthracene	a,b	(lb/hr)	2.12E-04	2.11E-04	2.12E-04	2.11E-04	1.92E-04	1.41E-04	2.28E-04	2.29E-04	2.27E-04	2.12E-04	1.55E-04	2.55E-04	2.54E-04	2.37E-04	1.77E-04
Arsenic	a	(lb/hr)	9.80E-05	0.00E+00	9.80E-05	0.00E+00	0.00E+00	0.00E+00	3.63E-05	9.80E-05	0.00E+00	0.00E+00	0.00E+00	9.80E-05	0.00E+00	0.00E+00	0.00E+00
Barium		(lb/hr)	2.16E-03	0.00E+00	2.16E-03	0.00E+00	0.00E+00	0.00E+00	8.00E-04	2.16E-03	0.00E+00	0.00E+00	0.00E+00	2.16E-03	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Benzene	a	(lb/hr)	2.33E-02	2.23E-02	2.33E-02	2.23E-02	2.03E-02	1.28E-01	2.44E-02	2.50E-02	2.40E-02	2.23E-02	1.40E-01	2.78E-02	2.68E-02	2.50E-02	1.60E-01
Benzo(a)pyrene	a,b	(lb/hr)	1.06E-04	1.06E-04	1.06E-04	1.06E-04	9.61E-05	7.07E-05	1.14E-04	1.14E-04	1.14E-04	1.06E-04	7.76E-05	1.28E-04	1.27E-04	1.18E-04	8.83E-05
Benzo(b)fluoranthene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Benzo(b,k)fluoranthene		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene	a,b	(lb/hr)	1.06E-04	1.06E-04	1.06E-04	1.06E-04	9.61E-05	7.07E-05	1.14E-04	1.14E-04	1.14E-04	1.06E-04	7.76E-05	1.28E-04	1.27E-04	1.18E-04	8.83E-05
Benzo(k)fluoranthene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Beryllium	a	(lb/hr)	5.88E-06	0.00E+00	5.88E-06	0.00E+00	0.00E+00	0.00E+00	2.18E-06	5.88E-06	0.00E+00	0.00E+00	0.00E+00	5.88E-06	0.00E+00	0.00E+00	0.00E+00
Butane		(lb/hr)	1.03E+00	0.00E+00	1.03E+00	0.00E+00	0.00E+00	0.00E+00	3.82E-01	1.03E+00	0.00E+00	0.00E+00	0.00E+00	1.03E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	a	(lb/hr)	5.39E-04	0.00E+00	5.39E-04	0.00E+00	0.00E+00	0.00E+00	2.00E-04	5.39E-04	0.00E+00	0.00E+00	0.00E+00	5.39E-04	0.00E+00	0.00E+00	0.00E+00
Carbon Tetrachloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorobenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chloroform	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium	a	(lb/hr)	6.86E-04	0.00E+00	6.86E-04	0.00E+00	0.00E+00	0.00E+00	2.54E-04	6.86E-04	0.00E+00	0.00E+00	0.00E+00	6.86E-04	0.00E+00	0.00E+00	0.00E+00
Chrysene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Cobalt	a	(lb/hr)	4.12E-05	0.00E+00	4.12E-05	0.00E+00	0.00E+00	0.00E+00	1.53E-05	4.12E-05	0.00E+00	0.00E+00	0.00E+00	4.12E-05	0.00E+00	0.00E+00	0.00E+00
Copper		(lb/hr)	4.17E-04	0.00E+00	4.17E-04	0.00E+00	0.00E+00	0.00E+00	1.54E-04	4.17E-04	0.00E+00	0.00E+00	0.00E+00	4.17E-04	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene	a,b	(lb/hr)	1.06E-04	1.06E-04	1.06E-04	1.06E-04	9.61E-05	7.07E-05	1.14E-04	1.14E-04	1.14E-04	1.06E-04	7.76E-05	1.28E-04	1.27E-04	1.18E-04	8.83E-05
Dichlorobenzene	a	(lb/hr)	5.88E-04	0.00E+00	5.88E-04	0.00E+00	0.00E+00	0.00E+00	2.18E-04	5.88E-04	0.00E+00	0.00E+00	0.00E+00	5.88E-04	0.00E+00	0.00E+00	0.00E+00
Ethane		(lb/hr)	1.52E+00	0.00E+00	1.52E+00	0.00E+00	0.00E+00	0.00E+00	5.63E-01	1.52E+00	0.00E+00	0.00E+00	0.00E+00	1.52E+00	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	a	(lb/hr)	5.94E-02	5.94E-02	5.94E-02	5.94E-02	5.40E-02	3.98E-02	6.39E-02	6.39E-02	6.39E-02	5.95E-02	4.37E-02	7.15E-02	7.15E-02	6.66E-02	4.96E-02
Ethylene Dichloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoranthene	a,b	(lb/hr)	2.65E-04	2.64E-04	2.65E-04	2.64E-04	2.40E-04	1.77E-04	2.85E-04	2.86E-04	2.84E-04	2.65E-04	1.94E-04	3.19E-04	3.18E-04	2.96E-04	2.21E-04
Fluorene	a,b	(lb/hr)	2.48E-04	2.46E-04	2.48E-04	2.46E-04	2.24E-04	1.65E-04	2.66E-04	2.67E-04	2.65E-04	2.47E-04	1.81E-04	2.98E-04	2.97E-04	2.76E-04	2.06E-04
Formaldehyde	a	(lb/hr)	2.41E-01	2.04E-01	2.41E-01	2.04E-01	1.86E-01	1.37E-01	2.33E-01	2.57E-01	2.20E-01	2.05E-01	1.50E-01	2.82E-01	2.46E-01	2.29E-01	1.71E-01
Hexane	a	(lb/hr)	8.82E-01	0.00E+00	8.82E-01	0.00E+00	0.00E+00	0.00E+00	3.27E-01	8.82E-01	0.00E+00	0.00E+00	0.00E+00	8.82E-01	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene	a,b	(lb/hr)	1.59E-04	1.58E-04	1.59E-04	1.58E-04	1.44E-04	1.06E-04	1.71E-04	1.71E-04	1.71E-04	1.59E-04	1.16E-04	1.92E-04	1.91E-04	1.78E-04	1.32E-04
Lead	a	(lb/hr)	2.45E-04	0.00E+00	2.45E-04	0.00E+00	0.00E+00	0.00E+00	9.09E-05	2.45E-04	0.00E+00	0.00E+00	0.00E+00	2.45E-04	0.00E+00	0.00E+00	0.00E+00
Manganese	a	(lb/hr)	1.86E-04	0.00E+00	1.86E-04	0.00E+00	0.00E+00	0.00E+00	6.91E-05	1.86E-04	0.00E+00	0.00E+00	0.00E+00	1.86E-04	0.00E+00	0.00E+00	0.00E+00
Mercury	a	(lb/hr)	1.27E-04	0.00E+00	1.27E-04	0.00E+00	0.00E+00	0.00E+00	4.73E-05	1.27E-04	0.00E+00	0.00E+00	0.00E+00	1.27E-04	0.00E+00	0.00E+00	0.00E+00
Methlyene Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Molybdenum		(lb/hr)	5.39E-04	0.00E+00	5.39E-04	0.00E+00	0.00E+00	0.00E+00	2.00E-04	5.39E-04	0.00E+00	0.00E+00	0.00E+00	5.39E-04	0.00E+00	0.00E+00	0.00E+00
Napthalene	a,c	(lb/hr)	2.71E-03	2.41E-03	2.71E-03	2.41E-03	2.20E-03	1.70E-03	2.71E-03	2.90E-03	2.60E-03	2.42E-03	1.87E-03	3.20E-03	2.90E-03	2.71E-03	2.13E-03
Nickel	a	(lb/hr)	1.03E-03	0.00E+00	1.03E-03	0.00E+00	0.00E+00	0.00E+00	3.82E-04	1.03E-03	0.00E+00	0.00E+00	0.00E+00	1.03E-03	0.00E+00	0.00E+00	0.00E+00
PAH	a,b	(lb/hr)	4.08E-03	4.08E-03	4.08E-03	4.08E-03	3.72E-03	2.80E-03	4.40E-03	4.40E-03	4.40E-03	4.09E-03	3.07E-03	4.91E-03	4.91E-03	4.58E-03	3.49E-03
Pentane		(lb/hr)	1.27E+00	0.00E+00	1.27E+00	0.00E+00	0.00E+00	0.00E+00	4.73E-01	1.27E+00	0.00E+00	0.00E+00	0.00E+00	1.27E+00	0.00E+00	0.00E+00	0.00E+00
Phenanathrene	a,b	(lb/hr)	1.50E-03	1.50E-03	1.50E-03	1.50E-03	1.36E-03	1.00E-03	1.61E-03	1.62E-03	1.61E-03	1.50E-03	1.10E-03	1.81E-03	1.80E-03	1.68E-03	1.25E-03
POM	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propane		(lb/hr)	7.84E-01	0.00E+00	7.84E-01	0.00E+00	0.00E+00	0.00E+00	2.91E-01	7.84E-01	0.00E+00	0.00E+00	0.00E+00	7.84E-01	0.00E+00	0.00E+00	0.00E+00
Propylene		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene Oxide	a	(lb/hr)	5.38E-02	5.38E-02	5.38E-02	5.38E-02	4.90E-02	3.61E-02	5.80E-02	5.80E-02	5.80E-02	5.40E-02	3.96E-02	6.48E-02	6.48E-02	6.04E-02	4.50E-02
Pyrene	a,b	(lb/hr)	4.42E-04	4.40E-04	4.42E-04	4.40E-04	4.00E-04	2.95E-04	4.75E-04	4.76E-04	4.74E-04	4.41E-04	3.23E-04	5.32E-04	5.29E-04	4.94E-04	3.68E-04
Selenium	a	(lb/hr)	1.18E-05	0.00E+00	1.18E-05	0.00E+00	0.00E+00	0.00E+00	4.36E-06	1.18E-05	0.00E+00	0.00E+00	0.00E+00	1.18E-05	0.00E+00	0.00E+00	0.00E+00
Sulfuric Acid		(lb/hr)	1.24E+00	1.24E+00	1.24E+00	1.24E+00	1.13E+00	8.30E-01	1.33E+00	1.33E+00	1.33E+00	1.24E+00	9.11E-01	1.49E+00	1.49E+00	1.39E+00	1.04E+00
Tetrachloroethylene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene	a	(lb/hr)	2.43E-01	2.41E-01	2.43E-01	2.41E-01	2.20E-01	1.62E-01	2.60E-01	2.61E-01	2.60E-01	2.42E-01	1.77E-01	2.92E-01	2.90E-01	2.71E-01	2.02E-01
Trichloroethylene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vanadium		(lb/hr)	1.13E-03	0.00E+00	1.13E-03	0.00E+00	0.00E+00	0.00E+00	4.18E-04	1.13E-03	0.00E+00	0.00E+00	0.00E+00	1.13E-03	0.00E+00	0.00E+00	0.00E+00
Vinyl Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vinylidene Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xylenes	a	(lb/hr)	1.19E-01	1.19E-01	1.19E-01	1.19E-01	1.08E-01	7.96E-02	1.28E-01	1.28E-01	1.28E-01	1.19E-01	8.73E-02	1.43E-01	1.43E-01	1.33E-01	9.93E-02
Zinc		(lb/hr)	1.42E-02	0.00E+00	1.42E-02	0.00E+00	0.00E+00	0.00E+00	5.27E-03	1.42E-02	0.00E+00	0.00E+00	0.00E+00	1.42E-02	0.00E+00	0.00E+00	0.00E+00

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
(Page 2 of 6)

Fuel			Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
Ambient Temp.		°F	90	90	90	90	51	51	51	-5	-5	-5
Turbine Load			BASE	BASE	85%	70%	BASE	85%	70%	100%	85%	70%
Inlet Air Cooling			On	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Heat Input-HHV		mmBtu/hr	1,757	1,698	1,504	1,303	1,894	1,662	1,436	2,145	1,867	1,606
1,3-Butadiene	a	(lb/hr)	2.81E-02	2.72E-02	2.41E-02	2.15E-02	3.03E-02	2.66E-02	2.37E-02	3.43E-02	2.99E-02	2.65E-02
1,1,1-Trichloroethane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,4-Dichlorobenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.87E-02	0.00E+00	0.00E+00	4.26E-02	0.00E+00	0.00E+00	4.77E-02
2-Methylnapthalene		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene	a,b	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene	a,b	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthene	a,b	(lb/hr)	2.39E-02	2.31E-02	2.05E-02	1.77E-02	2.58E-02	2.26E-02	1.95E-02	2.92E-02	2.54E-02	2.18E-02
Acenaphthylene	a,b	(lb/hr)	2.87E-04	2.77E-04	2.45E-04	2.13E-04	3.09E-04	2.71E-04	2.34E-04	3.50E-04	3.04E-04	2.62E-04
Acetaldehyde	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.95E-02	0.00E+00	0.00E+00	4.35E-02	0.00E+00	0.00E+00	4.87E-02
Acrolein	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ammonia		(lb/hr)	1.01E+01	9.84E+00	8.92E+00	8.09E+00	1.11E+01	9.89E+00	8.96E+00	1.23E+01	1.08E+01	9.74E+00
Anthracene	a,b	(lb/hr)	1.38E-03	1.34E-03	1.18E-03	1.02E-03	1.49E-03	1.31E-03	1.13E-03	1.69E-03	1.47E-03	1.26E-03
Arsenic	a	(lb/hr)	1.93E-02	1.87E-02	1.65E-02	1.43E-02	2.08E-02	1.83E-02	1.58E-02	2.36E-02	2.05E-02	1.77E-02
Barium		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene	a,b	(lb/hr)	4.54E-03	4.39E-03	3.89E-03	3.37E-03	4.90E-03	4.30E-03	3.71E-03	5.54E-03	4.83E-03	4.15E-03
Benzene	a	(lb/hr)	9.66E-02	9.34E-02	8.27E-02	7.17E-02	1.04E-01	9.14E-02	7.90E-02	1.18E-01	1.03E-01	8.83E-02
Benzo(a)pyrene	a,b	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(b)fluoranthene	a,b	(lb/hr)	1.68E-03	1.62E-03	1.43E-03	1.24E-03	1.81E-03	1.59E-03	1.37E-03	2.05E-03	1.78E-03	1.53E-03
Benzo(b,k)fluoranthene		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene	a,b	(lb/hr)	2.56E-03	2.47E-03	2.19E-03	1.90E-03	2.76E-03	2.42E-03	2.09E-03	3.12E-03	2.72E-03	2.34E-03
Benzo(k)fluoranthene	a,b	(lb/hr)	1.68E-03	1.62E-03	1.43E-03	1.24E-03	1.81E-03	1.59E-03	1.37E-03	2.05E-03	1.78E-03	1.53E-03
Beryllium	a	(lb/hr)	5.45E-04	5.26E-04	4.66E-04	4.04E-04	5.87E-04	5.15E-04	4.45E-04	6.65E-04	5.79E-04	4.98E-04
Butane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	a	(lb/hr)	8.43E-03	8.15E-03	7.22E-03	6.25E-03	9.09E-03	7.98E-03	6.89E-03	1.03E-02	8.96E-03	7.71E-03
Carbon Tetrachloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.99E-02	0.00E+00	0.00E+00	4.39E-02	0.00E+00	0.00E+00	4.91E-02
Chlorobenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.24E-02	0.00E+00	0.00E+00	3.58E-02	0.00E+00	0.00E+00	4.00E-02
Chloroform	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.32E-02	0.00E+00	0.00E+00	3.66E-02	0.00E+00	0.00E+00	4.10E-02
Chromium	a	(lb/hr)	1.93E-02	1.87E-02	1.65E-02	1.43E-02	2.08E-02	1.83E-02	1.58E-02	2.36E-02	2.05E-02	1.77E-02
Chrysene	a,b	(lb/hr)	2.70E-03	2.61E-03	2.31E-03	2.00E-03	2.91E-03	2.55E-03	2.20E-03	3.29E-03	2.86E-03	2.46E-03
Cobalt	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene	a,b	(lb/hr)	1.89E-03	1.83E-03	1.62E-03	1.40E-03	2.04E-03	1.79E-03	1.55E-03	2.31E-03	2.01E-03	1.73E-03
Dichlorobenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylene Dichloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	2.63E-02	0.00E+00	0.00E+00	2.90E-02	0.00E+00	0.00E+00	3.24E-02
Fluoranthene	a,b	(lb/hr)	5.48E-03	5.30E-03	4.69E-03	4.07E-03	5.91E-03	5.19E-03	4.48E-03	6.69E-03	5.82E-03	5.01E-03
Fluorene	a,b	(lb/hr)	5.06E-03	4.89E-03	4.33E-03	3.75E-03	5.46E-03	4.79E-03	4.14E-03	6.18E-03	5.38E-03	4.63E-03
Formaldehyde	a	(lb/hr)	4.92E-01	4.75E-01	4.21E-01	3.65E-01	5.30E-01	4.65E-01	4.02E-01	6.01E-01	5.23E-01	4.50E-01
Hexane	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene	a,b	(lb/hr)	2.42E-03	2.34E-03	2.07E-03	1.80E-03	2.61E-03	2.29E-03	1.98E-03	2.96E-03	2.58E-03	2.22E-03
Lead	a	(lb/hr)	2.46E-02	2.38E-02	2.11E-02	1.82E-02	2.65E-02	2.33E-02	2.01E-02	3.00E-02	2.61E-02	2.25E-02
Manganese	a	(lb/hr)	1.39E+00	1.34E+00	1.19E+00	1.03E+00	1.50E+00	1.31E+00	1.13E+00	1.69E+00	1.47E+00	1.27E+00
Mercury	a	(lb/hr)	2.11E-03	2.04E-03	1.80E-03	1.56E-03	2.27E-03	1.99E-03	1.72E-03	2.57E-03	2.24E-03	1.93E-03
Methlyene Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	2.78E-02	0.00E+00	0.00E+00	3.06E-02	0.00E+00	0.00E+00	3.42E-02
Molybdenum		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Napthalene	a,c	(lb/hr)	6.15E-02	5.94E-02	5.26E-02	4.59E-02	6.63E-02	5.82E-02	5.05E-02	7.51E-02	6.53E-02	5.65E-02
Nickel	a	(lb/hr)	8.08E-03	7.81E-03	6.92E-03	2.11E-02	8.71E-03	7.65E-03	2.33E-02	9.87E-03	8.59E-03	2.60E-02
PAH	a,b	(lb/hr)	7.03E-02	6.79E-02	6.02E-02	5.25E-02	7.58E-02	6.65E-02	5.79E-02	8.58E-02	7.47E-02	6.47E-02
Pentane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phenanathrene	a,b	(lb/hr)	1.19E-02	1.15E-02	1.02E-02	8.82E-03	1.28E-02	1.12E-02	9.72E-03	1.45E-02	1.26E-02	1.09E-02
POM	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propane		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene Oxide	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pyrene	a,b	(lb/hr)	4.81E-03	4.65E-03	4.12E-03	3.57E-03	5.19E-03	4.55E-03	3.93E-03	5.88E-03	5.11E-03	4.40E-03
Selenium	a	(lb/hr)	4.39E-02	4.25E-02	3.76E-02	3.75E-02	4.74E-02	4.16E-02	4.14E-02	5.36E-02	4.67E-02	4.63E-02
Sulfuric Acid		(lb/hr)	8.20E-01	7.93E-01	7.02E-01	6.08E-01	8.84E-01	7.76E-01	6.70E-01	1.00E+00	8.72E-01	7.50E-01
Tetrachloroethylene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	4.22E-02	0.00E+00	0.00E+00	4.65E-02	0.00E+00	0.00E+00	5.20E-02
Toluene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Trichloroethylene	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	3.58E-02	0.00E+00	0.00E+00	3.95E-02	0.00E+00	0.00E+00	4.42E-02
Vanadium		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vinyl Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	6.87E-02	0.00E+00	0.00E+00	7.57E-02	0.00E+00	0.00E+00	8.46E-02
Vinylidene Chloride	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	2.63E-02	0.00E+00	0.00E+00	2.90E-02	0.00E+00	0.00E+00	3.24E-02
Xylenes	a	(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc		(lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
(Page 3 of 6)

Fuel			**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**	**Methane**
Ambient Temp.		°F	90	90	90	90	90	90	51	51	51	51	51	-5	-5	-5	-5
Turbine Load			BASE	BASE	BASE	BASE	80%	60%	BASE	BASE	BASE	80%	60%	1	1	80%	60%
Inlet Air Cooling			On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Heat Input-HHV		mmBtu/hr	1855	1855	1855	1855	1689	1243	1998	1998	1998	1861	1364	2234	2234	2083	1551
Duct Burner Operation			On	Off	On	Off	Off	Off	On	On	Off	Off	Off	On	Off	Off	Off
Duct Burner Rate (HHV)	Note	mmBtu/hr	500	0	500	0	0	0	185	500	0	0	0	500	0	0	0
1,3-Butadiene	a	(g/s)	1.01E-04	1.01E-04	1.01E-04	1.01E-04	9.15E-05	6.74E-05	1.08E-04	1.08E-04	1.08E-04	1.01E-04	7.39E-05	1.21E-04	1.21E-04	1.13E-04	8.41E-05
1,1,1-Trichloroethane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,4-Dichlorobenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2-Methylnapthalene		(g/s)	1.48E-06	0.00E+00	1.48E-06	0.00E+00	0.00E+00	0.00E+00	5.50E-07	1.48E-06	0.00E+00	0.00E+00	0.00E+00	1.48E-06	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene	a,b	(g/s)	1.11E-07	0.00E+00	1.11E-07	0.00E+00	0.00E+00	0.00E+00	4.12E-08	1.11E-07	0.00E+00	0.00E+00	0.00E+00	1.11E-07	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene	a,b	(g/s)	9.88E-07	0.00E+00	9.88E-07	0.00E+00	0.00E+00	0.00E+00	3.66E-07	9.88E-07	0.00E+00	0.00E+00	0.00E+00	9.88E-07	0.00E+00	0.00E+00	0.00E+00
Acenaphthene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Acenaphthylene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Acetaldehyde	a	(g/s)	9.35E-03	9.35E-03	9.35E-03	9.35E-03	8.51E-03	6.97E-03	1.01E-02	1.01E-02	1.01E-02	9.38E-03	7.65E-03	1.13E-02	1.13E-02	1.05E-02	8.70E-03
Acrolein	a	(g/s)	1.50E-03	1.50E-03	1.50E-03	1.50E-03	1.36E-03	1.30E-03	1.61E-03	1.61E-03	1.61E-03	1.50E-03	1.43E-03	1.80E-03	1.80E-03	1.68E-03	1.62E-03
Ammonia		(g/s)	1.25E+00	1.25E+00	1.22E+00	1.22E+00	1.07E+00	9.15E-01	1.37E+00	1.37E+00	1.37E+00	1.18E+00	1.01E+00	1.50E+00	1.50E+00	1.29E+00	1.10E+00
Anthracene	a,b	(g/s)	2.67E-05	2.66E-05	2.67E-05	2.66E-05	2.42E-05	1.78E-05	2.87E-05	2.88E-05	2.87E-05	2.67E-05	1.96E-05	3.22E-05	3.20E-05	2.99E-05	2.22E-05
Arsenic	a	(g/s)	1.24E-05	0.00E+00	1.24E-05	0.00E+00	0.00E+00	0.00E+00	4.58E-06	1.24E-05	0.00E+00	0.00E+00	0.00E+00	1.24E-05	0.00E+00	0.00E+00	0.00E+00
Barium		(g/s)	2.72E-04	0.00E+00	2.72E-04	0.00E+00	0.00E+00	0.00E+00	1.01E-04	2.72E-04	0.00E+00	0.00E+00	0.00E+00	2.72E-04	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Benzene	a	(g/s)	2.93E-03	2.81E-03	2.93E-03	2.81E-03	2.55E-03	1.61E-02	3.07E-03	3.15E-03	3.02E-03	2.81E-03	1.77E-02	3.51E-03	3.38E-03	3.15E-03	2.01E-02
Benzo(a)pyrene	a,b	(g/s)	1.34E-05	1.33E-05	1.34E-05	1.33E-05	1.21E-05	8.91E-06	1.44E-05	1.44E-05	1.43E-05	1.33E-05	9.78E-06	1.61E-05	1.60E-05	1.49E-05	1.11E-05
Benzo(b)fluoranthene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Benzo(b,k)fluoranthene		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene	a,b	(g/s)	1.34E-05	1.33E-05	1.34E-05	1.33E-05	1.21E-05	8.91E-06	1.44E-05	1.44E-05	1.43E-05	1.33E-05	9.78E-06	1.61E-05	1.60E-05	1.49E-05	1.11E-05
Benzo(k)fluoranthene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Beryllium	a	(g/s)	7.41E-07	0.00E+00	7.41E-07	0.00E+00	0.00E+00	0.00E+00	2.75E-07	7.41E-07	0.00E+00	0.00E+00	0.00E+00	7.41E-07	0.00E+00	0.00E+00	0.00E+00
Butane		(g/s)	1.30E-01	0.00E+00	1.30E-01	0.00E+00	0.00E+00	0.00E+00	4.81E-02	1.30E-01	0.00E+00	0.00E+00	0.00E+00	1.30E-01	0.00E+00	0.00E+00	0.00E+00
Cadmium	a	(g/s)	6.79E-05	0.00E+00	6.79E-05	0.00E+00	0.00E+00	0.00E+00	2.52E-05	6.79E-05	0.00E+00	0.00E+00	0.00E+00	6.79E-05	0.00E+00	0.00E+00	0.00E+00
Carbon Tetrachloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorobenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chloroform	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium	a	(g/s)	8.65E-05	0.00E+00	8.65E-05	0.00E+00	0.00E+00	0.00E+00	3.21E-05	8.65E-05	0.00E+00	0.00E+00	0.00E+00	8.65E-05	0.00E+00	0.00E+00	0.00E+00
Chrysene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Cobalt	a	(g/s)	5.19E-06	0.00E+00	5.19E-06	0.00E+00	0.00E+00	0.00E+00	1.92E-06	5.19E-06	0.00E+00	0.00E+00	0.00E+00	5.19E-06	0.00E+00	0.00E+00	0.00E+00
Copper		(g/s)	5.25E-05	0.00E+00	5.25E-05	0.00E+00	0.00E+00	0.00E+00	1.95E-05	5.25E-05	0.00E+00	0.00E+00	0.00E+00	5.25E-05	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene	a,b	(g/s)	1.34E-05	1.33E-05	1.34E-05	1.33E-05	1.21E-05	8.91E-06	1.44E-05	1.44E-05	1.43E-05	1.33E-05	9.78E-06	1.61E-05	1.60E-05	1.49E-05	1.11E-05
Dichlorobenzene	a	(g/s)	7.41E-05	0.00E+00	7.41E-05	0.00E+00	0.00E+00	0.00E+00	2.75E-05	7.41E-05	0.00E+00	0.00E+00	0.00E+00	7.41E-05	0.00E+00	0.00E+00	0.00E+00
Ethane		(g/s)	1.91E-01	0.00E+00	1.91E-01	0.00E+00	0.00E+00	0.00E+00	7.10E-02	1.91E-01	0.00E+00	0.00E+00	0.00E+00	1.91E-01	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	a	(g/s)	7.48E-03	7.48E-03	7.48E-03	7.48E-03	6.81E-03	5.01E-03	8.06E-03	8.06E-03	8.06E-03	7.50E-03	5.50E-03	9.01E-03	9.01E-03	8.40E-03	6.26E-03
Ethylene Dichloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoranthene	a,b	(g/s)	3.34E-05	3.33E-05	3.34E-05	3.33E-05	3.03E-05	2.23E-05	3.59E-05	3.60E-05	3.58E-05	3.34E-05	2.44E-05	4.02E-05	4.00E-05	3.73E-05	2.78E-05
Fluorene	a,b	(g/s)	3.12E-05	3.10E-05	3.12E-05	3.10E-05	2.83E-05	2.08E-05	3.35E-05	3.36E-05	3.34E-05	3.11E-05	2.28E-05	3.75E-05	3.74E-05	3.48E-05	2.60E-05
Formaldehyde	a	(g/s)	3.03E-02	2.57E-02	3.03E-02	2.57E-02	2.34E-02	1.72E-02	2.94E-02	3.23E-02	2.77E-02	2.58E-02	1.89E-02	3.56E-02	3.10E-02	2.89E-02	2.15E-02
Hexane	a	(g/s)	1.11E-01	0.00E+00	1.11E-01	0.00E+00	0.00E+00	0.00E+00	4.12E-02	1.11E-01	0.00E+00	0.00E+00	0.00E+00	1.11E-01	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene	a,b	(g/s)	2.01E-05	2.00E-05	2.01E-05	2.00E-05	1.82E-05	1.34E-05	2.15E-05	2.16E-05	2.15E-05	2.00E-05	1.47E-05	2.41E-05	2.40E-05	2.24E-05	1.67E-05
Lead	a	(g/s)	3.09E-05	0.00E+00	3.09E-05	0.00E+00	0.00E+00	0.00E+00	1.14E-05	3.09E-05	0.00E+00	0.00E+00	0.00E+00	3.09E-05	0.00E+00	0.00E+00	0.00E+00
Manganese	a	(g/s)	2.35E-05	0.00E+00	2.35E-05	0.00E+00	0.00E+00	0.00E+00	8.70E-06	2.35E-05	0.00E+00	0.00E+00	0.00E+00	2.35E-05	0.00E+00	0.00E+00	0.00E+00
Mercury	a	(g/s)	1.61E-05	0.00E+00	1.61E-05	0.00E+00	0.00E+00	0.00E+00	5.95E-06	1.61E-05	0.00E+00	0.00E+00	0.00E+00	1.61E-05	0.00E+00	0.00E+00	0.00E+00
Methlyene Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Molybdenum		(g/s)	6.79E-05	0.00E+00	6.79E-05	0.00E+00	0.00E+00	0.00E+00	2.52E-05	6.79E-05	0.00E+00	0.00E+00	0.00E+00	6.79E-05	0.00E+00	0.00E+00	0.00E+00
Napthalene	a,c	(g/s)	3.42E-04	3.04E-04	3.42E-04	3.04E-04	2.77E-04	2.15E-04	3.41E-04	3.65E-04	3.27E-04	3.05E-04	2.35E-04	4.04E-04	3.66E-04	3.41E-04	2.68E-04
Nickel	a	(g/s)	1.30E-04	0.00E+00	1.30E-04	0.00E+00	0.00E+00	0.00E+00	4.81E-05	1.30E-04	0.00E+00	0.00E+00	0.00E+00	1.30E-04	0.00E+00	0.00E+00	0.00E+00
PAH	a,b	(g/s)	5.14E-04	5.14E-04	5.14E-04	5.14E-04	4.68E-04	3.52E-04	5.54E-04	5.54E-04	5.54E-04	5.16E-04	3.87E-04	6.19E-04	6.19E-04	5.77E-04	4.40E-04
Pentane		(g/s)	1.61E-01	0.00E+00	1.61E-01	0.00E+00	0.00E+00	0.00E+00	5.95E-02	1.61E-01	0.00E+00	0.00E+00	0.00E+00	1.61E-01	0.00E+00	0.00E+00	0.00E+00
Phenanathrene	a,b	(g/s)	1.89E-04	1.88E-04	1.89E-04	1.88E-04	1.72E-04	1.26E-04	2.03E-04	2.04E-04	2.03E-04	1.89E-04	1.39E-04	2.28E-04	2.27E-04	2.12E-04	1.58E-04
POM	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propane		(g/s)	9.88E-02	0.00E+00	9.88E-02	0.00E+00	0.00E+00	0.00E+00	3.66E-02	9.88E-02	0.00E+00	0.00E+00	0.00E+00	9.88E-02	0.00E+00	0.00E+00	0.00E+00
Propylene		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene Oxide	a	(g/s)	6.78E-03	6.78E-03	6.78E-03	6.78E-03	6.17E-03	4.54E-03	7.30E-03	7.30E-03	7.30E-03	6.80E-03	4.98E-03	8.16E-03	8.16E-03	7.61E-03	5.67E-03
Pyrene	a,b	(g/s)	5.57E-05	5.54E-05	5.57E-05	5.54E-05	5.05E-05	3.71E-05	5.98E-05	6.00E-05	5.97E-05	5.56E-05	4.07E-05	6.70E-05	6.67E-05	6.22E-05	4.63E-05
Selenium	a	(g/s)	1.48E-06	0.00E+00	1.48E-06	0.00E+00	0.00E+00	0.00E+00	5.50E-07	1.48E-06	0.00E+00	0.00E+00	0.00E+00	1.48E-06	0.00E+00	0.00E+00	0.00E+00
Sulfuric Acid		(g/s)	1.56E-01	1.56E-01	1.56E-01	1.56E-01	1.42E-01	1.05E-01	1.68E-01	1.68E-01	1.68E-01	1.57E-01	1.15E-01	1.88E-01	1.88E-01	1.75E-01	1.31E-01
Tetrachloroethylene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene	a	(g/s)	3.06E-02	3.04E-02	3.06E-02	3.04E-02	2.77E-02	2.04E-02	3.28E-02	3.29E-02	3.27E-02	3.05E-02	2.23E-02	3.68E-02	3.66E-02	3.41E-02	2.54E-02
Trichloroethylene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vanadium		(g/s)	1.42E-04	0.00E+00	1.42E-04	0.00E+00	0.00E+00	0.00E+00	5.27E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	1.42E-04	0.00E+00	0.00E+00	0.00E+00
Vinyl Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vinylidene Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xylenes	a	(g/s)	1.50E-02	1.50E-02	1.50E-02	1.50E-02	1.36E-02	1.00E-02	1.61E-02	1.61E-02	1.61E-02	1.50E-02	1.10E-02	1.80E-02	1.80E-02	1.68E-02	1.25E-02
Zinc		(g/s)	1.79E-03	0.00E+00	1.79E-03	0.00E+00	0.00E+00	0.00E+00	6.64E-04	1.79E-03	0.00E+00	0.00E+00	0.00E+00	1.79E-03	0.00E+00	0.00E+00	0.00E+00

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
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Fuel			Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
Ambient Temp.		°F	90	90	90	90	51	51	51	-5	-5	-5
Turbine Load			BASE	BASE	85%	70%	BASE	85%	70%	1	85%	70%
Inlet Air Cooling			On	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Heat Input-HHV		mmBtu/hr	1,757	1,698	1,504	1,303	1,894	1,662	1,436	2,145	1,867	1,606
1,3-Butadiene	a	(g/s)	3.54E-03	3.42E-03	3.03E-03	2.71E-03	3.82E-03	3.35E-03	2.99E-03	4.32E-03	3.76E-03	3.34E-03
1,1,1-Trichloroethane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,4-Dichlorobenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	4.88E-03	0.00E+00	0.00E+00	5.37E-03	0.00E+00	0.00E+00	6.01E-03
2-Methylnapthalene		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene	a,b	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene	a,b	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthene	a,b	(g/s)	3.01E-03	2.91E-03	2.58E-03	2.23E-03	3.25E-03	2.85E-03	2.46E-03	3.68E-03	3.20E-03	2.75E-03
Acenaphthylene	a,b	(g/s)	3.61E-05	3.49E-05	3.09E-05	2.68E-05	3.89E-05	3.42E-05	2.95E-05	4.41E-05	3.84E-05	3.30E-05
Acetaldehyde	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	4.97E-03	0.00E+00	0.00E+00	5.48E-03	0.00E+00	0.00E+00	6.13E-03
Acrolein	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ammonia		(g/s)	1.27E+00	1.24E+00	1.12E+00	1.02E+00	1.39E+00	1.25E+00	1.13E+00	1.55E+00	1.36E+00	1.23E+00
Anthracene	a,b	(g/s)	1.74E-04	1.68E-04	1.49E-04	1.29E-04	1.88E-04	1.65E-04	1.42E-04	2.13E-04	1.85E-04	1.59E-04
Arsenic	a	(g/s)	2.44E-03	2.35E-03	2.08E-03	1.81E-03	2.63E-03	2.30E-03	1.99E-03	2.97E-03	2.59E-03	2.23E-03
Barium		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene	a,b	(g/s)	5.72E-04	5.53E-04	4.90E-04	4.24E-04	6.17E-04	5.41E-04	4.68E-04	6.99E-04	6.08E-04	5.23E-04
Benzene	a	(g/s)	1.22E-02	1.18E-02	1.04E-02	9.03E-03	1.31E-02	1.15E-02	9.95E-03	1.49E-02	1.29E-02	1.11E-02
Benzo(a)pyrene	a,b	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(b)fluoranthene	a,b	(g/s)	2.11E-04	2.04E-04	1.81E-04	1.57E-04	2.28E-04	2.00E-04	1.73E-04	2.58E-04	2.24E-04	1.93E-04
Benzo(b,k)fluoranthene		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene	a,b	(g/s)	3.23E-04	3.12E-04	2.76E-04	2.39E-04	3.48E-04	3.05E-04	2.64E-04	3.94E-04	3.43E-04	2.95E-04
Benzo(k)fluoranthene	a,b	(g/s)	2.11E-04	2.04E-04	1.81E-04	1.57E-04	2.28E-04	2.00E-04	1.73E-04	2.58E-04	2.24E-04	1.93E-04
Beryllium	a	(g/s)	6.86E-05	6.63E-05	5.87E-05	5.09E-05	7.40E-05	6.49E-05	5.61E-05	8.38E-05	7.29E-05	6.27E-05
Butane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	a	(g/s)	1.06E-03	1.03E-03	9.10E-04	7.88E-04	1.15E-03	1.01E-03	8.68E-04	1.30E-03	1.13E-03	9.71E-04
Carbon Tetrachloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	5.02E-03	0.00E+00	0.00E+00	5.54E-03	0.00E+00	0.00E+00	6.19E-03
Chlorobenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	4.09E-03	0.00E+00	0.00E+00	4.51E-03	0.00E+00	0.00E+00	5.04E-03
Chloroform	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	4.19E-03	0.00E+00	0.00E+00	4.61E-03	0.00E+00	0.00E+00	5.16E-03
Chromium	a	(g/s)	2.44E-03	2.35E-03	2.08E-03	1.81E-03	2.63E-03	2.30E-03	1.99E-03	2.97E-03	2.59E-03	2.23E-03
Chrysene	a,b	(g/s)	3.40E-04	3.28E-04	2.91E-04	2.52E-04	3.66E-04	3.21E-04	2.78E-04	4.15E-04	3.61E-04	3.10E-04
Cobalt	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene	a,b	(g/s)	2.38E-04	2.30E-04	2.04E-04	1.77E-04	2.57E-04	2.25E-04	1.95E-04	2.91E-04	2.53E-04	2.18E-04
Dichlorobenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylene Dichloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	3.32E-03	0.00E+00	0.00E+00	3.65E-03	0.00E+00	0.00E+00	4.09E-03
Fluoranthene	a,b	(g/s)	6.91E-04	6.67E-04	5.91E-04	5.12E-04	7.45E-04	6.53E-04	5.64E-04	8.43E-04	7.34E-04	6.31E-04
Fluorene	a,b	(g/s)	6.38E-04	6.16E-04	5.46E-04	4.73E-04	6.88E-04	6.03E-04	5.21E-04	7.79E-04	6.78E-04	5.83E-04
Formaldehyde	a	(g/s)	6.20E-02	5.99E-02	5.31E-02	4.60E-02	6.68E-02	5.86E-02	5.07E-02	7.57E-02	6.59E-02	5.67E-02
Hexane	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene	a,b	(g/s)	3.05E-04	2.95E-04	2.61E-04	2.26E-04	3.29E-04	2.89E-04	2.50E-04	3.73E-04	3.25E-04	2.79E-04
Lead	a	(g/s)	3.10E-03	3.00E-03	2.65E-03	2.30E-03	3.34E-03	2.93E-03	2.53E-03	3.78E-03	3.29E-03	2.83E-03
Manganese	a	(g/s)	1.75E-01	1.69E-01	1.50E-01	1.30E-01	1.89E-01	1.65E-01	1.43E-01	2.14E-01	1.86E-01	1.60E-01
Mercury	a	(g/s)	2.66E-04	2.57E-04	2.27E-04	1.97E-04	2.86E-04	2.51E-04	2.17E-04	3.24E-04	2.82E-04	2.43E-04
Methlyene Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	3.50E-03	0.00E+00	0.00E+00	3.85E-03	0.00E+00	0.00E+00	4.31E-03
Molybdenum		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Napthalene	a,c	(g/s)	7.75E-03	7.49E-03	6.63E-03	5.78E-03	8.35E-03	7.33E-03	6.37E-03	9.46E-03	8.23E-03	7.12E-03
Nickel	a	(g/s)	1.02E-03	9.84E-04	8.72E-04	2.66E-03	1.10E-03	9.63E-04	2.93E-03	1.24E-03	1.08E-03	3.28E-03
PAH	a,b	(g/s)	8.86E-03	8.56E-03	7.58E-03	6.62E-03	9.55E-03	8.38E-03	7.29E-03	1.08E-02	9.41E-03	8.15E-03
Pentane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phenanathrene	a,b	(g/s)	1.50E-03	1.45E-03	1.28E-03	1.11E-03	1.62E-03	1.42E-03	1.22E-03	1.83E-03	1.59E-03	1.37E-03
POM	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propane		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Propylene Oxide	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pyrene	a,b	(g/s)	6.06E-04	5.86E-04	5.19E-04	4.50E-04	6.54E-04	5.74E-04	4.96E-04	7.40E-04	6.44E-04	5.54E-04
Selenium	a	(g/s)	5.53E-03	5.35E-03	4.74E-03	4.73E-03	5.97E-03	5.24E-03	5.21E-03	6.76E-03	5.88E-03	5.83E-03
Sulfuric Acid		(g/s)	1.03E-01	9.99E-02	8.85E-02	7.67E-02	1.11E-01	9.77E-02	8.45E-02	1.26E-01	1.10E-01	9.45E-02
Tetrachloroethylene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	5.32E-03	0.00E+00	0.00E+00	5.86E-03	0.00E+00	0.00E+00	6.56E-03
Toluene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Trichloroethylene	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	4.51E-03	0.00E+00	0.00E+00	4.98E-03	0.00E+00	0.00E+00	5.56E-03
Vanadium		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vinyl Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	8.65E-03	0.00E+00	0.00E+00	9.54E-03	0.00E+00	0.00E+00	1.07E-02
Vinylidene Chloride	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	3.32E-03	0.00E+00	0.00E+00	3.65E-03	0.00E+00	0.00E+00	4.09E-03
Xylenes	a	(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc		(g/s)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
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Combined Cycle Unit Potential HAP Emissions

Annual Operating Scenario			Gas Only	Gas/Oil	Single CTG/DB		2 x CTG/DB		**Facility-Wide 2CTG/DB and Aux. Equip.**
Gas Fired Operation		hr/yr	8,760	8,040	Worst Case Annual Emissions (scientific)	Worst Case Annual Emissions (decimal)	Worst Case Annual Emissions (scientific)	Worst Case Annual Emissions (decimal)	**(tons/yr)**
Oil-Fired Operation (w/o duct burner)		hr/yr	0	720					
Gas-Fired Operation (w/ duct burner)		hr/yr	2,628	2,628					
Gas-Fired Operation (w/o duct burner)	Note	hr/yr	6,132	5,412					
1,3-Butadiene	a	(tons/yr)	4.21E-03	1.62E-02	1.62E-02	0.016216	3.24E-02	0.032432	**3.26E-02**
1,1,1-Trichloroethane		(tons/yr)	0.00E+00	0.00E+00	0.00E+00	0.000000	0.00E+00	0.000000	**0.00E+00**
1,4-Dichlorobenzene	a	(tons/yr)	0.00E+00	1.72E-02	1.72E-02	0.017171	3.43E-02	0.034343	**3.43E-02**
2-Methylnapthalene		(tons/yr)	1.55E-05	1.55E-05	1.55E-05	0.000015	3.09E-05	0.000031	**3.31E-05**
3-Methylchloranthrene	a,b	(tons/yr)	1.16E-06	1.16E-06	1.16E-06	0.000001	2.32E-06	0.000002	**2.48E-06**
7,12-Dimethylbenz(a)anthracene	a,b	(tons/yr)	1.03E-05	1.03E-05	1.03E-05	0.000010	2.06E-05	0.000021	**2.21E-05**
Acenaphthene	a,b	(tons/yr)	8.36E-04	1.13E-02	1.13E-02	0.011270	2.25E-02	0.022541	**2.25E-02**
Acenaphthylene	a,b	(tons/yr)	8.36E-04	8.93E-04	8.93E-04	0.000893	1.79E-03	0.001787	**1.81E-03**
Acetaldehyde	a	(tons/yr)	3.91E-01	3.77E-01	3.91E-01	0.391314	7.83E-01	0.782628	**7.86E-01**
Acrolein	a	(tons/yr)	6.26E-02	5.75E-02	6.26E-02	0.062610	1.25E-01	0.125220	**1.26E-01**
Ammonia		(tons/yr)	5.23E+01	5.24E+01	5.24E+01	52.395440	1.05E+02	104.790880	**1.05E+02**
Anthracene	a,b	(tons/yr)	1.11E-03	1.63E-03	1.63E-03	0.001631	3.26E-03	0.003261	**3.27E-03**
Arsenic	a	(tons/yr)	1.29E-04	8.62E-03	8.62E-03	0.008623	1.72E-02	0.017246	**1.73E-02**
Barium		(tons/yr)	2.83E-03	2.83E-03	2.83E-03	0.002834	5.67E-03	0.005668	**6.07E-03**
Benz(a)anthracene	a,b	(tons/yr)	8.36E-04	2.76E-03	2.76E-03	0.002764	5.53E-03	0.005527	**5.53E-03**
Benzene	a	(tons/yr)	5.27E-01	5.11E-01	5.27E-01	0.526529	1.05E+00	1.053057	**1.06E+00**
Benzo(a)pyrene	a,b	(tons/yr)	5.57E-04	5.12E-04	5.57E-04	0.000557	1.11E-03	0.001115	**1.12E-03**
Benzo(b)fluoranthene	a,b	(tons/yr)	8.36E-04	1.50E-03	1.50E-03	0.001504	3.01E-03	0.003008	**3.01E-03**
Benzo(b,k)fluoranthene		(tons/yr)	0.00E+00	0.00E+00	0.00E+00	0.000000	0.00E+00	0.000000	**0.00E+00**
Benzo(g,h,i)perylene	a,b	(tons/yr)	5.57E-04	1.64E-03	1.64E-03	0.001637	3.27E-03	0.003273	**3.28E-03**
Benzo(k)fluoranthene	a,b	(tons/yr)	8.36E-04	1.50E-03	1.50E-03	0.001504	3.01E-03	0.003008	**3.01E-03**
Beryllium	a	(tons/yr)	7.73E-06	2.47E-04	2.47E-04	0.000247	4.94E-04	0.000494	**4.95E-04**
Butane		(tons/yr)	1.35E+00	1.35E+00	1.35E+00	1.352647	2.71E+00	2.705294	**2.90E+00**
Cadmium	a	(tons/yr)	7.09E-04	4.42E-03	4.42E-03	0.004415	8.83E-03	0.008830	**8.93E-03**
Carbon Tetrachloride	a	(tons/yr)	0.00E+00	1.77E-02	1.77E-02	0.017692	3.54E-02	0.035383	**3.54E-02**
Chlorobenzene	a	(tons/yr)	0.00E+00	1.44E-02	1.44E-02	0.014396	2.88E-02	0.028792	**2.88E-02**
Chloroform	a	(tons/yr)	0.00E+00	1.47E-02	1.47E-02	0.014743	2.95E-02	0.029486	**2.95E-02**
Chromium	a	(tons/yr)	9.02E-04	9.40E-03	9.40E-03	0.009396	1.88E-02	0.018792	**1.89E-02**
Chrysene	a,b	(tons/yr)	8.36E-04	1.95E-03	1.95E-03	0.001952	3.90E-03	0.003904	**3.91E-03**
Cobalt	a	(tons/yr)	5.41E-05	5.41E-05	5.41E-05	0.000054	1.08E-04	0.000108	**1.16E-04**
Copper		(tons/yr)	5.48E-04	5.48E-04	5.48E-04	0.000548	1.10E-03	0.001095	**1.17E-03**
Dibenzo(a,h)anthracene	a,b	(tons/yr)	5.57E-04	1.34E-03	1.34E-03	0.001343	2.69E-03	0.002686	**2.69E-03**
Dichlorobenzene	a	(tons/yr)	7.73E-04	7.73E-04	7.73E-04	0.000773	1.55E-03	0.001546	**1.66E-03**
Ethane		(tons/yr)	2.00E+00	2.00E+00	2.00E+00	1.996765	3.99E+00	3.993529	**4.28E+00**
Ethylbenzene	a	(tons/yr)	3.13E-01	2.87E-01	3.13E-01	0.313051	6.26E-01	0.626102	**6.26E-01**
Ethylene Dichloride	a	(tons/yr)	0.00E+00	1.17E-02	1.17E-02	0.011679	2.34E-02	0.023358	**2.34E-02**
Fluoranthene	a,b	(tons/yr)	1.39E-03	3.69E-03	3.69E-03	0.003688	7.38E-03	0.007377	**7.41E-03**
Fluorene	a,b	(tons/yr)	1.30E-03	3.42E-03	3.42E-03	0.003419	6.84E-03	0.006838	**6.97E-03**
Formaldehyde	a	(tons/yr)	1.12E+00	1.25E+00	1.25E+00	1.252190	2.50E+00	2.504380	**2.52E+00**
Hexane	a	(tons/yr)	1.16E+00	1.16E+00	1.16E+00	1.159412	2.32E+00	2.318824	**2.48E+00**
Indeno(1,2,3-cd)pyrene	a,b	(tons/yr)	8.36E-04	1.83E-03	1.83E-03	0.001833	3.67E-03	0.003665	**3.67E-03**
Lead	a	(tons/yr)	3.22E-04	1.11E-02	1.11E-02	0.011133	2.23E-02	0.022266	**2.23E-02**
Manganese	a	(tons/yr)	2.45E-04	6.10E-01	6.10E-01	0.610283	1.22E+00	1.220566	**1.22E+00**
Mercury	a	(tons/yr)	1.67E-04	1.09E-03	1.09E-03	0.001094	2.19E-03	0.002188	**2.21E-03**
Methlyene Chloride	a	(tons/yr)	0.00E+00	1.23E-02	1.23E-02	0.012315	2.46E-02	0.024630	**2.46E-02**
Molybdenum		(tons/yr)	7.09E-04	7.09E-04	7.09E-04	0.000709	1.42E-03	0.001417	**1.52E-03**
Napthalene	a,c	(tons/yr)	1.31E-02	3.91E-02	3.91E-02	0.039092	7.82E-02	0.078185	**7.86E-02**
Nickel	a	(tons/yr)	1.35E-03	1.07E-02	1.07E-02	0.010719	2.14E-02	0.021438	**2.16E-02**
PAH	a,b	(tons/yr)	2.15E-02	5.06E-02	5.06E-02	0.050641	1.01E-01	0.101283	**1.01E-01**
Pentane		(tons/yr)	1.67E+00	1.67E+00	1.67E+00	1.674706	3.35E+00	3.349412	**3.59E+00**
Phenanathrene	a,b	(tons/yr)	7.90E-03	1.25E-02	1.25E-02	0.012475	2.49E-02	0.024949	**2.51E-02**
POM	a	(tons/yr)	0.00E+00	0.00E+00	0.00E+00	0.000000	0.00E+00	0.000000	**0.00E+00**
Propane		(tons/yr)	1.03E+00	1.03E+00	1.03E+00	1.030588	2.06E+00	2.061176	**2.21E+00**
Propylene		(tons/yr)	0.00E+00	0.00E+00	0.00E+00	0.000000	0.00E+00	0.000000	**1.14E-02**
Propylene Oxide	a	(tons/yr)	2.84E-01	2.60E-01	2.84E-01	0.283702	5.67E-01	0.567405	**5.67E-01**
Pyrene	a,b	(tons/yr)	2.32E-03	4.25E-03	4.25E-03	0.004247	8.49E-03	0.008495	**8.52E-03**
Selenium	a	(tons/yr)	1.55E-05	1.93E-02	1.93E-02	0.019320	3.86E-02	0.038641	**3.86E-02**
Sulfuric Acid		(tons/yr)	6.53E+00	6.36E+00	6.53E+00	6.531507	1.31E+01	13.063013	**1.31E+01**
Tetrachloroethylene	a	(tons/yr)	0.00E+00	1.87E-02	1.87E-02	0.018732	3.75E-02	0.037465	**3.75E-02**
Toluene	a	(tons/yr)	1.27E+00	1.17E+00	1.27E+00	1.273960	2.55E+00	2.547919	**2.55E+00**
Trichloroethylene	a	(tons/yr)	0.00E+00	1.59E-02	1.59E-02	0.015899	3.18E-02	0.031799	**3.18E-02**
Vanadium		(tons/yr)	1.48E-03	1.48E-03	1.48E-03	0.001481	2.96E-03	0.002963	**3.17E-03**
Vinyl Chloride	a	(tons/yr)	0.00E+00	3.05E-02	3.05E-02	0.030469	6.09E-02	0.060938	**6.09E-02**
Vinylidene Chloride	a	(tons/yr)	0.00E+00	1.17E-02	1.17E-02	0.011679	2.34E-02	0.023358	**2.34E-02**
Xylenes	a	(tons/yr)	6.26E-01	5.75E-01	6.26E-01	0.626102	1.25E+00	1.252204	**1.25E+00**
Zinc		(tons/yr)	1.87E-02	1.87E-02	1.87E-02	0.018679	3.74E-02	0.037359	**4.00E-02**

	Facility	2xCTG/DB
Max Single HAP	2.55	2.55
Total HAPs	13.96	13.77

Appendix B: Table B-12
CPV Valley Energy Center
Combined Cycle Unit Non-Criteria Pollutant Emissions
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Notes
Combustion Turbine emissions based on USEPA's AP-42 emission factors except as noted in other footnotes

		AP-42 5th Edition (4/2000)			
		Final Section	Background Document	Final Section	Background Document
		Table 3.1-3 Gas Fired Turbines CT Load (80%-100%) (lb/mmBtu)	Table 3.4-1 Gas Fired Turbines CT Load (<80%) (lb/mmBtu)	Table 3.1-4 and 3.1-5 Oil-Fired Turbines CT Load (80%-100%) (lb/mmBtu)	Table 3.4-2 Oil-Fired Turbines CT Load (<80%) (lb/mmBtu)
	Note				
1,3-Butadiene	a	< 4.30E-07	< 4.29E-07	< 1.60E-05	< 1.65E-05
1,1,1-Trichloroethane					
1,4-Dichlorobenzene	a				< 2.97E-05
2-Methylnapthalene					
3-Methylchloranthrene	a,b				
7,12-Dimethylbenz(a)anthracene	a,b				
Acenaphthene	a,b	8.53E-08		1.36E-05	
Acenaphthylene	a,b	8.53E-08		1.63E-07	
Acetaldehyde	a	4.00E-05	4.45E-05		3.03E-05
Acrolein	a	6.40E-06	8.31E-06		
Ammonia					
Anthracene	a,b	1.14E-07		7.86E-07	
Arsenic	a			< 1.10E-05	< 1.10E-05
Barium					
Benz(a)anthracene	a,b	8.53E-08		2.58E-06	
Benzene	a	1.20E-05	1.03E-04	5.50E-05	5.48E-05
Benzo(a)pyrene	a,b	5.69E-08			
Benzo(b)fluoranthene	a,b	8.53E-08		9.54E-07	
Benzo(b,k)fluoranthene					
Benzo(g,h,i)perylene	a,b	5.69E-08		1.46E-06	
Benzo(k)fluoranthene	a,b	8.53E-08		9.54E-07	
Beryllium	a			< 3.10E-07	< 3.07E-07
Butane					
Cadmium	a			4.80E-06	3.75E-05
Carbon Tetrachloride	a				< 3.06E-05
Chlorobenzene	a				< 2.49E-05
Chloroform	a				< 2.55E-05
Chromium	a			1.10E-05	8.43E-06
Chrysene	a,b	8.53E-08		1.53E-06	
Cobalt	a				
Copper					
Dibenzo(a,h)anthracene	a,b	5.69E-08		1.08E-06	
Dichlorobenzene	a				
Ethane					
Ethylbenzene	a	3.20E-05	2.58E-05		
Ethylene Dichloride	a				2.02E-05
Fluoranthene	a,b	1.42E-07		3.12E-06	
Fluorene	a,b	1.33E-07		2.88E-06	
Formaldehyde	a	1.10E-04	1.10E-04	2.80E-04	2.80E-04
Hexane	a				
Indeno(1,2,3-cd)pyrene	a,b	8.53E-08		1.38E-06	
Lead	a			1.40E-05	1.34E-05
Manganese	a			7.90E-04	7.89E-04
Mercury	a			1.20E-06	1.20E-06
Methlyene Chloride	a				< 2.13E-05
Molybdenum					
Napthalene	a,c	1.30E-06	1.37E-06	3.50E-05	3.52E-05
Nickel	a			< 4.60E-06	1.62E-05
PAH	a,b	< 2.20E-06	2.25E-06	< 4.00E-05	4.03E-05
Pentane					
Phenanathrene	a,b	8.06E-07		6.77E-06	
POM	a				
Propane					
Propylene					
Propylene Oxide	a	< 2.90E-05	< 2.86E-05		
Pyrene	a,b	2.37E-07		2.74E-06	
Selenium	a			< 2.50E-05	< 2.88E-05
Sulfuric Acid					
Tetrachloroethylene	a				< 3.24E-05
Toluene	a	1.30E-04	9.37E-05		
Trichloroethylene	a				< 2.75E-05
Vanadium					
Vinyl Chloride	a				< 5.27E-05
Vinylidene Chloride	a				< 2.02E-05
Xylenes	a	6.40E-05	5.48E-05		
Zinc					

Notes Key

a	indicates compound is one of U.S. EPA's list of 188 HAPs.
b	indicates compound is subset of POM or PAH (PAH is a subset of POM)
c	compound is listed on U.S. EPA's list of 188 HAPs and is a subset of POM or PAH.

PAHs are broken out for turbines using the same split for boilers:

Turbine PAH Emission Rate (Nat Gas):	2.20E-06	lb/MMBtu from AP-42 Table 3.1-3
Turbine PAH Emission Rate (Fuel Oil):	4.00E-05	lb/MMBtu from AP-42 Table 3.1-4

Pollutant	AP-42 Emission Factor Natural Gas lb/mmCF	AP-42 Emission Factor Fuel Oil lb/mgal	Percent of Total Natural Gas (%)	Percent of Total Fuel Oil (%)
Acenaphthene	< 1.80E-06	2.11E-05	3.88%	34.00%
Acenaphthylene	< 1.80E-06	2.53E-07	3.88%	0.41%
Anthracene	< 2.40E-06	1.22E-06	5.17%	1.97%
Benz(a)Anthracene	< 1.80E-06	4.01E-06	3.88%	6.46%
Benzo(a)pyrene	< 1.20E-06		2.59%	0.00%
Benzo(b)fluoranthene	< 1.80E-06	1.48E-06	3.88%	2.39%
Benzo(g,h,I)perylene	< 1.20E-06	2.26E-06	2.59%	3.64%
Benzo(k)fluoranthene	< 1.80E-06	1.48E-06	3.88%	2.39%
Chrysene	< 1.80E-06	2.38E-06	3.88%	3.84%
Dibenzo(a,h)anthracene	< 1.20E-06	1.67E-06	2.59%	2.69%
Fluoranthene	3.00E-06	4.84E-06	6.47%	7.80%
Fluorene	2.80E-06	4.47E-06	6.03%	7.20%
Indeno(1,2,3-cd)pyrene	< 1.80E-06	2.14E-06	3.88%	3.45%
Phenanathrene	1.70E-05	1.05E-05	36.64%	16.92%
Pyrene	5.00E-06	4.25E-06	10.78%	6.85%
Totals	4.64E-05	6.21E-05	100%	100%

Emission factors came from AP-42 Table 1.3-9 and 1.4-3

Formaldehyde emission factor for gas firing (median value for >80% load) obtained from California Air Resource Board (CARB) emission inventory, which can be downloaded from CARB website (www.arb.ca.gov), "software" section, filename - "catef.exe"

Sulfuric acid mist (H_2SO_4) emissions based on mass balance of sulfur in fuel and SO2->SO3 Conversion.

Ammonia slip (NH_3) emissions provided by vendor (ppm) and calculated (lb/hr).

Appendix B: Table B-13

CPV Valley Energy Center

Auxiliary Equipment Non-Criteria Pollutant Emissions

Equipment Parameters:

	Heat Input (mmBtu/hr)	Operation (hrs/year)
Duct Burner	500	2,628
Auxiliary Boiler (gas firing)	73.5	2,000
Emergency Diesel Generator	15.4	500
Diesel Fire Pump	2.3	500
Gas Heater	5.0	8760

Fuel Properties:

Natural Gas Heat Content	1,048	Btu/scf
Natural Gas Sulfur Content	0.80	gr/100scf
Distillate Oil Density	7.1	lb/gal
Distillate Oil Sulfur Content	0.0015%	weight %

Emission Factors & Emissions:

		Duct Burner [1]					Auxiliary Boiler [1], [3]					Emergency Diesel Generator [2]				Diesel Fire Pump [2]				Gas Heater [1], [3]				
		Gas Firing					Gas Firing					Oil Firing				Oil Firing				Gas Firing				
		Emission Factor		Emissions			Emission Factor		Emissions			EF	Emissions			EF	Emissions			Emission Factor		Emissions		
Non-Criteria Pollutants	Note	(lb/mmscf)	(lb/mmBtu)	(lb/hr)	(g/s)	(tons/yr)	(lb/mmscf)	(lb/mmBtu)	(lb/hr)	(g/s)	(tons/yr)	(lb/mmBtu)	(lb/hr)	(g/s)	(tons/yr)	(lb/mmBtu)	(lb/hr)	(g/s)	(tons/yr)	(lb/mmscf)	(lb/mmBtu)	(lb/hr)	(g/s)	(tons/yr)
1,3-Butadiene	a											3.91E-05	6.03E-04	7.60E-05	1.51E-04	3.91E-05	8.89E-05	1.12E-05	2.22E-05					
1,1,1-Trichloroethane																								
1,4 - Dichlorobenzene	a																							
2-Methylnapthalene		2.40E-05	2.35E-08	1.18E-05	1.48E-06	1.55E-05	2.40E-05	2.29E-08	1.68E-06	2.12E-07	1.68E-06									2.40E-05	2.35E-08	1.18E-07	1.49E-08	5.17E-07
3-Methylchloranthrene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07									< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
7,12-Dimethylbenz(a)anthracene	a,b	< 1.60E-05	1.57E-08	7.84E-06	9.88E-07	1.03E-05	< 1.60E-05	1.53E-08	1.12E-06	1.41E-07	1.12E-06									< 1.60E-05	1.57E-08	7.87E-08	9.92E-09	3.45E-07
Acenaphthene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	1.42E-06	2.19E-05	2.76E-06	5.48E-06	1.42E-06	3.23E-06	4.07E-07	8.08E-07	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Acenaphthylene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	5.06E-06	7.81E-05	9.84E-06	1.95E-05	5.06E-06	1.15E-05	1.45E-06	2.88E-06	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Acetaldehyde	a											7.67E-04	1.18E-02	1.49E-03	2.96E-03	7.67E-04	1.74E-03	2.20E-04	4.36E-04					
Acrolein	a											9.25E-05	1.43E-03	1.80E-04	3.57E-04	9.25E-05	2.10E-04	2.65E-05	5.26E-05					
Ammonia		*included in vendor combined cycle emissions estimates*																						
Anthracene	a,b	< 2.40E-06	2.35E-09	1.18E-06	1.48E-07	1.55E-06	< 2.40E-06	2.29E-09	1.68E-07	2.12E-08	1.68E-07	1.87E-06	2.89E-05	3.64E-06	7.21E-06	1.87E-06	4.25E-06	5.36E-07	1.06E-06	< 2.40E-06	2.35E-09	1.18E-08	1.49E-09	5.17E-08
Arsenic	a	2.00E-04	1.96E-07	9.80E-05	1.24E-05	1.29E-04	2.00E-04	1.91E-07	1.40E-05	1.77E-06	1.40E-05									2.00E-04	1.96E-07	9.84E-07	1.24E-07	4.31E-06
Barium		4.40E-03	4.31E-06	2.16E-03	2.72E-04	2.83E-03	4.40E-03	4.20E-06	3.09E-04	3.89E-05	3.09E-04									4.40E-03	4.31E-06	2.17E-05	2.73E-06	9.48E-05
Benz(a)anthracene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	1.68E-06	2.59E-05	3.27E-06	6.48E-06	1.68E-06	3.82E-06	4.82E-07	9.55E-07	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Benzene	a	2.10E-03	2.06E-06	1.03E-03	1.30E-04	1.35E-03	2.10E-03	2.00E-06	1.47E-04	1.86E-05	1.47E-04	9.33E-04	1.44E-02	1.81E-03	3.60E-03	9.33E-04	2.12E-03	2.67E-04	5.31E-04	2.10E-03	2.06E-06	1.03E-05	1.30E-06	4.53E-05
Benzo(a)pyrene	a,b	< 1.20E-06	1.18E-09	5.88E-07	7.41E-08	7.73E-07	< 1.20E-06	1.15E-09	8.41E-08	1.06E-08	8.41E-08	1.88E-07	2.90E-06	3.66E-07	7.25E-07	1.88E-07	4.28E-07	5.39E-08	1.07E-07	< 1.20E-06	1.18E-09	5.91E-09	7.44E-10	2.59E-08
Benzo(b)fluoranthene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	9.91E-08	1.53E-06	1.93E-07	3.82E-07	9.91E-08	2.25E-07	2.84E-08	5.64E-08	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Benzo(b,k)fluoranthene																								
Benzo(g,h,i)perylene	a,b	< 1.20E-06	1.18E-09	5.88E-07	7.41E-08	7.73E-07	< 1.20E-06	1.15E-09	8.41E-08	1.06E-08	8.41E-08	4.89E-07	7.55E-06	9.51E-07	1.89E-06	4.89E-07	1.11E-06	1.40E-07	2.78E-07	< 1.20E-06	1.18E-09	5.91E-09	7.44E-10	2.59E-08
Benzo(k)fluoranthene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	1.55E-07	2.39E-06	3.01E-07	5.98E-07	1.55E-07	3.53E-07	4.44E-08	8.82E-08	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Beryllium	a	< 1.20E-05	1.18E-08	5.88E-06	7.41E-07	7.73E-06	< 1.20E-05	1.15E-08	8.41E-07	1.06E-07	8.41E-07									< 1.20E-05	1.18E-08	5.91E-08	7.44E-09	2.59E-07
Butane		2.10E+00	2.06E-03	1.03E+00	1.30E-01	1.35E+00	2.10E+00	2.00E-03	1.47E-01	1.86E-02	1.47E-01									2.10E+00	2.06E-03	1.03E-02	1.30E-03	4.53E-02
Cadmium	a	1.10E-03	1.08E-06	5.39E-04	6.79E-05	7.09E-04	1.10E-03	1.05E-06	7.71E-05	9.72E-06	7.71E-05									1.10E-03	1.08E-06	5.41E-06	6.82E-07	2.37E-05
Carbon Tetrachloride	a																							
Chlorobenzene	a																							
Chloroform	a																							
Chromium	a	1.40E-03	1.37E-06	6.86E-04	8.65E-05	9.02E-04	1.40E-03	1.34E-06	9.82E-05	1.24E-05	9.82E-05									1.40E-03	1.37E-06	6.89E-06	8.68E-07	3.02E-05
Chrysene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	3.53E-07	5.45E-06	6.86E-07	1.36E-06	3.53E-07	8.03E-07	1.01E-07	2.01E-07	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Cobalt	a	8.40E-05	8.24E-08	4.12E-05	5.19E-06	5.41E-05	8.40E-05	8.02E-08	5.89E-06	7.42E-07	5.89E-06									8.40E-05	8.24E-08	4.13E-07	5.21E-08	1.81E-06
Copper		8.50E-04	8.33E-07	4.17E-04	5.25E-05	5.48E-04	8.50E-04	8.11E-07	5.96E-05	7.51E-06	5.96E-05									8.50E-04	8.33E-07	4.18E-06	5.27E-07	1.83E-05
Dibenzo(a,h)anthracene	a,b	< 1.20E-06	1.18E-09	5.88E-07	7.41E-08	7.73E-07	< 1.20E-06	1.15E-09	8.41E-08	1.06E-08	8.41E-08	5.83E-07	9.00E-06	1.13E-06	2.25E-06	5.83E-07	1.33E-06	1.67E-07	3.32E-07	< 1.20E-06	1.18E-09	5.91E-09	7.44E-10	2.59E-08
Dichlorobenzene	a	1.20E-03	1.18E-06	5.88E-04	7.41E-05	7.73E-04	1.20E-03	1.15E-06	8.41E-05	1.06E-05	8.41E-05									1.20E-03	1.18E-06	5.91E-06	7.44E-07	2.59E-05
Ethane		3.10E+00	3.04E-03	1.52E+00	1.91E-01	2.00E+00	3.10E+00	2.96E-03	2.17E-01	2.74E-02	2.17E-01									3.10E+00	3.04E-03	1.53E-02	1.92E-03	6.68E-02
Ethylbenzene	a																							
Ethylene Dichloride	a																							
Fluoranthene	a,b	3.00E-06	2.94E-09	1.47E-06	1.85E-07	1.93E-06	3.00E-06	2.86E-09	2.10E-07	2.65E-08	2.10E-07	7.61E-06	1.17E-04	1.48E-05	2.94E-05	7.61E-06	1.73E-05	2.18E-06	4.33E-06	3.00E-06	2.94E-09	1.48E-08	1.86E-09	6.47E-08
Fluorene	a,b	2.80E-06	2.75E-09	1.37E-06	1.73E-07	1.80E-06	2.80E-06	2.67E-09	1.96E-07	2.47E-08	1.96E-07	2.92E-05	4.51E-04	5.68E-05	1.13E-04	2.92E-05	6.64E-05	8.37E-06	1.66E-05	2.80E-06	2.75E-09	1.38E-08	1.74E-09	6.04E-08
Formaldehyde	a	7.50E-02	7.35E-05	3.68E-02	4.63E-03	4.83E-02	7.50E-02	7.16E-05	5.26E-03	6.63E-04	5.26E-03	1.18E-03	1.82E-02	2.29E-03	4.55E-03	1.18E-03	2.68E-03	3.38E-04	6.71E-04	7.50E-02	7.35E-05	3.69E-04	4.65E-05	1.62E-03
Hexane	a	1.80E+00	1.76E-03	8.82E-01	1.11E-01	1.16E+00	1.80E+00	1.72E-03	1.26E-01	1.59E-02	1.26E-01									1.80E+00	1.76E-03	8.86E-03	1.12E-03	3.88E-02
Indeno(1,2,3-cd)pyrene	a,b	< 1.80E-06	1.76E-09	8.82E-07	1.11E-07	1.16E-06	< 1.80E-06	1.72E-09	1.26E-07	1.59E-08	1.26E-07	3.75E-07	5.79E-06	7.29E-07	1.45E-06	3.75E-07	8.53E-07	1.07E-07	2.13E-07	< 1.80E-06	1.76E-09	8.86E-09	1.12E-09	3.88E-08
Lead	a	5.00E-04	4.90E-07	2.45E-04	3.09E-05	3.22E-04	5.00E-04	4.77E-07	3.51E-05	4.42E-06	3.51E-05									5.00E-04	4.90E-07	2.46E-06	3.10E-07	1.08E-05
Manganese	a	3.80E-04	3.73E-07	1.86E-04	2.35E-05	2.45E-04	3.80E-04	3.63E-07	2.66E-05	3.36E-06	2.66E-05									3.80E-04	3.73E-07	1.87E-06	2.36E-07	8.19E-06
Mercury	a	2.60E-04	2.55E-07	1.27E-04	1.61E-05	1.67E-04	2.60E-04	2.48E-07	1.82E-05	2.30E-06	1.82E-05									2.60E-04	2.55E-07	1.28E-06	1.61E-07	5.60E-06
Methylene Chloride	a																							
Molybdenum		1.10E-03	1.08E-06	5.39E-04	6.79E-05	7.09E-04	1.10E-03	1.05E-06	7.71E-05	9.72E-06	7.71E-05									1.10E-03	1.08E-06	5.41E-06	6.82E-07	2.37E-05
Napthalene	a,c	6.10E-04	5.98E-07	2.99E-04	3.77E-05	3.93E-04	6.10E-04	5.82E-07	4.28E-05	5.39E-06	4.28E-05	8.48E-05	1.31E-03	1.65E-04	3.27E-04	8.48E-05	1.93E-04	2.43E-05	4.82E-05	6.10E-04	5.98E-07	3.00E-06	3.78E-07	1.31E-05
Nickel	a	2.10E-03	2.06E-06	1.03E-03	1.30E-04	1.35E-03	2.10E-03	2.00E-06	1.47E-04	1.86E-05	1.47E-04									2.10E-03	2.06E-06	1.03E-05	1.30E-06	4.53E-05
PAH	a,b																							
Pentane		2.60E+00	2.55E-03	1.27E+00	1.61E-01	1.67E+00	2.60E+00	2.48E-03	1.82E-01	2.30E-02	1.82E-01									2.60E+00	2.55E-03	1.28E-02	1.61E-03	5.60E-02
Phenanathrene	a,b	1.70E-05	1.67E-08	8.33E-06	1.05E-06	1.10E-05	1.70E-05	1.62E-08	1.19E-06	1.50E-07	1.19E-06	2.94E-05	4.54E-04	5.72E-05	1.13E-04	2.94E-05	6.69E-05	8.43E-06	1.67E-05	1.70E-05	1.67E-08	8.37E-08	1.05E-08	3.66E-07
POM	a																							
Propane		1.60E+00	1.57E-03	7.84E-01	9.88E-02	1.03E+00	1.60E+00	1.53E-03	1.12E-01	1.41E-02	1.12E-01									1.60E+00	1.57E-03	7.87E-03	9.92E-04	3.45E-02
Propylene												2.58E-03	3.98E-02	5.02E-03	9.95E-03	2.58E-03	5.87E-03	7.40E-04	1.47E-03					
Propylene Oxide	a																							
Pyrene	a,b	5.00E-06	4.90E-09	2.45E-06	3.09E-07	3.22E-06	5.00E-06	4.77E-09	3.51E-07	4.42E-08	3.51E-07	4.78E-06	7.38E-05	9.29E-06	1.84E-05	4.78E-06	1.09E-05	1.37E-06	2.72E-06	5.00E-06	4.90E-09	2.46E-08	3.10E-09	1.08E-07
Selenium	a	< 2.40E-05	2.35E-08	1.18E-05	1.48E-06	1.55E-05	< 2.40E-05	2.29E-08	1.68E-06	2.12E-07	1.68E-06									< 2.40E-05	2.35E-08	1.18E-07	1.49E-08	5.17E-07
Sulfuric Acid		*included in vendor combined cycle emissions estimates*						1.67E-04	1.23E-02	1.55E-03	1.23E-02	6.06E-04	9.35E-03	1.18E-03	2.34E-03	6.90E-04	1.37E-03	1.73E-04	3.43E-04		1.67E-04	8.38E-04	1.06E-04	3.67E-03
Tetrachloroethylene	a																							
Toluene	a	3.40E-03	3.33E-06	1.67E-03	2.10E-04	2.19E-03	3.40E-03	3.24E-06	2.38E-04	3.00E-05	2.38E-04	4.09E-04	6.31E-03	7.95E-04	1.58E-03	4.09E-04	9.30E-04	1.17E-04	2.33E-04	3.40E-03	3.33E-06	1.67E-05	2.11E-06	7.33E-05
Trichloroethylene	a																							
Vanadium		2.30E-03	2.25E-06	1.13E-03	1.42E-04	1.48E-03	2.30E-03	2.19E-06	1.61E-04	2.03E-05	1.61E-04									2.30E-03	2.25E-06	1.13E-05	1.43E-06	4.96E-05
Vinyl Chloride	a																							
Vinylidene Chloride	a																							
Xylenes	a											2.85E-04	4.40E-03	5.54E-04	1.10E-03	2.85E-04	6.48E-04	8.17E-05	1.62E-04					
Zinc		2.90E-02	2.84E-05	1.42E-02	1.79E-03	1.87E-02	2.90E-02	2.77E-05	2.03E-03	2.56E-04	2.03E-03									2.90E-02	2.84E-05	1.43E-04	1.80E-05	6.25E-04

Notes:

a	indicates compound is one of U.S. EPA's list of 188 HAPs.
b	indicates compound is subset of POM or PAH (PAH is a subset of POM)
c	compound is listed on U.S. EPA's list of 188 HAPs and is a subset of POM or PAH.

[1] Emissions based on AP-42 5th Edition, Tables 1.4-2, 1.4-3, and 1.4-4 (7/1998) Natural Gas Combustion and Tables 1.3-8, 1.3-9and 1.3-10 (9/1998) Fuel Oil Combustion.

[2] Emissions based on AP-42 5th Edition, Table 3.3-2 (October 1996).

[3] Sulfuric acid emissions from the auxiliary boiler and gas heater based on a mass balance assuming 5% of sulfur converts to H2SO4

Appendix B: Table B-14
CPV Valley Energy Center
Facility-Wide Potential CO2 Emissions

Source(s)	Natural Gas Only: Fuel	Hours/yr	MMBtu/hr	Factor (lb/MMBtu)	CO_2 (tons)	Natural Gas + Oil - With Duct Burning: Fuel	Hours	MMBtu/hr	Factor (lb/MMBtu)	CO_2 (tons)	
2 CTGs	Gas	17,520	1,998	110	1,925,676	Gas	16,080	1,998	110	1,767,401	
2 CTGs	Oil	0	2,145	157	0	Oil	1,440	2,145	157	242,510	
2 DBs	Gas	5,256	500	117.6	154,526	Gas	5,256	500	117.6	154,526	
Total CCs					2,080,202					2,164,438	
Source(s)						Natural Gas + Oil - No Duct Burning: Fuel	Hours	MMBtu/hr	Factor (lb/MMBtu)	CO_2 (tons)	Maximum Annual CO_2 (tons)
2 CTGs						Gas	16,080	1,998	110	1,767,401	
2 CTGs						Oil	1,440	2,145	157	242,510	
2 DBs						Gas	0	0	117.6	0	
Total CCs										2,009,911	2,164,438

Source	Fuel	Hours/yr	MMBtu/hr	Factor (lb/MMBtu)	CO_2 (tons)	
Aux Boiler	Gas	2,000	73.5	117.6	8641	8,641
2 Gas Heaters	Gas	17,520	5.02	117.6	5171	5,171

Source	Fuel	Hours/yr	MMBtu/hr	Factor (lb/MMBtu)	CO_2 (tons)	
EG	Oil	500.00	15.43	164	633	633
FWP	Oil	500.00	2.27	164	93	93

Total PTE	**2,178,977**

APPENDIX C

AGENCY CORRESPONDENCE

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November 14, 2008

Mr. Steven C. Riva
Chief, Permitting Section
United States Environmental Protection Agency, Region 2
290 Broadway, 25th Floor
New York, NY 10007-1866

Subject: **Proposed CPV Valley Energy Center**
Revised Modeling Protocol and Request for Waiver from PSD Preconstruction Monitoring

Dear Mr. Riva:

TRC has been retained by CPV Valley LLC to prepare an air permit application for a proposed nominal 630 megawatt (MW) combined cycle power facility to be known as the CPV Valley Energy Center. The CPV Valley Energy Center will be constructed in the Town of Wawayanda, Orange County, New York.

TRC previously submitted an air quality modeling protocol for CPV Valley Energy Center in September 2008 to the Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC). A revised version of the Air Quality Modeling Protocol is enclosed with this letter. The protocol has been revised to account for subsequent project design changes and to address agency review comments that were provided in response to the original protocol.

This letter also serves to formally request a waiver from PSD preconstruction monitoring requirements for the CPV Valley Energy Center. Pursuant to 40 CFR 52.21(i)(5)(i), an applicant for a PSD permit can request an exemption from preconstruction monitoring requirements if it can be demonstrated that its air quality impacts will be less than the significant monitoring concentrations (SMCs) listed therein.

The following table provides a summary of maximum predicted impacts from the proposed CPV Valley Energy Center along with the associated SMCs. The predicted impacts were obtained using procedures described in the revised Air Quality Modeling Protocol.

Pollutant	Significant Monitoring Concentration ($\mu g/m^3$)	Maximum Project Impact ($\mu g/m^3$)	Averaging Period
Carbon monoxide (CO)	575	181.9 [a]	8-hour
Nitrogen dioxide (NO_2)	14	0.8	Annual
Particulate matter (PM-10)	10	9.9 [a]	24-hour
Sulfur dioxide (SO_2)	13	0.6	24-hour
Lead (Pb)	0.1	0.009 [b]	3-month
Notes: a. Short-term impacts of CO and PM account for higher impacts that may occur during combustion turbine startup. b. Predicted impacts for Pb represent maximum 24-hour impacts during oil firing in combustion turbines. Impacts for 3-month averaging period would be much smaller.			

With this letter CPV Valley LLC is formally requesting a waiver from preconstruction monitoring requirements. If you should require additional information on the revised Air Quality Modeling Protocol or the request for a waiver from preconstruction monitoring, please do not hesitate to contact me at (978) 656-3670 or jpollack@trcsolutions.com.

Sincerely,

TRC

Jon A. Pollack

Jon A. Pollack
Senior Air Quality Consultant

cc: A. Colter, U.S. EPA Region II Permitting Section
L. Sedefian, NYSDEC
S. Remillard, CPV
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November 14, 2008

Ms. Jill Webster
Environmental Scientist
United States Department of Interior
U.S. Fish & Wildlife Refuge System
7333 W. Jefferson Ave., Suite 375
Lakewood, Colorado 80235-2017

Subject: **Proposed CPV Valley Energy Center**
Need for Class I Area Air Quality and Air Quality Related Values (AQRV) Analyses for the Brigantine Class I Area

Dear Ms. Webster:

TRC has been retained by CPV Valley LLC to prepare an air permit application for a proposed nominal 630 megawatt (MW) combined cycle power facility to be known as the CPV Valley Energy Center. The CPV Valley Energy Center will be constructed in the Town of Wawayanda, Orange County, New York. The site is located in the northeast portion of the Town of Wawayanda near the boundary with the City of Middletown on a parcel that is north of Interstate Route 84, east of New York Route 17M, and south and west of New York Route 6. The emissions from the project will be approximately centered at the following location: (546,986 meters UTM East; 4,584,674 meters UTM North; NAD 83, Zone 18).

The facility will include two Siemens Westinghouse SGT6-5000F combustion turbines, two heat recovery steam generators (HRSGs) equipped with natural gas-fired duct burners for supplementary firing, and a single steam turbine generator (STG) with an air cooled condenser. The combustion turbines will be primarily fired with natural gas. The backup use of ultra low sulfur diesel (ULSD) with a maximum sulfur content of 15 parts per million (ppm) is proposed for up to the equivalent of 720 hours per year per turbine.

The combustion turbines will use a dry low-NO_x combustor for gas firing and water injection for control of nitrogen oxides (NO_x) when firing ULSD. A selective catalytic reduction (SCR) system will be used to further control NO_x emissions. An oxidation catalyst will be used to control the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The firing of natural gas and ULSD in the combustion turbines will minimize emissions of particulate matter with an aerodynamic diameter less than 10 microns (PM-10), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4). The use of air cooled condensers will also avoid PM-10 emissions associated with wet cooling systems that are often used with combined cycle projects.

Exhaust gases from the combined cycle units will be directed to two 275 foot tall stacks that are slightly below the calculated Good Engineering Practice stack height of 287.5 feet.

Estimated potential short-term (24-hour) maximum natural gas and oil fired emissions and annual emissions from the combined cycle units are presented in Table 1. The PM-10 emission rates presented in Table 1 include filterable and condensable particulates. The facility-wide PM-10 (and PM-2.5) emissions will be limited on an annual basis to 95 tons per year (tpy) under a proposed emissions cap.

Table 1: Estimated Potential Emissions

Pollutant	Combustion Turbines' Maximum Short-Term Emissions[1] (lb/hr)		Annual Emissions[2] (tpy)
	Natural Gas-Fired	Ultra Low Sulfur Fuel Oil	
Nitrogen Oxides (NO_x)	41.6	102.9	168.5
Sulfur Dioxide (SO_2)	12.0	6.5	41.0
Particulate Matter with an aerodynamic diameter less than 10 microns (PM-10)	33.1	116.0	94.2
Sulfuric Acid Mist (H_2SO_4)	3.7	2.0	12.6

[1] Maximum short-term emission rates based on two combustion turbines operating at the minimum temperature conditions (-5°F). Emission rates for natural gas firing include maximum proposed level of duct firing.

[2] Annual emissions based on two combustion turbines each operating up to 8,760 hours per year (hr/yr) on natural gas firing at average temperature conditions (51◦F) with duct firing occurring for 2,628 of those hours and up to 720 hr/yr on ULSD firing at minimum temperature conditions (-5°F). Annual PM-10 emissions reflect proposed emissions cap.

The minimum distance from the CPV Valley Energy Center site to the Brigantine Wilderness Area Class I area in New Jersey is approximately 206 km. Following the Draft Revised Federal Land Managers' Air Quality Related Values Workgroup (FLAG) guidance (June 2008), we believe that this project is eligible for an exemption from the requirement to perform a Class I area modeling analysis because of its inherent low emissions and distance to Class I areas.

We understand that the maximum short-term emission rates are used in the exemption analysis even if annual emissions are limited. Assuming full year operation (8,760 hours) of the turbines firing natural gas, the resulting annual emissions of NO_x, SO_2, PM-10, and H_2SO_4 would be equal to (41.6 + 12.0 + 33.1 + 3.7) lb/hr x 8760 hr/yr x ton/2000 lb = 393.95 tons. The resulting ratio of emissions in tpy to distance in km ("Q/D") would be given by (393.95 tpy)/(206 km), or approximately 1.9.

Assuming full year operation of the turbines firing ULSD (even though oil firing would be limited to the equivalent of 720 hours per year and although annual emissions of PM-10 will be capped), yields annual emissions of NO_x, SO_2, PM-10, and H_2SO_4 equal to (102.9 + 6.5 + 116.0 + 2.0) lb/hr x 8760 hr/yr x ton/2000 lb = 996 tons. The resulting Q/D ratio for ULSD firing is given by (996.0 tons)/(206 km), or approximately 4.8.

Our understanding of the draft revised FLAG guidance is that a project with a Q/D ratio of ≤ 10 is considered to have negligible impacts on AQRVs and is normally exempt from any additional Class I impact or AQRV analysis. The Q/D ratios calculated for the turbines for scenarios involving the firing of natural gas and ULSD are all much less than 10. Therefore, we believe that this project qualifies for an exemption from Class I modeling impact requirements.

With this letter CPV Valley LLC is formally requesting a decision on the need for Class I area air quality and AQRV analyses for the Brigantine Wilderness Area based on the potential emissions presented herein. If you should require additional information on the proposed project or have any questions, please do not hesitate to contact me at (978) 656-3670 or jpollack@trcsolutions.com.

Sincerely,

TRC

Jon A. Pollack

Jon A. Pollack
Senior Air Quality Consultant

cc: S. Rivas, U.S. EPA Region II Permitting Section
A. Colter, U.S. EPA Region II Permitting Section
S. Remillard, CPV
G. Harkness, TRC
C. Adduci, TRC
J. Snyder, TRC
L. Schulman, TRC

Wannalancit Mills
650 Suffolk Street, Suite 200
Lowell, MA 01854

978.970.5600 PHONE
978.453.1995 FAX

www.TRCsolutions.com

November 14, 2008

Ms. Margaret Mitchell
Forest Supervisor
Green Mountain National Forest
231 North Main Street
Rutland, VT

Subject: Proposed CPV Valley Energy Center
Need for Class I Area Air Quality and Air Quality Related Values (AQRV) Analyses for the Lye Brook Class I Area

Dear Ms. Webster:

TRC has been retained by CPV Valley LLC to prepare an air permit application for a proposed nominal 630 megawatt (MW) combined cycle power facility to be known as the CPV Valley Energy Center. The CPV Valley Energy Center will be constructed in the Town of Wawayanda, Orange County, New York. The site is located in the northeast portion of the Town of Wawayanda near the boundary with the City of Middletown on a parcel that is north of Interstate Route 84, east of New York Route 17M, and south and west of New York Route 6. The emissions from the project will be approximately centered at the following location: (546,986 meters UTM East; 4,584,674 meters UTM North; NAD 83, Zone 18).

The facility will include two Siemens Westinghouse SGT6-5000F combustion turbines, two heat recovery steam generators (HRSGs) equipped with natural gas-fired duct burners for supplementary firing, and a single steam turbine generator (STG) with an air cooled condenser. The combustion turbines will be primarily fired with natural gas. The backup use of ultra low sulfur diesel (ULSD) with a maximum sulfur content of 15 parts per million (ppm) is proposed for up to the equivalent of 720 hours per year per turbine.

The combustion turbines will use a dry low-NO_x combustor for gas firing and water injection for control of nitrogen oxides (NO_x) when firing ULSD. A selective catalytic reduction (SCR) system will be used to further control NO_x emissions. An oxidation catalyst will be used to control the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The firing of natural gas and ULSD in the combustion turbines will minimize emissions of particulate matter with an aerodynamic diameter less than 10 microns (PM-10), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4). The use of air cooled condensers will also avoid PM-10 emissions associated with wet cooling systems that are often used with combined cycle projects.

Exhaust gases from the combined cycle units will be directed to two 275 foot tall stacks that are slightly below the calculated Good Engineering Practice stack height of 287.5 feet.

Estimated potential short-term (24-hour) maximum natural gas and oil fired emissions and annual emissions from the combined cycle units are presented in Table 1. The PM-10 emission rates presented in Table 1 include filterable and condensable particulates. The facility-wide PM-10 (and PM-2.5) emissions will be limited on an annual basis to 95 tons per year (tpy) under a proposed emissions cap.

Table 1: Estimated Potential Emissions

Pollutant	Combustion Turbines' Maximum Short-Term Emissions[1] (lb/hr)		Annual Emissions[2] (tpy)
	Natural Gas-Fired	Ultra Low Sulfur Fuel Oil	
Nitrogen Oxides (NO_x)	41.6	102.9	168.5
Sulfur Dioxide (SO_2)	12.0	6.5	41.0
Particulate Matter with an aerodynamic diameter less than 10 microns (PM-10)	33.1	116.0	94.2
Sulfuric Acid Mist (H_2SO_4)	3.7	2.0	12.6

[1] Maximum short-term emission rates based on two combustion turbines operating at the minimum temperature conditions (-5°F). Emission rates for natural gas firing include maximum proposed level of duct firing.

[2] Annual emissions based on two combustion turbines each operating up to 8,760 hours per year (hr/yr) on natural gas firing at average temperature conditions (51°F) with duct firing occurring for 2,628 of those hours and up to 720 hr/yr on ULSD firing at minimum temperature conditions (-5°F). Annual PM-10 emissions reflect proposed emissions cap.

The minimum distance from the CPV Valley Energy Center site to the Lye Brook Wilderness Area Class I area in Vermont is approximately 215 km. Following the Draft Revised Federal Land Managers' Air Quality Related Values Workgroup (FLAG) guidance (June 2008), we believe that this project is eligible for an exemption from the requirement to perform a Class I area modeling analysis because of its inherent low emissions and distance to Class I areas.

We understand that the maximum short-term emission rates are used in the exemption analysis even if annual emissions are limited. Assuming full year operation (8,760 hours) of the turbines firing natural gas, the resulting annual emissions of NO_x, SO_2, PM-10, and H_2SO_4 would be equal to (41.6 + 12.0 + 33.1 + 3.7) lb/hr x 8760 hr/yr x ton/2000 lb = 393.95 tons. The resulting ratio of emissions in tpy to distance in km ("Q/D") would be given by (393.95 tpy)/(215 km), or approximately 1.8.

Assuming full year operation of the turbines firing ULSD (even though oil firing would be limited to the equivalent of 720 hours per year and although annual emissions of PM-10 will be capped), yields annual emissions of NO_x, SO_2, PM-10, and H_2SO_4 equal to (102.9 + 6.5 + 116.0 + 2.0) lb/hr x 8760 hr/yr x ton/2000 lb = 996 tons. The resulting Q/D ratio for ULSD firing is given by (996.0 tons)/(215 km), or approximately 4.6.

Our understanding of the draft revised FLAG guidance is that a project with a Q/D ratio of ≤ 10 is considered to have negligible impacts on AQRVs and is normally exempt from any additional Class I impact or AQRV analysis. The Q/D ratios calculated for the turbines for scenarios involving the firing of natural gas and ULSD are all much less than 10. Therefore, we believe that this project qualifies for an exemption from Class I modeling impact requirements.

With this letter CPV Valley LLC is formally requesting a decision on the need for Class I area air quality and AQRV analyses for the Lye Brook Wilderness Area based on the potential emissions presented herein. If you should require additional information on the proposed project or have any questions, please do not hesitate to contact me at (978) 656-3670 or jpollack@trcsolutions.com.

Sincerely,

TRC

Jon A. Pollack

Jon A. Pollack
Senior Air Quality Consultant

cc: S. Rivas, U.S. EPA Region II Permitting Section
A. Colter, U.S. EPA Region II Permitting Section
S. Remillard, CPV
G. Harkness, TRC
C. Adduci, TRC
J. Snyder, TRC
L. Schulman, TRC

United States Department of the Interior

FISH AND WILDLIFE SERVICE
New York Field Office
3817 Luker Road
Cortland, NY 13045
Phone: (607) 753-9334 Fax: (607) 753-9699
http://www.fws.gov/northeast/nyfo

Project Number: 80175

To: Beverly Schultz Date: 1-3-08

Regarding: Combined cycle power plant

Town/County: Town of Wawayanda / Orange County

We have received your request for information regarding occurrences of Federally-listed threatened and endangered species within the vicinity of the above-referenced project/property. Due to increasing workload and reduction of staff, we are no longer able to reply to endangered species list requests in a timely manner. In an effort to streamline project reviews, we are shifting the majority of species list requests to our website at http://www.fws.gov/northeast/nyfo/es/section7.htm. Please go to our website and print the appropriate portions of our county list of endangered, threatened, proposed, and candidate species, and the official list request response. Step-by-step instructions are found on our website.

As a reminder, Section 9 of the Endangered Species Act (ESA) (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*) prohibits unauthorized taking* of listed species and applies to Federal and non-Federal activities. Additionally, endangered species and their habitats are protected by Section 7(a)(2) of the ESA, which requires Federal agencies, in consultation with the U.S. Fish and Wildlife Service (Service), to ensure that any action it authorizes, funds, or carries out is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat. An assessment of the potential direct, indirect, and cumulative impacts is required for all Federal actions that may affect listed species. For projects not authorized, funded, or carried out by a Federal agency, consultation with the Service pursuant to Section 7(a)(2) of the ESA is not required. However, no person is authorized to "take"* any listed species without appropriate authorizations from the Service. Therefore, we provide technical assistance to individuals and agencies to assist with project planning to avoid the potential for "take," or when appropriate, to provide assistance with their application for an incidental take permit pursuant to Section 10(a)(1)(B) of the ESA.

Project construction or implementation should not commence until all requirements of the ESA have been fulfilled. If you have any questions or require further assistance regarding threatened or endangered species, please contact the Endangered Species Program at (607) 753-9334. Please refer to the above document control number in any future correspondence.

Endangered Species Biologist: Robyn A. Niver RAN

*Under the Act and regulations, it is illegal for any person subject to the jurisdiction of the United States to *take* (includes harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect; or to attempt any of these), import or export, ship in interstate or foreign commerce in the course of commercial activity, or sell or offer for sale in interstate or foreign commerce any endangered fish or wildlife species and most threatened fish and wildlife species. It is also illegal to possess, sell, deliver, carry, transport, or ship any such wildlife that has been taken illegally. "Harm" includes any act which actually kills or injures fish or wildlife, and case law has clarified that such acts may include significant habitat modification or degradation that significantly impairs essential behavioral patterns of fish or wildlife.

Orange County

Federally Listed Endangered and Threatened Species and Candidate Species

This list represents the best available information regarding known or likely County occurrences of Federally-listed and candidate species and is subject to change as new information becomes available.

Common Name	Scientific Name	Status
Atlantic Sturgeon[2]	*Acipenser oxyrinchus oxyrinchus*	C
Bald eagle[1]	*Haliaeetus leucocephalus*	D
Bog turtle	*Clemmys [=Glyptemys] muhlenbergii*	T
Indiana bat (S)	*Myotis sodalis*	E
Dwarf wedge mussel	*Alasmidonta heterodon*	E
Shortnose sturgeon[2]	*Acipenser brevirostrum*	E

Status Codes: E=Endangered T=Threatened P=Proposed C=Candidate D=Delisted

W=Winter S=Summer

[1] The bald eagle was delisted on August 8, 2007. While there are no ESA requirements for bald eagles after this date, the eagles continue to receive protection under the Bald and Golden Eagle Protection Act (BGEPA). Please follow the Service's May 2007 Bald Eagle Management Guidelines to determine whether you can avoid impacts under the BGEPA for your projects. If you have any questions, please contact the endangered species branch in our office.

[2] Primarily occurs in Hudson River. Principal responsibility for this species is vested with the National Oceanic and Atmospheric Administration/Fisheries.

Information current as of: 9/23/108

Print Species List

APPENDIX D

ADDITIONAL USEPA AND NYSDEC PERMIT APPLICATION FORMS

- CERTIFICATE OF REPRESENTATION (ACID RAIN AND CAIR)
- ACID RAIN PERMIT APPLICATION
- NO_X BUDGET PERMIT APPLICATION
- ADR NO_X BUDGET PERMIT APPLICATION
- ACCOUNT CERTIFICATE OF REPRESENTATION NO_X (ADR NO_X BUDGET TRADING PROGRAM)
- ACCOUNT CERTIFICATE OF REPRESENTATION (NO_X BUDGET TRADING PROGRAM)
- ADR SO_2 BUDGET PERMIT APPLICATION
- ACCOUNT CERTIFICATE OF REPRESENTATION SO_2 (ADR SO_2 BUDGET TRADING PROGRAM)

United States
Environmental Protection Agency
Acid Rain, CAIR, and CAMR Programs OMB Nos. 2060-0258, 2060-0567, 2060-0570, and 2060-058

EPA

Certificate of Representation

Page

For more information, see instructions and 40 CFR 72.24; 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR) NO_X Annual, SO_2, and NO_X Ozone Season Trading Programs; 40 CFR 97.113, 97.213, or 97.313; or 40 CFR 60.4113, or a comparable state regulation under the Clean Air Mercury Rule (CAMR), as applicable.

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

FACILITY (SOURCE) INFORMATION

STEP 1
Provide information for the facility (source).

Facility (Source) Name CPV Valley Energy Center	State NY	Plant Code 56940
County Name Orange County		
Latitude 41.413 N	Longitude 74.435 W	

STEP 2
Enter requested information for the designated representative.

Name Steve Remillard	Title Director of Development
Company Name CPV Valley, LLC	
Address 50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184	
Phone Number 781-817-8970	Fax Number 781-848-5804
E-mail address sremillard@cpv.com	

STEP 3
Enter requested information for the alternate designated representative.

Name	Title
Company Name	
Address	
Phone Number	Fax Number
E-mail address	

CPV Valley Energy Center

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): X Acid Rain X CAIR NO_X Annual X CAIR SO_2 X CAIR NO_X Ozone Season ~ CAMR (Hg Budget Trading) ~ CAMR (Nontrading)

Unit ID#	Unit Type	Source Category / NAICS Code
0001	CC	Source Category **Electric Utility**
		NAICS Code **221112**

Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): **06/01/2012**

Check One: Actual ~ Projected X

Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR-CAMR Nameplate Capacity (MWe)
00001	NA	NA

Company Name	Owner / Operator
Company Name: **CPV Valley, LLC**	X Owner X Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator

CPV Valley Energy Center

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): X Acid Rain X CAIR NO_X Annual X CAIR SO_2 X CAIR NO_X Ozone Season ~ CAMR (Hg Budget Trading) ~ CAMR (Nontrading)

0002 Unit ID#	CC Unit Type	Source Category Electric Utility NAICS Code 221112
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): 06/01/2012		Check One: Actual ~ Projected X

Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR-CAMR Nameplate Capacity (MWe)
00002	NA	NA

Company Name: CPV Valley, LLC	X Owner X Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator

STEP 5: Read the appropriate certification statements, sign, and date.

Acid Rain Program

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.e., the source and each unit subject to the Acid Rain Program, as indicated in "Applicable Program(s)" in Step 4).

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 each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and 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 a life-of-the-unit, firm power contractual arrangement, 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 each affected unit at the source; and
>
> Allowances, and 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, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source (i.e., the source and each unit subject to the CAIR NO_X Annual Trading Program, as indicated in "Applicable Program(s)" in Step 4).

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

I certify that the owners and operators of the CAIR NO_X source and each CAIR NO_X 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, a CAIR NO_X unit, or where a utility or industrial customer purchases power from a CAIR NO_X unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

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

Clean Air Interstate Rule (CAIR) SO_2 Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source (i.e., the source and each unit subject to the SO_2 Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program, on behalf of the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO_2 source and each CAIR SO_2 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, a CAIR SO_2 unit, or where a utility or industrial customer purchases power from a CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO_2 source and each CAIR SO_2 unit at the source; and

CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO_2 allowances by contract, CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_X Ozone Season Trading Program, as indicated in "Applicable Program(s)" in Step 4).

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

I certify that the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit 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, a CAIR NO_X Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit; and

CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X Ozone Season allowances by contract, CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Facility(Source) Name (from Step 1) **CPV Valley Energy Center**

Clean Air Mercury Rule (CAMR) Hg Budget Trading Program

I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Hg Budget unit at the source (i.e., the source and each unit subject to the CAMR Hg Budget Trading Program, as indicated in "Applicable Program(s)" in Step 4).

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

I certify that the owners and operators of the source and of each Hg Budget 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, a Hg Budget unit, or where a utility or industrial customer purchases power from a Hg Budget unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

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

Clean Air Mercury Rule (CAMR) Program Other Than the Hg Budget Trading Program

I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each electric generating unit (EGU) (as defined at 40 CFR 60.24(h)(8)) at the source (i.e., the source and each unit subject to a CAMR Program other than the Hg Budget Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all the necessary authority to carry out my duties and responsibilities under a State Plan approved by the Administrator as meeting the requirements of 40 CFR 60.24(h) on behalf of the owners and operators of the source and of each EGU at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the source and of each EGU 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 EGU, or where a utility or industrial customer purchases power from an EGU under a life-of-the-unit, firm power contractual arrangement, I certify that I have given a written notice of my selection as the Hg designated representative or alternate Hg designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each EGU at the source.

Facility (Source) Name (from Step 1) **CPV Valley Energy Center**

General

I am authorized to make this submission on behalf of the owners and operators of the source or 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 11/24/08
Signature (Alternate Designated Representative)	Date

Instructions for the Certificate of Representation

Note: The Certificate of Representation information can be submitted <u>online</u> through the CAMD Business System (CBS) at https://camd.epa.gov/cbs/index.cfm. You must have a user ID and password. If you need a user ID and password, or if you have questions about CBS, contact Laurel DeSantis at desantis.laurel@epa.gov or (202) 343-9191, or Alex Salpeter at salpeter.alex@epa.gov or (202) 343-9157.

Any reference in these instructions to the Designated Representative means the Acid Rain Designated Representative, CAIR Designated Representative, and/or Hg Designated Representative, as applicable. Any reference to the Alternate Designated Representative means the Alternate Acid Rain Designated Representative, the Alternate CAIR Designated Representative, and/or the Alternate Hg Designated Representative, as applicable. As reflected in this form, the Acid Rain Designated Representative, the CAIR Designated Representative, and the Hg Designated Representative for a facility (source) must be the same individual, and the Alternate Acid Rain Designated Representative, the Alternate CAIR Designated Representative, and the Alternate Hg Designated Representative for a facility (source) must be the same individual.

Please type or print. Submit one copy of page 2 for each unit subject to the Acid Rain Program, a CAIR Trading Program, or a CAMR Program, at the facility (source), and indicate the page order and total number of pages (*e.g.*, 1 of 4, 2 of 4, etc.) in the boxes in the upper right hand corner of page 2. **A Certificate of Representation amending an earlier submission supersedes the earlier submission in its entirety and must therefore always be complete**. Submit one Certificate of Representation form with <u>original</u> signature(s). **NO FIELDS SHOULD BE LEFT BLANK.** For assistance, contact Laurel DeSantis at desantis.laurel@epa.gov or (202) 343-9191.

STEP 1

(i) A Plant Code is a 4 or 5 digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, contact EIA at (202) 586-4325 or (202) 586-2402. For facilities that do not produce electricity, use the facility identifier assigned by EPA (beginning with "88"). If the facility does not produce electricity and has not been assigned a facility identifier, contact Laurel DeSantis at desantis.laurel@epa.gov or (202) 343-9191.

(ii) Enter the latitude and longitude representing the location of the facility in degree decimal format.

Note that coordinates MUST be submitted in decimal degree format; in this format minutes and seconds are represented as a decimal fraction of one degree. Therefore, coordinates containing degrees, minutes, and seconds must first be converted using the formula:

decimal degrees = degrees + (minutes / 60) + (seconds / 3600)

Example:
39 degrees, 15 minutes, 25 seconds = 39 + (15 / 60) + (25 / 3600) = 39.2569 degrees

STEPS 2 & 3

The Designated Representative and the Alternate Designated Representative must be individuals (i.e., natural persons) and cannot be a company. Enter the company name and address of the representative as it should appear on all correspondence. If an email address is provided, most correspondence will be emailed. **Although not required, EPA strongly encourages owners and operators to designate an Alternate Designated Representative to act on behalf of the Designated Representative.**

STEP 4

(i) Complete one page for each unit subject to the Acid Rain Program, a CAIR Trading Program, or a CAMR Program, and indicate the program(s) to which the unit is subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.) Identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in previously submitted Certificates of Representation (if applicable) and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each submission to EPA that includes the unit identification number(s) (e.g., monitoring plans and quarterly reports) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation. Do not identify units that are not subject to the above-listed programs but are part of a common monitoring configuration with a unit that is subject to any of these programs. To identify units in a common monitoring configuration that are not subject to any of these programs, call the CAMD Hotline at (202) 343-9620, and leave a message under the "CEMS" submenu.

(ii) Identify the type of unit using one of the following abbreviations:

<u>Boilers</u>		<u>Boilers</u>		<u>Turbines</u>	
AF	Arch-fired boiler	**OB**	Other boiler	**CC**	Combined cycle
BFB	Bubbling fluidized bed boiler	**PFB**	Pressurized fluidized bed boiler	**CT**	Combustion turbine
C	Cyclone boiler	**S**	Stoker	**OT**	Other turbine
CB	Cell burner boiler	**T**	Tangentially-fired boiler	<u>Others</u>	
CFB	Circulating fluidized bed boiler	**WBF**	Wet bottom wall-fired boiler	**ICE**	Internal combustion engine
DB	Dry bottom wall-fired boiler	**WBT**	Wet bottom turbo-fired boiler	**KLN**	Cement kiln
DTF	Dry bottom turbo-fired boiler	**WVF**	Wet bottom vertically-fired boiler	**PRH**	Refinery process heater
DVF	Dry bottom vertically-fired boiler				

If there is uncertainty about how a unit should be characterized, contact Robert Miller at <u>miller.robertl@epa.gov</u> or (202) 343-9077.

(iii) Indicate the source category description that most accurately describes the purpose forwhich the unit is operated by entering one of the following terms. If none of these descriptionsapplies to your unit, contact Robert Miller at miller.robertl@epa.gov or (202) 343-9077.

Automotive Stampings	Industrial Boiler	Petroleum Refinery
Bulk Industrial Chemical	Industrial Turbine	Portland Cement Plant
Cement Manufacturing	Institutional	Pulp and Paper Mill
Cogeneration	Iron and Steel	Small Power Producer
Electric Utility	Municipal Waste Combustor	Theme Park

(iv) Provide the primary North American Industrial Classification System (NAICS) code that most accurately describes the business type for which the unit is operated. If unknown, go to http://www.census.gov for guidance on how to determine the proper NAICS code for the unit.

(v) Enter the date the unit began (or will begin) serving any generator producingelectricity for sale, including test generation. Enter this date and check the "actual" box for any unit that hasbegun to serve a generator producing electricity for sale as of the date of submission of this form. (This information should be provided even if the unit does not currently serve a generator producing electricity for sale.) For any unit that will begin, but has not begun as of the date of submission of this form, to serve a generator producing electricity for sale, estimate the future date onwhich the unit will begin to produce electricity for sale and check the "projected" box. When the actual date is established, revise the form accordingly by entering the actual date and checking the "actual" box. Enter "NA" if the unit has not ever served, is notcurrently serving, and is not projected toserve, a generator that producing electricity for sale. **You are strongly encouraged to use the CAMD Business System to update information regarding when a unit begins serving a generator producing electricity for sale.**

If you have questions regarding this portion of the form, contact Robert Miller at miller.robertl@epa.gov or (202) 343-9077.

(vi) For a unit subject to the Acid Rain Program, a CAIR Trading Program, or a CAMR Program that, as of the date of submission of this form, serves one or more generators (whether or not the generator produces electricity for sale), indicate the generator ID number and the nameplate capacity (in MWe) of each generator served by the unit. A unit serves a generator if it produces, or is able to produce, steam, gas, or other heated medium for generating electricity at that generator. For combined cycle units, report separately the nameplate capacities of the generatorsassociated with the combustion turbine and the steam turbine. Pleaseensure that the generator ID numbers entered are consistent with those reported to the EIA.

The definitions of "nameplate capacity" under theAcid Rain Program, andunder the CAIR or CAMR Programs, differ slightly. Therefore, for a unit subject to the Acid Rain Program, and any CAIR or CAMR Program, the nameplate capacity for the same generator under the Acid Rain Program and under the CAIR or CAMR Program, may differ in certain limited circumstances. Specifically, for a unit subject to the Acid Rain Program, the nameplate capacity of a generator, if listed in the National Allowance Database ("NADB"), is not affected by physical changes to thegenerator after initial installation that result in an increase in the maximum electrical generating output that the generator is capable of producing. Otherwise, for a unit subject to the Acid Rain Program, or a CAIR or CAMR Program, the nameplate capacity of a generator is affected by physical changes to the generator after initial installation that result in an increase in the maximum electrical generating output that the generator is capable of producing. In such a case, the higher maximum electrical generating output number in MWe should be reported in the nameplate capacity column. Enter "NA" if, as of the date of submission of this form, the unit does not serve a generator.

See the definition of "nameplate capacity" at 40 CFR 72.2, 96.102, 97.102, 96.202, 97.202, 96.302, 97.302, 60.24(h)(8), and 60.4102, as applicable. The NADB is located at the CAMD website at http://www.epa.gov/airmarkets/trading/allocations.html. If you have questions regarding nameplate capacity, contact Robert Miller atmiller.robertl@epa.gov or (202) 343-9077; if you have questions regarding the NADB, contact Craig Hillock at hillock.craig@epa.gov or (202) 343-9105.

(vii) Enter the company name of each ownerand operator in the "Company Name" field. Indicate whether the company is the owner, operator, or both.For new units, if the operator of a unit has not yet been chosen, indicate that the owner is both the owner andoperator and submit a revised form when the operator has been selected within 30 days of the effective date of the selection. EPA must be notified of changes to owners and operators within 30 days of the effective date of the change. **You are strongly encouraged to use theCAMD Business System to provide updated information on owners and operators.**

STEP 5

Read the appropriate certification statements, sign, and date. Note that for sources subject toCAMR, the first set of CAMR certification statements apply to sources in states that are participating in the Hg Budget Trading Program. The second set of certification statements apply to sources in statesthat are not participating in the Hg Budget Trading Program.

Mail this form to:

For regular/certified mail:

U.S. Environmental Protection Agency
Clean Air Markets Division (6204J)
Attention: Designated Representative
1200 Pennsylvania Avenue, NW
Washington, DC 20460

For overnight mail:

U.S. Environmental Protection Agency
Clean Air Markets Division (6204J)
Attention: Designated Representative
1310 L Street, NW
Second Floor
Washington, DC 20005
(202) 343-9191

Submit this form prior to making any other submissions under the Acid Rain Program, CAIR NO_X Trading Program, CAIR SO_2 Trading Program, CAIR NO_X Ozone Season Trading Program, CAMR Hg Budget Trading Program, or CAMR Program other than Hg Budget Trading Program. Submit a revised Certificate of Representation when any information in the existing Certificate of Representation changes. **You are strongly encouraged touse the CAMD Business System to provide updated information.**

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 15 hours per response annually. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes ofcollecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit orotherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collectionof information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: X new ~ revised ~ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name :	State	Plant Code
CPV Valley Energy Center	**NY**	56940

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
0001	Yes
0002	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Facility (Source) Name (from STEP 1) **CPV Valley Energy Center**

Permit Requirements

STEP 3

Read the standard 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 source or unit, as appropriate, 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 source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; 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).

Facility (Source) Name (from STEP 1) **CPV Valley Energy Center**

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(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, oran 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 ofthe source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source 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 source 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 certifcate 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;

Facility (Source) Name (from STEP 1) **CPV Valley Energy Center**

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(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.
(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.
(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

Facility (Source) Name (from STEP 1) **CPV Valley Energy Center**

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source 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 **Steve Remillard**	
Signature	Date 11/24/08

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, contact EIA at (202) 586-4325 or (202) 586-2402.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority=s operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

NOx Budget Permit Application

For more information, refer to 40 CFR 97.21 and 97.22

This submission is: X New ☐ Revised

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

Plant Name	**CPV Valley Energy Center**	State	**NY**	ORIS/Facility Code	56940

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 source required to have a federally enforceable permit and each NOx Budget unit required to have a federally enforceable permit at the source shall:

> (i) Submit to the permitting authority a complete NOx Budget permit application under § 97.22 in accordance with the deadlines specified in § 97.21(b) and (c);
>
> (ii) Submit in a timely manner any supplemental information that the permitting authority 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 source required to have a federally enforceable permit and each NOx Budget unit required to have a federally enforceable permit at the source shall have a NOx Budget permit issued by the permitting authority and operate the unit in compliance with such NOx Budget permit.

(3) The owners and operators of a NOx Budget source that is not otherwise required to have a federally enforceable permit are not required to submit a NOx Budget permit application, and to have a NOx Budget permit, under subpart C of 40 CFR part 97 for such NOx Budget source.

(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 H of 40 CFR part 97.
(2) The emissions measurements recorded and reported in accordance with subpart H of 40 CFR part 97 shall be used to determine compliance by the unit with the NOx Budget emissions limitation under paragraph (c).

(c) Nitrogen oxides requirements.

(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 § 97.54(a), (b), (e), or (f) 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 H of 40 CFR part 97, plus any amount necessary to account for actual heat input under § 97.42(e) for the control period or to account for excess emissions for a prior control period under § 97.54(d) or to account for withdrawal from the NOx Budget Trading Program, or a change in regulatory status, of a NOx Budget opt-in unit under § 97.86 or § 97.87.
(2) Each ton of nitrogen oxides emitted in excess of the NOx Budget emissions limitation shall constitute a separate violation of 40 CFR part 97, the Clean Air Act, and applicable State law.
(3) A NOx Budget unit shall be subject to the requirements under paragraph (c)(1) 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 E, F, G, and I of 40 CFR part 97.
(5) A NOx allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1), 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 Administrator 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, the NOx Budget permit, or an exemption under § 97.4(b) or § 97.5 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) A NOx allowance allocated by the Administrator under the NOx Budget Trading Program does not constitute a property right.
(8) Upon recordation by the Administrator under subpart F or G of 40 CFR part 97, every allocation, transfer, or deduction of a NOx allowance to or from a NOx Budget unit's compliance account or the overdraft account of the source where the unit is located is incorporated automatically in any NOx Budget permit of the NOx Budget unit.

(d) Excess emissions requirements.

(1) The owners and operators of a NOx Budget unit that has excess emissions in any control period shall:
 (i) Surrender the NOx allowances required for deduction under § 97.54(d)(1); and
 (ii) Pay any fine, penalty, or assessment or comply with any other remedy imposed under § 97.54(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 permitting authority or the Administrator.
 (i) The account certificate of representation under § 97.13 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; 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 under § 97.13 changing the NOx authorized account representative.
 (ii) All emissions monitoring information, in accordance with subpart H of 40 CFR part 97; provided that to the extent that subpart H of 40 CFR part 97 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 D, H, or I of 40 CFR part 97.

Plant Name (from Step 1) **CPV Valley Energy Center**

(f) Liability.
(1) Any person who knowingly violates any requirement or prohibition of the NOx Budget Trading Program, a NOx Budget permit, or an exemption under § 97.4(b) or § 97.5 shall be subject to enforcement pursuant to applicable State or Federal law.
(2) Any person who knowingly makes a false material statement in any record, submission, or report under the NOx Budget Trading Program shall be subject to criminal enforcement pursuant to the applicable State or Federal law.
(3) 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.
(4) Each NOx Budget source and each NOx Budget unit shall meet the requirements of the NOx Budget Trading Program.
(5) Any provision of the NOx Budget Trading Program that applies to a NOx Budget source or 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 Budget units at the source.
(6) Any provision of the NOx Budget Trading Program that applies to a NOx Budget unit or 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 H of 40 CFR part 97, 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, a NOx Budget permit, or an exemption under § 97.4(b) or § 97.5 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 provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

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 **Steve Remillard**	
Signature	Date 11/24/08

Plant Name (from Step 1) **CPV Valley Energy Center**

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 permit application

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 I of 40 CFR part 97 is not a NOx Budget unit under 40 CFR 97.4(a) and is not covered by an exemption under 40 CFR part 97.4(b) or 97.5 that is in effect.

Name	
Signature	Date

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 I of 40 CFR part 97 is operating, as that term is defined under 40 CFR 97.2.

Name	
Signature	Date

ADR NOx Budget Permit Application

For more information, refer to 6 NYCRR Part 237-3.3

This submission is: ☒ New ☐ Revised

Has your Title V permit been modified to include 6 NYCRR Part 237? ☐ Yes ☐ No ... I will notify the regional DEC office that my Title V permit must be modified in order to include 6 NYCRR Part 237.

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

Plant Name	ORIS/Facility Code
CPV Valley Energy Center	56940

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 237-3.3 in accordance with the deadlines specified in Subdivision 237-3.2;
(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 237-8.
(2) The emissions measurements recorded and reported in accordance with Subpart 237-8 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

(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 237-6.5, 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 237-8.

(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 October 1, 2004 or the date on which the unit commences operation.
(4) NOx allowances shall be held in, deducted from, or transferred among New York State Acid Deposition Reduction Allowance Tracking System accounts in accordance with Subparts 237-5, 237-6, 237-7, and 237-9.
(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 ADR NOx Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the ADR NOx Budget Trading Program. No provision of the ADR 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 ADR 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 237-6.5(d)(1); and
(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed under Paragraph 237-6.5(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 its agent.

(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 237-2.4; 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 237-8; provided that to the extent that Subpart 237-8 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 ADR NOx Budget Trading Program.
(iv) Copies of all documents used to complete a NOx budget permit application and any other submission under the ADR NOx Budget Trading Program or to demonstrate compliance with the requirements of the ADR 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 ADR NOx Budget Trading Program, including those under Subparts 237-4, 237-8, or 237-9.

(f) Liability

(1) No permit revision shall excuse any violation of the requirements of the ADR NOx Budget Trading Program that occurs prior to the date that the revision takes effect.
(2) Any provision of the ADR 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 budget units at the source.
(3) Any provision of the ADR 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 237-8, 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 ADR 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	Steve Remillard
Signature	
Date	11/24/08
Company	CPV Valley, LLC
Street	50 Braintree Hill Office Park, Suite 300
City/State/Zip	Braintree, MA 02184
Phone	781-817-8970
Fax	781-848-5804
E-Mail	sremillard@cpv.com

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
	• •
	• •
	• •
	• •

STEP 5 (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 237-9 is operating, as that term is defined under 6 NYCRR 237-1.4.		
	Name		
	Signature		
	Date		

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
NYSDEC
ADR NOx Budget Trading Program
625 Broadway, 2nd Floor
Albany, NY 12233-3251

Please call NYSDEC Division of Air Resources at (518) 402-8396 with any questions.

Account Certificate of Representation NO_x

This form is required to establish an Authorized Account Representative for compliance accounts under the Acid Deposition Reduction (ADR) NO_x Budget Trading Program. For more information, see instructions.

This submission is: [X] New [ ] Revised

Check this box if you are also the Designated Representative for this plant under 6NYCRR Part 238: [X]

STEP 1
Identify the budget source(s) by plant name, State, and, if applicable, ORISPL code.

Plant Name: CPV Valley Energy Center	ORIS Code 56940

STEP 2
Enter requested information for the Authorized Account Representative (AAR).

Name: Steve Remillard	
Address: CPV Valley, LLC 50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184	
Phone Number: 781-817-8970	Fax Number: 781-848-5804
E-mail Address: sremillard@cpv.com	

STEP 3
Enter requested information for the Alternate Authorized Account Representative, if applicable.

Name	AAR ID Number (if known)
Phone Number	Fax Number
E-mail Address	

STEP 4
Provide the name of every owner and operator of the budget sources at the plant. Identify the budget sources they own and/or operate by boiler ID#.

Name: CPV Valley LLC				[X] Owner	[X] Operator
ID# 0001	ID# 0002	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#

Name				•• Owner	•• Operator
ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#

CPV Valley Energy Center
Plant Name (from Step 1)

Account Certificate of Representation - Page 2

STEP 5
Read the certification, sign and date.

I certify that I was selected as the NOx authorized account representative or alternate NOx authorized account representative, as applicable, by an agreement binding on the owners and operators of the NOx budget source and each NOx budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the ADR NOx Budget Trading Program on behalf of the owners and operators of the NOx budget source and of each NOx budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Department or a court regarding the source or unit.

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 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 (Authorized Account Representative)	11/24/08 Date
Signature (Alternate Authorized Account Representative)	Date

INSTRUCTIONS

Under the ADR NOx Budget Trading Program, the owners and operators for each budget source must designate a representative, and may designate an alternate, to act on their behalf. The owners and operators should choose the representative through a process that ensures that all owners and operators have notice regarding the selection. All budget sources at a plant must have the same Authorized Account Representative. The Authorized Account Representative is responsible for all submissions and allowance transactions relating to the budget sources at that plant. The Authorized Account Representative and the Alternate Authorized Account Representative are liable for acts or omissions within the scope of their responsibilities under the ADR NOx Budget Trading Program. The Department or its agent will not record an allowance transaction until it has received a complete Account Certificate of Representation.

Please type or print. If more space is needed, photocopy the first page. Indicate the page order and total number of pages (*e.g.*, 1 of 4, 2 of 4, etc.) *Note*: An Account Certificate of Representation amending an earlier submission supersedes the earlier submission *in its entirety*. A revised Account Certificate of Representation must therefore *be complete*, including signature and dating by the Authorized Account Representative (and the Alternate, if applicable).

Submit one Account Certificate of Representation form with *original* signatures. Remember that the Authorized Account Representative should notify each owner and operator of all NOx Budget Program submissions.

For assistance, call the NYSDEC, Division of Air Resources at (518) 402-8396.

STEP 1: If any NOx budget source at the plant is affected by the NOx Budget Trading Program (6 NYCRR Part 204), the ORISPL code is embedded in the first six digits of the unit account number for that source under the NOx Budget Trading Program.

STEP 2. The Authorized Account Representative must be a natural person and cannot be a company. Please enter the firm name and address as it should appear on all correspondence.

Note: All Department correspondence is mailed to the Authorized Account Representative only. An Alternate Authorized Account Representative must rely on the Authorized Account Representative to forward information mailed by the Department.

STEP 4 The owners and operators may be companies or natural persons. Identify each budget source at the plant that is owned or operated by the named party by providing the unit identification number for the budget source. If a budget source is affected by the NOx Budget Trading Program, the source should determine an appropriate ID# that it will use for all ADR Budget Trading Program purposes. This ID# must be six digits or less.

STEP 5 Note the certification statement.

SUBMISSION INSTRUCTIONS:

Submit this form prior to submission of the monitoring plan for the NOx Budget Trading Program. This form must be submitted before participating in transfers of allowances. Submit a revised Account Certificate of Representation when any information in the existing Account Certificate of Representation changes.

Mailing Instructions

Mail this form to the Department at the following address:

NYSDEC
ADRNOx Budget Trading Program.
625 Broadway
Albany, NY 12233-3251

Account Certificate of Representation

This form is required to establish an Authorized Account Representative for compliance accounts under the NOx Budget Trading Program. For more information, see instructions on the reverse side of the form.

This submission is: [X] New
[ ] Revised

Check this box if you are also the Designated Representative for this plant under the Acid Rain Program: [X]

STEP 1
Identify the budget source(s) by plant name, State, and, if applicable, ORISPL code.

Plant Name	State	ORIS Code
CPV Valley Energy Center	NY	56940

STEP 2
Enter requested information for the Authorized Account Representative (AAR).

Name: Steve Remillard	AAR ID Number (if known):
Address: CPV Valley, LLC 50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184	
Phone Number: 781-817-8970	Fax Number: 781-848-5804
E-mail Address (if available): sremillard@cpv.com	

STEP 3
Enter requested information for the Alternate Authorized Account Representative, if applicable.

Name:	AAR ID Number (if known):
Phone Number:	Fax Number:
E-mail Address (if available):	

STEP 4
Provide the name of every owner and operator of the budget sources at the plant. Identify the budget sources they own and/or operate by boiler ID#.

Name: CPV Valley, LLC				[X] Owner	[X] Operator
ID# 0001	ID# 0002	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#

Name:				• Owner	• Operator
ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#

CPV Valley Energy Center
Plant Name (from Step 1)

STEP 5
Read the certification, sign and date.

I certify that I was selected as the NOx authorized account representative or alternate NOx authorized account representative, as applicable, by an agreement binding on the owners and operators of the NOx Budget source and each NOx Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NOx Budget Trading Program on behalf of the owners and operators of the NOx Budget source and of each NOx Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit.

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 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 (Authorized Account Representative)	Date 11/24/08
Signature (Alternate Authorized Account Representative)	Date

INSTRUCTIONS

Under the state regulations to implement the NOx Budget Trading Program, the owners and operators for each budget source must designate a representative, and may designate an alternate, to act on their behalf. The owners and operators should choose the representative through a process that ensures that all owners and operators have notice regarding the selection. All budget sources at a plant must have the same Authorized Account Representative. The Authorized Account Representative is responsible for all submissions and allowance transactions relating to the budget sources at that plant. The Authorized Account Representative and the Alternate Authorized Account Representative are liable for acts or omissions within the scope of their responsibilities under the NOx Budget Trading Program. EPA will not record an allowance transaction until it has received a complete Account Certificate of Representation.

Please type or print. If more space is needed, photocopy the first page. Indicate the page order and total number of pages (*e.g.*, 1 of 4, 2 of 4, etc.). *Note*: An Account Certificate of Representation amending an earlier submission supersedes the earlier submission *in its entirety*. A revised Account Certificate of Representation must therefore *be complete*, including signature and dating by the Authorized Account Representative (and the Alternate, if applicable).
Submit one Account Certificate of Representation form with *original* signatures. Remember that the Authorized Account Representative should notify each owner and operator of all NOx Budget Program submissions.
For assistance, call the EPA's Clean Air Markets Division Hotline at (202) 343-9620.
STEP 1: If any budget source at the plant is affected by the Acid Rain Program, the ORISPL code is embedded in the first six digits of the unit account number for that source under the Acid Rain Program. If there are not any budget sources at the plant affected by the Acid Rain Program, a budget source should use the plant or facility code registered with the Department of Energy (DOE) to obtain an ORISPL code. (For utilities reporting on the EIA-767, -860, and -861, the plant code would be used as the ORISPL code. For nonutilities reporting on the EIA-867, the facility code would be used as the (ORISPL code). If the budget source does not report to DOE, and therefore does not have an ORISPL code, the budget source should call the Acid Rain Program Hotline for assistance.
STEP 2: The Authorized Account Representative must be a natural person and cannot be a company. Please enter the firm name and address as it should appear on all correspondence.

EPA Form 7620-16
Representative must rely on the Authorized Account Representative to forward information mailed by EPA.

STEP 4 The owners and operators may be companies or natural persons. Identify each budget source at the plant that is owned or operated by the named party by providing the unit identification number for the budget source. If a budget source is affected by the Acid Rain Program, the source should determine an appropriate ID# that it will use for all NOx Budget Trading Program purposes. This ID# must be six digits or less.
STEP 5 Note the certification statement.

SUBMISSION INSTRUCTIONS:

Submit this form prior to submission of the monitoring plan for the NOx Budget Trading Program. This form must be submitted before participating in transfers of allowances.
Submit a revised Account Certificate of Representation when any information in the existing Account Certificate of Representation changes.

Mailing Instructions

Mail this form to EPA at one of the following addresses:
U.S. EPA
NOx Budget Trading Program (6204J)

for regular or certified mail:	for overnight mail:
1200 Pennsylvania Ave. NW	1310 L Street. NW
Washington. DC 20460	Washington. DC 20005

Phone: 202-343-9620

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average30 hours per response . Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

ADR SO_2 Budget Permit Application

For more information, refer to 6 NYCRR Part 238-3.3

This submission is: ☒ New ☐ Revised

Has your Title V permit been modified to include 6 NYCRR Part 238? ☐ Yes ☐ No ... **I will notify the regional DEC office that my Title V permit must be modified in order to include 6 NYCRR Part 238.**

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

Plant Name	ORIS/Facility Code
CPV Valley Energy Center	56940

STEP 2
Enter the unit ID# for each SO_2 budget unit

Unit ID#

0001					
0002					

STEP 3
Read the standard requirements and the certification, enter the name of the SO_2 authorized account representative, and sign and date

Standard Requirements

(a) Permit Requirements

(1) The SO_2 authorized account representative of each SO_2 budget unit shall:

(i) Submit to the Department a complete SO_2 budget permit application under Section 238-3.3 in accordance with the deadlines specified in Subdivision 238-3.2;

(ii) Submit in a timely manner any supplemental information that the Department determines is necessary in order to review a SO_2 budget permit application and issue or deny a SO_2 budget permit.

(2) The owners and operators of each SO_2 budget unit shall have a SO_2 budget permit and operate the unit in compliance with such SO_2 budget permit.

(b) Monitoring requirements

(1) The owners and operators and, to the extent applicable, the SO_2 authorized account representative of each SO_2 Budget source and each SO_2 budget unit at the source shall comply with the monitoring requirements of Subpart 238-8.

(2) The emissions measurements recorded and reported in accordance with Subpart 238-8 shall be used to determine compliance by the unit with the SO_2 budget emissions limitation under subdivision (c) of this section.

(c) Sulfur Dioxide requirements

(1) The owners and operators of each SO_2 budget source and each SO_2 budget unit at the source shall hold SO_2 allowances available for compliance deductions under Section 238-6.5, as of the SO_2 allowance transfer deadline, in the unit's compliance account and the source's overdraft account in an amount not less than the total SO_2 emissions for the control period from the unit, as determined in accordance with Subpart 238-8.

(2) Each ton of sulfur dioxide emitted in excess of the SO_2 budget emissions limitation shall constitute a separate violation of this Part, the Clean Air Act and applicable State law.
(3) A SO_2 budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of October 1, 2004 or the date on which the unit commences operation.
(4) SO_2 allowances shall be held in, deducted from, or transferred among New York State Acid Deposition Reduction Allowance Tracking System accounts in accordance with Subparts 238-5, 238-6, and 238-7.
(5) A SO_2 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 SO_2 allowance was allocated.
(6) A SO_2 allowance allocated by the Department under the ADR SO_2 Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the ADR SO_2 Budget Trading Program. No provision of the ADR SO_2 Budget Trading Program, the SO_2 budget permit application, or the SO_2 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 SO_2 allowance allocated by the Department under the ADR SO_2 Budget Trading Program does not constitute a property right.

(d) Excess emissions requirements

The owners and operators of a SO_2 budget unit that has excess emissions in any control period shall:
(1) Forfeit the SO_2 allowances required for deduction under Paragraph 238-6.5(d)(1); and
(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed under Paragraph 238-6.5(d)(3).

(e) Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the SO_2 budget source and each SO_2 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 its agent.

> (i) The account certificate of representation for the SO_2 authorized account representative for the source and each SO_2 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 238-2.4; 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 SO_2 authorized account representative.
> (ii) All emissions monitoring information, in accordance with Subpart 238-8; provided that to the extent that Subpart 238-8 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 ADR SO_2 Budget Trading Program.
> (iv) Copies of all documents used to complete a SO_2 budget permit application and any other submission under the ADR SO_2 Budget Trading Program or to demonstrate compliance with the requirements of the ADR SO_2 Budget Trading Program.

(2) The SO_2 authorized account representative of a SO_2 budget source and each SO_2 budget unit at the source shall submit the reports and compliance certifications required under the ADR SO_2 Budget Trading Program, including those under Subparts 238-4, or 238-8.

(f) Liability

(1) No permit revision shall excuse any violation of the requirements of the ADR SO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.
(2) Any provision of the ADR SO_2 Budget Trading Program that applies to a SO_2 budget source (including a provision applicable to the SO_2 authorized account representative of a SO_2 budget source) shall also apply to the owners and operators of such source and of the SO_2 budget units at the source.
(3) Any provision of the ADR SO_2 Budget Trading Program that applies to a SO_2 budget unit (including a provision applicable to the SO_2 authorized account representative of a SO_2 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 238-8, the owners and operators and the SO_2 authorized account representative of one SO_2 budget unit shall not be liable for any violation by any other SO_2 budget unit of which they are not owners or operators or the SO_2 authorized account representative and that is located at a source of which they are not owners or operators or the SO_2 authorized account representative.

(g) Effect on Other Authorities

No provision of the ADR SO_2 Budget Trading Program, a SO_2 budget permit application, or a SO_2 budget permit, shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the SO_2 authorized account representative of a SO_2 budget source or SO_2 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 SO_2 budget sources or SO_2 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	Steve Remillard
Signature	S. P. R
Date	11/24/08
Company	CPV Valley, LLC
Street	50 Braintree Hill Office Park, Suite 300
City/State/Zip	Braintree, MA 02184
Phone	781-817-8970
Fax	781-848-5804
E-Mail	sremillard@cpv.com

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
NYSDEC
ADR SO_2 Budget Trading Program
625 Broadway, 2nd Floor
Albany, NY 12233-3251

Please call NYSDEC Division of Air Resources at (518) 402-8396 with any questions.

Account Certificate of Representation SO_2

This form is required to establish an Authorized Account Representative for compliance accounts under the Acid Deposition Reduction (ADR) SO_2 Budget Trading Program, 6 NYCRR Part 238. For more information, see instructions.

This submission is: [X] New [ ] Revised

Check this box if you are also the Designated Representative for this plant under 6NYCRR Part 237: [X]

STEP 1
Identify the budget source(s) by plant name, and, if applicable, ORISPL code.

Plant Name CPV Valley Energy Center	ORIS Code 56940

STEP 2
Enter requested information for the Authorized Account Representative (AAR).

Name Steve Remillard	AAR ID Number (if known)
Address CPV Valley, LLC 50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184	
Phone Number 781-817-8970	Fax Number 781-848-5804
E-mail Address sremillard@cpv.com	

STEP 3
Enter requested information for the Alternate Authorized Account Representative, if applicable.

Name	AAR ID Number (if known)
Phone Number	Fax Number
E-mail Address	

STEP 4
Provide the name of every owner and operator of the budget sources at the plant. Identify the budget sources they own and/or operate by boiler ID#.

Name CPV Valley, LLC				[X] Owner	[X] Operator
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#

Name				•• Owner	•• Operator
ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#

CPV Valley Energy Center
Plant Name (from Step 1)

Account Certificate of Representation - Page 2

STEP 5
Read the certification, sign and date.

I certify that I was selected as the SO_2 authorized account representative or alternate SO_2 authorized account representative, as applicable, by an agreement binding on the owners and operators of the SO_2 budget source and each SO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the ADR SO_2 Budget Trading Program on behalf of the owners and operators of the SO_2 budget source and of each SO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Department or a court regarding the source or unit.

I am authorized to make this submission on behalf of the owners and operators of the SO_2 budget sources or SO_2 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 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 (Authorized Account Representative)	Date 11/24/08
Signature (Alternate Authorized Account Representative)	Date

INSTRUCTIONS

Under the ADR SO_2 Budget Trading Program, the owners and operators for each budget source must designate a representative, and may designate an alternate, to act on their behalf. The owners and operators should choose the representative through a process that ensures that all owners and operators have notice regarding the selection. All budget sources at a plant must have the same Authorized Account Representative. The Authorized Account Representative is responsible for all submissions and allowance transactions relating to the budget sources at that plant. The Authorized Account Representative and the Alternate Authorized Account Representative are liable for acts or omissions within the scope of their responsibilities under the ADR SO_2 Budget Trading Program. The Department or its agent will not record an allowance transaction until it has received a complete Account Certificate of Representation.

Please type or print. If more space is needed, photocopy the first page. Indicate the page order and total number of pages (*e.g.*, 1 of 4, 2 of 4, etc.). *Note*: An Account Certificate of Representation amending an earlier submission supersedes the earlier submission *in its entirety*. A revised Account Certificate of Representation must therefore *be complete*, including signature and dating by the Authorized Account Representative (and the Alternate, if applicable).

Submit one Account Certificate of Representation form with *original* signatures. Remember that the Authorized Account Representative should notify each owner and operator of all SO_2 Budget Program submissions.

For assistance, call the NYSDEC, Division of Air Resources at (518) 402-8396.

STEP 1: If any SO_2 budget source at the plant is affected by the NOx Budget Trading Program (6 NYCRR Part 204), the ORISPL code is embedded in the first six digits of the unit account number for that source under the NOx Budget Trading Program.

STEP 2: The Authorized Account Representative must be a natural person and cannot be a company. Please enter the firm name and address as it should appear on all correspondence.

Note: All Department correspondence is mailed to the Authorized Account Representative only. An Alternate Authorized Account Representative must rely on the Authorized Account Representative to forward information mailed by the Department.

STEP 4 The owners and operators may be companies or natural persons. Identify each budget source at the plant that is owned or operated by the named party by providing the unit identification number for the budget source. If a budget source is affected by the NOx Budget Trading Program, the source should determine an appropriate ID# that it will use for all ADR Budget Trading Program purposes. This ID# must be six digits or less.

STEP 5 Note the certification statement.

SUBMISSION INSTRUCTIONS:

Submit this form prior to submission of the monitoring plan for the SO_2 Budget Trading Program. This form must be submitted before participating in transfers of allowances. Submit a revised Account Certificate of Representation when any information in the existing Account Certificate of Representation changes.

Mailing Instructions

Mail this form to the Department at the following address:

NYSDEC
ADR SO_2 Budget Trading Program.
625 Broadway
Albany, NY 12233-3251

APPENDIX E

RACT/BACT/LAER CLEARINGHOUSE AND RECENT AIR PERMIT SEARCH

Appendix E: Table E-1
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	SCR	2.0	BACT
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	DLN, SCR AND GCP	2.0	BACT
FP&L TURKEY POINT FOSSIL PLANT - UNIT 5	HOMESTEAD, FL	6/1/2004	NO	(4) COMBUSTION TURBINE W/ DB, W/ POWER AUG, &/OR CT ONLY	2,103	SCR WITH DLN	2.0	BACT-OTHER
VINEYARD ENERGY CENTER, LLC	VINEYARD, UT	5/11/2004	NO	(3) SWPC 501F COMBUSTION TURBINES	1,738	DLN AND SCR	2.0	BACT
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) COMBINED CYCLE TURBINES	2,160	DLN AND SCR	2.0	LAER
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	DLN AND SCR	2.0	OTHER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	SCR AND DLN	2.0	LAER
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	SCR	2.0	OTHER
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	DLN AND SCR	2.0	LAER
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	DLN AND SCR	2.0	LAER
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	LOW-NOx COMBUSTORS	2.0	BACT-OTHER
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	SCR AND LOW NOX COMBUSTORS	2.0	BACT-PSD
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	SCR	2.0	LAER
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	(2) TURBINE, COMBINED CYCLE W/ AND W/O DUCT BURNER	1,955	SCR	2.0	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	LNB, WATER INJECTION AND SCR	2.0	BACT
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES	1,611	SCR	2.0	LAER
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	LNB AND SCR	2.0	BACT
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	YES	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS	1,965	SCR WITH AMMONIA INJECTION	2.0	LAER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	SCR	2.0	LAER
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	SCR, DLN COMBUSTORS	2.0	LAER
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	SCR	2.0	BACT-PSD
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	?	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	DLN COMBUSTORS AND SCR	2.0	BACT-OTHER
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	YES	TURBINE, COMBINED CYCLE	1,456	SCR AND DRY LNB	2.0	LAER
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	NO	(3) TURBINE, COMBINED CYCLE	1,467	DLN AND SCR	2.0	LAER
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	SCR	2.0	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	GE ADVANCED DRY-LOW NOX COMBUSTORS + SCR	2.0	BACT-PSD
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	LNB,S SCR AND GCP	2.0	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	DLN BURNERS, SCR	2.0	BACT-PSD
MIRANT BOWLINE LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	DLN AND SCR	2.0	LAER
				(3) COMBINED CYCLE TURBINES	2,049		2.9	
CONED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	SCR AND DLN	2.0	LAER
				(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		3.0	
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	DLN AND SCR	2.0	OTHER
				(1) COMBINED CYCLE COMBUSTION TURBINE, W/ DUCT BURNER	2,423		3.1	
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	?	(2) TURBINE, COMBINED CYCLE	1,815	SCR	2.0	LAER
				(2) TURBINE, COMBINED CYCLE, W/ STEAM INJECTION	1,815		3.5	
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYCLE	3,630	SCR	2.0	LAER
				(2) TURBINES, COMBINED CYCLE, W/ STEAM INJECTION	3,630		3.5	
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	(2) SIEMENS SGT6-5000F CTGs (NG FIRED) W/ DB	2,205	LNB AND SCR	2.0	LAER
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 1	1,717	2 STAGE PREMIX NOX COMBUSTION AND SCR	2.0	BACT-PSD
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 3	2,204	2 STAGE LEAN PREMIX AND GCP, SCR	2.0	BACT-PSD
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 2"	1,944	GCP. 2 STAGE LEAN PREMIX AND SCR.	2.0	BACT-PSD
ATHENS GENERATING PLANT	GREENE, NY	1/19/2007	NO	FUEL COMBUSTION (GAS)	3,100	DLN AND GAS FIRING, SCR W/ NAOH INJECTION	2.0	LAER
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/16/2005	?	TURBINE, COMBINED CYCLE COMBUSTION #1 W/ HRSG & DB	2,448	SCR W/ AMMONIA INJECTION	2.0	BACT-PSD
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/17/2005	?	TURBINE, COMBINED CYCLE COMBUSTION #2 W/ HRSG & DB	2,448	SCR W/ AMMONIA INJECTION	2.0	BACT-PSD
EMPIRE POWER PLANT	RENSSELAER, NY	6/23/2005	?	FUEL COMBUSTION (NATURAL GAS)	2,099	DLN IN COMBINATION W/ SCR	2.0	LAER
ISLAND END-CABOT POWER	BOSTON, MA	2000	NO		2,800	SCR	2.0	LAER
HERITAGE STATION	SCRIBA NY	10/12/2000	NO		6,400	SCR	2.0	LAER
BOWLINE POINT UNIT 3	NEW YORK	2001	NO		6,000	DLN,SCR	2.0	LAER
RAVENSWOOD COGENERATION FACILITY	LONG ISLAND CITY, NY	2001	NO		2,000	DLN,SCR	2.0	LAER
SITHE MYSTIC DEVELOPMENT LLC	EVERETT, MA	1/25/2000	NO			SCR	2.0	STATE BACT
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	SCR	2.2	BACT-PSD
FREE STATE ELECTRIC	MARYLAND	9/27/2001	NO			DRY LOW Nox., SCR	2.5	BACT
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	DLN + SCR	2.5	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE	1,844	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	DLN AND SCR	2.5	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	DLN AND SCR	2.5	BACT
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	DLN AND SCR	2.5	BACT
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	YES	COMBINED CYCLE NATURAL GAS	2,362	SCR	2.5	BACT-OTHER
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	YES	TURBINE, COMBINED CYCLE	2,040	SCR	2.5	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	SCR AND LNB	2.5	BACT-PSD
KYRENE GENERATING STATION, SALT RIVER	PHOENIX, AZ	3/14/2001	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	SCR	2.5	LAER
MOUNTAINVIEW POWER	SAN BERNARDINO, CA	5/22/2001	YES	(4) TURBINE, COMBINED CYCLE	1,991	SCR	2.5	LAER
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	SCR W/ AMMONIA INJECTION	2.5	LAER
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	SCR PLUS LEAN PREMIX DLN LNB	2.5	BACT
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,680	DLN PLUS SCR WET INJECTION	2.5	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,680	DLN, SCR, WET INJECTION	2.5	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE, W/ AND W/O DB	1,600	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYLE, W/ AND W/O DB	1,600	DLN COMBUSTORS WITH SCR	2.5	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	DLN COMBUSTORS & SCR	2.5	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	LNB, SCR	2.5	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	LNB, SCR	2.5	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	DLN COMBUSTOR AND SCR SYSTEM	2.5	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	SCR	2.5	LAER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	SCR AND DLN BURNERS	2.5	LAER
CAROLINA POWER & LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	DLN AND SCR	2.5	BACT-PSD
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	DLN AND SCR	2.5	BACT-PSD
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE W/ AND W/O DB (GE, MHI, SW)	1,400	DLN AND SCR	2.5	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	LNB WITH SCR	2.5	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LNB WITH SCR	2.5	BACT-PSD

Appendix E: Table E-1
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE, W/ AND W/O DB	2,964	SCR - AMMONIA FLOW RATE AT 11.46 GAL/H	2.5	OTHER
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE (60%-100% LOAD) W/ AND W/O DB	2,181	SCR - 29% AQUEOUS AMMONIA, DLN	2.5	OTHER
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	?	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	SCR, DLN COMBUSTION AND GCP	2.5	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	DLN COMBUSTORS, AND SCR	2.5	BACT-PSD
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	DLN COMBUSTION, SCR	2.5	BACT-PSD
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	SCR	2.5	LAER
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	SCR, DLN COMBUSTION	2.5	LAER
CONECTIV BETHLEHEM, INC.	PENNSYLVANIA	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	SCR, DLN COMB, CLEAN FUEL WI NG DIFFUSION MODE	2.5	LAER
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	?	(2) TURBINE, COMBINED CYCLE	2,240	LNB, SCR	2.5	LAER
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	DLN BURNERS WITH SCR	2.5	BACT-PSD
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	DLN & SCR	2.5	LAER
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	LEAN PRE-MIX DLN AND GCP. SCR SYSTEM AND CEM	2.5	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	2,325	DLN BURNERS SCR W/ CEM DEVICES	2.5	BACT-PSD
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	2,470	SCR AND LNB. GCP	2.5	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	SCR	2.5	BACT-OTHER
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	SCR	2.5	BACT-OTHER
BLACK HILLS CORP./NEIL SIMPSON TWO	GILLETTE, WY	4/4/2003	?	TURBINE, COMBINED CYCLE & DUCT BURNER	320	DLN BURNERS AND SCR	2.5	BACT-OTHER
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	SCR	2.5	BACT-PSD
				TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,923		3.1	
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	DLN COMBUSTION AND SCR W/CEM	2.5	BACT-PSD
				(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		3.3	
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	THE USE OF DLN COMBUSTOR AND SCR	2.5	BACT-PSD
				(4) COMBUSTION TURBINE COMBINED CYCLE, W/ STEAM INJ	2,010		3.5	
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	LNB AND GCP. SCR USING AMMONIA INJECTION. CEM	2.5	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, 70% LOAD	1,492		4.5	
HINES POWER BLOCK 4	POLK, FL	6/8/2005	?	COMBINED CYCLE TURBINE	4,240	SCR	2.5	BACT-PSD
SEPCO	RIO LINDA, CA	10/5/1994	?	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920	SCR AND DLN COMBUSTION	2.6	BACT
EMPIRE POWER PLANT	RENSSELAER, NY	6/23/2005	?	FUEL COMBUSTION (NATURAL GAS) DUCT BURNING	646	DLN IN COMBINATION W/ SCR	3.0	LAER
S.W.E.C, LLC	FALLS TWP, PA	2001	NO				3.0	LAER
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO, CA	8/19/1994	YES	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	1,257	SCR AND DRY LOW NOX COMBUSTION	3.0	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,876	SCR AND DLN	3.0	BACT-PSD
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	SCR	3.0	BACT-PSD
SALT RIVER/DESERT BASIN GENERATING PROJECT	PHOENIX, AZ	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	SCR	3.0	BACT-PSD
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO, CA	8/19/1994	?	TURBINE, GAS COMBINED CYCLE LM6000	421	SCR AND WATER INJECTION	3.0	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO, CA	8/19/1994	?	TURBINE GAS COMBINE CYCLE SIEMENS V84.2	1,257	SCR AND DLN COMBUSTION	3.0	BACT
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	YES	(2) COMBINED-CYCLE TURBINE	2,311	LN COMB (POLLUTION PREVENTION) AND SCR (CONTROL)	3.0	BACT-PSD
AUGUSTA ENERGY CENTER	GEORGIA	10/28/2001	YES	(3) TURBINE, COMBINED CYCLE	2,000	SCR	3.0	BACT-PSD
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	LNB AND SCR	3.0	BACT-PSD
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	DLN BURNERS AND SCR	3.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE, GA	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	DLN COMBUSTORS SCR	3.0	
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	YES	(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400	SCR WITH DLN COMBUSTION	3.0	BACT-PSD
ROQUETTE AMERICA	KEOKUK, IA	1/31/2003	?	TURBINE, COMBINED CYCLE	587	SCR	3.0	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	SCR	3.0	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	SCR	3.0	BACT-PSD
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION, W/ AND W/O DB	1,735	SCR (80-90%), DLN BURNERS AND GCP	3.0	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE, W/ AND W/O DB	1,944	DLN BURNERS AND GOOD COMBUSTION: SCR	3.0	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,491	DLN BURNERS AND SCR. NATURAL GAS IS ONLY FUEL	3.0	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	YES	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	SCR AND LNB	3.0	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	YES	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883	DLN BURNERS AND SCR	3.0	BACT-PSD
CONTINENTAL ENERGY SVC, SILVER BOW GEN	BUTTE, MT	6/7/2002	NO	(4) COMBINED CYCLE CT	1,400	SCR	3.0	BACT-PSD
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON/OFF	1,440	DLN & LNB & SCR	3.0	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	YES	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON/OFF	1,376	DLN BURNERS AND SCR	3.0	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	DLN BURNERS, SCR	3.0	LAER
RELIANT ENERGY- CHANNELVIEW COGEN	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	3.0	
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	SCR	3.0	LAER
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	SCR SYSTEM UNIT	3.0	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	SCR, CEM	3.0	BACT-PSD
TRANSALTA CENTRALIA GENERATION LLC	CENTRALIA, WA	2/22/2002	?	(4)TURBINE/HRSG	1,504	WATER INJECTION AND SCR	3.0	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	ADVANCED DLN TECHNOLOGY AND SCR	3.0	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	7/25/2001	YES	(2) GAS TURBINES COMBINED CYCLE	2,205	DLN STAGED COMB SCR MODE: W/ STEAM INJECTION	3.0	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE	2,200	DLN BURNERS AND SCR	3.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200		3.5	
HAY ROAD POWER COMPLEX UNITS 5-8	WILMINGTON, DE	10/17/2000	YES	TURBINES (3) COMBINED CYCLE NG PREMIXED MODE, BASELOAD	1,333	DLN BURNERS WITH SCR	3.0	LAER
				TURBINES (3) COMBINED CYCLE NG PREMIXED MODE, PEAKLOAD	1,333		9.0	
				TURBINES (3) COMBINED CYCLE NG DIFFUSION MODE	1,333		14.0	
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMB WITH SCR ADD-ON NOX CONTROL	3.1	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	SCR & DLN	3.1	BACT-OTHER
SOUTHERN ENERGY, INC.	ZEELAND, MI	3/16/2000	NO	COMBINED CYCLE TURBINE ELECTRICAL GENERATING UNITS		SELECTIVE CATALYTIC REDUCTION (SCR)	3.5	BACT-PSD
PIKE GENERATION FACILITY	MCCOMB, MS	11/14/2000	NO			DLN, SCR	3.5	BACT-PSD
CPV GULFCOAST LTD	MANATEE CO, FL	2/6/2001	NO			SCR	3.5	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMB WITH SCR ADD-ON NOX CONTROL	3.5	BACT-PSD
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	NO	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000	NONE INDICATED	3.5	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	DLN W/SCR	3.5	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	ALABAMA	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	DLN COMBUSTION & SCR	3.5	BACT-PSD
DUKE ENERGY DALE, LLC	ALABAMA	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	DLN AND SCR	3.5	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	ALABAMA	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	SCR	3.5	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	DLN COMBUSTORS + SCR	3.5	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	SCR/DLN	3.5	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	DLN BURNERS AND SCR	3.5	BACT-PSD
HOT SPRINGS POWER PROJECT	ARKANSAS	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	DLN BURNERS W/ SCR	3.5	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	ARKANSAS	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	SCR AND DLN COMBUSTORS	3.5	BACT-PSD

Appendix E: Table E-1
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	SCR	3.5	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (GE, SWH OR MHI)	1,360	DLN COMBUSTOR/SCR	3.5	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,696	DLN BURNERS	3.5	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	DLN WET INJECTION	3.5	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	DLN COMBUSTORS & SCR	3.5	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	SCR (DLN 2.6). WET INJECTION	3.5	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA, FL	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	SCR	3.5	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	DLN BURNERS	3.5	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	GOOD COMBUSTION AND SCR	3.5	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	DUCT BURNER, SCR	3.5	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD, ME	5/1/1998	YES	TURBINE GENERATOR COMBUSTION	1,906	SCR	3.5	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	SCR	3.5	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	DLN BURNERS AND SCR	3.5	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE, W/ AND W/O DB	2,096	DLN BURNER AND SCR	3.5	BACT-PSD
INDECK-NILES, LLC	NILES, MI	12/2/2001	?	(4) GAS TURBINES COMBINED CYCLE, W/ AND W/O DB	2,152	LNB AND SCR	3.5	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	DLN BURNERS STAGED COMB OF NATURAL GAS + SCR	3.5	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	DLN COMBUSTORS + SCR	3.5	BACT-PSD
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	SCR	3.5	BACT-PSD
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	LNB AND SCR UNIT	3.5	BACT-PSD
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	DLN BURNERS AND SCR	3.5	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	DLN COMBUSTORS, SCR	3.5	BACT-PSD
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	NO	(2) TURBINE, COMBINED CYCLE	640	LNB AND SCR	3.5	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	SCR AND COMBUST ONLY PIPELINE QUALITY NATURAL GAS	3.5	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE W/ AND W/O DUCT FIRING	1,360	DLN COMBUSTION BURNERS AND SCR	3.5	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,360	DLN COMBUSTION BURNERS AND SCR	3.5	BACT-PSD
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DB	2,440	SCR WITH DLN COMBUSTION	3.5	BACT-PSD
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/ AND W/O DB	1,440	SCR AND DLN BURNERS	3.5	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/ AND W/O DB	1,374	SCR AND DLN BURNERS	3.5	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	COMBUSTION TURBINE & DUCT BURNERS (GE OR MHI)	1,705	SCR WITH DLN COMBUSTORS	3.5	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	SCR, DLN COMBUSTORS	3.5	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	SCR WITH DLN BURNERS	3.5	BACT-PSD
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	?	(3) TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,798	DLN COMBUSTION TECHNOLOGY AND SCR	3.5	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000	DLN COMBUSTORS, SCR	3.5	LAER
LOWER MOUNT BETHEL ENERGY, LLC	FAIRFAX	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	SCR, DLN LEAN BURN COMBUSTORS	3.5	LAER
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	DLN LEAN BURNERS & SCR	3.5	LAER
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNERS, SCR	3.5	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TENNESSEE	2/1/2002	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,990	DLN BURNERS, SCR	3.5	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	SCR AND LNB	3.5	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	SCR	3.5	LAER
CHANNEL ENERGY FACILITY	HOUSTON, TX	3/22/2000	?	(3) TURBINE	1,440	SCR	3.5	LAER
CHAMBERS ENERGY L.P./AMERICAN NATIONAL POWER	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	DLN COMBUSTORS AND SCR SYSTEM H2O INJECTION	3.5	LAER
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	DLN COMBUSTION AND SCR	3.5	LAER
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	SCR, DLN BURNERS	3.5	LAER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACK	1,400	SCR	3.5	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	SCR	3.5	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	DLN COMBUSTORS & SCR	3.5	BACT-OTHER
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,937	WATER INJECTION SCR AND CEM	3.5	LAER
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION + SCR ADD-ON NOX CONTROLS	3.5	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	LNB + SCR	3.5	BACT-PSD
				(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DB	1,900		3.7	
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	DLN BURNERS AND SCR	3.5	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		4.4	
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	DLN COMBUSTOR & SCR NOX CONTROL	3.6	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	CLEAN BURNERS AND SCR	3.6	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	DLN BURNERS AND SCR	3.6	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	DLN BURNER AND SCR	3.6	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	DLN AND SCR	3.6	BACT-PSD
BEAR MOUNTAIN LIMITED	BAKERSFIELD, CA	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	STEAM INJECTION AND SCR	3.6	BACT-OTHER
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	DLN BURNER & SCR ON TURBINE. LNB ON DUCT BURNER	4.0	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	DLN COMBUSTION AND SCR USING AMMONIA INJECTION	4.0	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	SCR OF NOX	4.0	BACT-OTHER
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224	DRY LNB WITH SCR	4.0	LAER
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	LNB, SCR	4.0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	5/31/1994	YES	TURBINES, NATURAL GAS (2)	1,720	SCR	4.5	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO, NY	11/24/1992	YES	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133	SCR AND DRY LOW NOX	4.5	BACT-OTHER
FAIRBAULT ENERGY PARK	RICE, MN	6/5/2007		COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	1,758	DLN COMBUSTION FOR NG; WATER INJ FOR OIL; SCR	4.5	BACT-PSD
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	LNB, SCR	4.5	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	SCR	4.5	BACT-OTHER
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	DLN BURNERS AND SCR	4.5	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	SCR WITH A NOX CEM AND A NOX PEM	4.5	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GEN STATION	BURNSVILLE, MN	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	DLN COMBUSTORS PLUS SCR	4.5	95.9
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	DLN BURNERS, SCR	4.5	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	DLN COMBUSTOR	4.5	BACT-PSD
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	DRY COMBUSTION CONTROLS AND SCR	4.5	BACT-PSD
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	(2) COMBUSTION TURBINES #1 & #2	1,836	SCR	4.5	BACT-PSD
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	LNB, AND/OR SCR GOOD OPER & NATURAL GAS AS FUEL	4.5	BACT-PSD
				(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		12.5	
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	NO	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	SCR, LOW NOX COMBUSTORS	4.5	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166		15.0	
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	DLN COMBUSTOR IN CT LNB IN DUCT BURNER, SCR	4.9	BACT-PSD

Appendix E: Table E-1
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
CROCKETT COGENERATION - C&H SUGAR	CROCKETT, CA	10/5/1993	YES	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	1,920	DRY LOW-NOX COMBUSTERS AND A MITSUBISHI HEAVY INDUSTRIES AMERICAN SELECTIVE CATALYTIC REDUCTION CATALYST.	5.0	BACT-OTHER
GEISMAR PLANT	GEISMAR, LA	2/26/2002	?	(2) COGENERATION UNITS W/ AND W/O DB	320	LNB AND A SCR SYSTEM	5.0	BACT-PSD
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	DLN BURNERS, SCR	5.0	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	SCR & DLN BURNERS	5.0	BACT-PSD
SAM RAYBURN GENERATION STATION	NURSERY	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	SCR AND GOOD COMBUSTION"	5.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(6) GAS FUELED TURBINES, STACK 1-6	2,200	SCR, DLN BURNERS	5.0	BACT-PSD
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE W/ AND W/O POWER AUGMENTATION	2,000	DLN COMBUSTORS & SCR	5.0	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	DLN BURNERS & SCR SYSTEM	5.0	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	DLN BURNERS, FIRING WITH NATURAL GAS, USE OF SCR	5.0	BACT-PSD
				(4) GAS TURBINES TURBINE ONLY FIRING	1,360		9.0	
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	SCR & DLN COMBUSTORS	5.1	BACT-PSD
BRIDGEPORT ENERGY, LLC	BRIDGEPORT, CT	6/29/1998	YES	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	2,080	DRY LOW NOX BURNER WITH SCR	6.0	BACT-PSD
HERMISTON POWER PARTNERSHIP	OREGON	4/13/1999	?	(2) TURBINE	1,853	SCR	6.0	OTHER
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	SCR AND DLN BURNERS	6.0	BACT-OTHER
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	TURBINE/HRSG (CG-3)	1,280	SCR, DLN COMBUSTORS	6.0	LAER
				TURBINE/HRSG (CG-2)	1,280		9.0	
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	STEAM/WATER INJECTION AND SCR	7.0	BACT-PSD
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	SCR	7.5	BACT
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	STEAM INJECTION AND SCR	8.0	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TWP, NJ	4/1/1991	YES	TURBINES (NATURAL GAS) (2)	1190	SCR, DRY LOW NOX BURNER	8.9	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP	VA	5/4/1990	YES	TURBINE, COMBUSTION	1261	DRY COMBUSTOR TO 25 PPM SCR TO 9 PPM USING NAT GAS	9.0	OTHER
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	FL	10/15/1999	NO	TURBINE-GAS, COMBINED CYCLE	4,000	DLN GE DLN2.6 BURNERS	9.0	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN, GA	4/3/1996	YES	COMBUSTION TURBINE (2), NATURAL GAS	928	SCR	9.0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE, RI	4/13/1992	YES	TURBINE, GAS AND DUCT BURNER	1,360	SCR	9.0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	YES	TURBINE, COMBUSTION GAS (150 MW)	1,146	DRY LOW NOX	9.0	BACT-OTHER
SARANAC ENERGY COMPANY	PLATTSBURGH, NY	7/31/1992	YES	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123	SCR	9.0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK, NY	6/18/1992	YES	COMBUSTION TURBINES (2) (252 MW)	1,173	STEAM INJECTION AND SCR	9.0	BACT-OTHER
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	?	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	DLN BURNER ON TURBINE AND LNB ON DUCT BURNER	9.0	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	DLN GE DLN2.6 BURNERS	9.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	DLN 2.6 GE ADVANCED DLN BURNERS	9.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	DLN TECHNOLOGY AND WET INJECTION	9.0	BACT-PSD
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945	SCR	9.0	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE, LA	3/2/1995	?	TURBINE/HRSG, GAS COGENERATION	450	DLN BURNER/COMBUSTION DESIGN AND CONTROL	9.0	LAER
FORMOSA PLASTICS CORP, BATON ROUGE PLANT	BATON ROUGE, LA	3/7/1997	YES	TURBINE/HSRG, GAS COGENERATION	450	DLN BURNER/COMBUSTION DESIGN AND CONSTRUCTION	9.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	?	(2) GAS TURBINES	1,908	DLN COMBUSTORS AND BURNERS	9.0	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	?	(2) COGENERATION UNITS COMBINED CYCLE	320	SCR	9.0	BACT-PSD
CARVILLE ENERGY CENTER	NORTHBROOK, IL	5/16/2001	?	(2) GAS TURBINES (1-98A, 2-98A)	1,908	DLN COMBUSTOR AND BURNERS	9.0	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	9.0	OTHER
CHAMPION INTL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	DLN BURNER	9.0	BACT-OTHER
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINTS AA-001, 002, 003	2,248	SCR	9.0	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINES COMB CYCLE W/ & W/O DB	2,400	SCR AND DLN BURNERS	9.0	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	DLN COMBUSTORS	9.0	BACT-PSD
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	DLN COMBUSTOR	9.0	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNERS	9.0	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNER WITH NATURAL GAS	9.0	BACT-PSD
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	SCR ON TURBINES & DBS AND DRY LNB'S ON TURBINES	9.0	BACT-PSD
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	SCR	9.0	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	LOW NOX COMBUSTORS, SCR	9.0	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	SCR	9.0	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	NONE INDICATED	9.0	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	SCR	9.0	NSPS
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINES GT-HRSG 1-4 W/ AND W/O DB	2,000	DLN BURNERS	9.0	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	SCR	9.0	NSPS
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	DLN COMBUSTORS	9.0	BACT-PSD
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	9.0	BACT-OTHER
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	9.0	NSPS
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	DLN COMBUSTION DESIGN	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE DUCT BURNER	1,488		9.4	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	DLN BURNERS	9.0	BACT-PSD
				(3) COMBUSTION TURBINES WITHOUT DB, W/ STEAM INJECTION	1,440		12.0	
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		13.4	
BASTROP CLEAN ENERGY CENTER		3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	LNB, FIRING ONLY NAT GAS	9.0	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		12.6	
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	DLN COMBUSTORS	9.0	BACT-PSD
				(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		13.0	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	DLN BURNERS	9.0	BACT-PSD
				(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		13.0	
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	DLN COMBUSTORS	9.0	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		13.4	
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	DLN BURNERS	9.0	BACT-PSD
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		14.0	
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE	1,698	DLN COMBUSTORS	9.0	BACT-PSD
				(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698		15.0	
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/O DUCT FIRING	1,698	DLN COMBUSTION	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698		15.0	
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	SCR, WATER INJECTION	9.0	BACT-PSD
				COMBUSTION TURBINE, W/O DUCT BURNER	908		24.5	
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	DLN COMBUSTION (DLN MODE)	9.0	BACT-PSD
				(6) TURBINE GE LM 6000 COMBINED CYCLE	416		25.0	

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Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	(2) GAS TURBINES UNITS 1 & 2 W/O DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	11.2	BACT-OTHER
				(2) GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602		21.7	
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) COMBINED CYCLE GENERATION UNIT	1,464	LNB, SCR	11.6	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC.	PRYOR, OK	3/24/1999		ELECTRIC GENERATION, TURBINE, NATURAL GAS	4,240	DRY LOW NOX COMBUSTOR	12.0	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	DLN COMBUSTORS	12.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	DLN BURNERS VERSION 2.6 BY GE	12.0	BACT-OTHER
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	DLN BURNERS WITH SCR	12.0	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	DLN BURNERS	12.0	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1, 2, 3	3,168	DLN BURNERS	12.2	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	SCR	12.5	BACT-PSD
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	DLN BURNERS USE OF STEAM INJECTION AS NECESSARY	12.8	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	12/14/1992		TURBINE,GAS	1,214	DRY LOW NOX COMBUSTOR	15.0	BACT-PSD
TIGER BAY LP	FL	5/17/1993		TURBINE, GAS	1,615	DRY LOW NOX COMBUSTOR	15.0	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION (ABB OR GE)	600	DLN BURNER	15.0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB STAGED COMBUSTION	15.0	BACT-PSD
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	?	(2) TURBINES, COMBINED CYCLE	1,280	DLN COMBUSTOR	15.0	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	LNB	15.0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	SCR WITH LOW NOX COMBUSTORS	15.0	BACT-OTHER
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	15.0	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/ AND W/O DUCT BURNER FIRING	672	DLN BURNERS	15.0	BACT-OTHER
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	LOW NOX COMBUSTORS, WATER INJECTION & SCR	15.0	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	LNB	15.0	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		15.8	
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	DLN COMBUSTORS FOR TURBINE AND DUCT BURNER	15.0	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464		16.7	
GREGORY POWER FACILITY	TEXAS	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	DLN BURNERS	15.0	BACT-PSD
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		16.8	
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE	457	LNB	15.0	BACT-PSD
				COMBUSTION TURBINE W/ DUCT BURNER	623		19.0	
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	DLN BURNERS	15.0	BACT-OTHER
				(4) GAS TURBINE/HRSG 1-4, EPN1-4, W/ DUCT BURNER	970		25.0	
COLORADO SPRINGS UTILITIES	FOUNTAIN, CO	4/19/1999	YES	TURBINE, COMBINED (70%-100% LOAD)	264	DLN COMBUSTION, < 70% LOAD OPERATION IS MINIMIZED	15.0	BACT-PSD
				TURBINE, COMBINED (<70% LOAD)	264		65.0	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	CASE I: TURBINE E-1 W/O HRSG	720	NONE INDICATED	15.0	NSPS
				CASE I: TURBINE E-2 W/O HRSG	720		15.0	
				CASE II: TURBINE E-1 W/ HRSG	720		85.4	
				CASE II: TURBINE E-2 W/ HRSG	720		74.5	
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	SCR	15.3	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY, DE	3/30/1998	YES	(2) TURBINES, COMBINED CYCLE	827	NITROGEN INJECTION WHILE FIRING GAS	16.0	LAER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	DLN COMBUSTION FOR TURBINES AND DUCT BURNERS	17.0	BACT-PSD
MANSFIELD MILL	MANSFIELD, LA	8/14/2001	?	GAS TURBINE/HRSG	654	DLN BURNER	21.7	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	SCR	23.0	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	?	COMBINED CYCLE TURBINE (25 MW)	568	DLN COMBUSTOR DESIGN	25.0	BACT-PSD
WRIGHTSVILLE POWER FACILITY	WRIGHTSVILLE, AR	2/28/2000	?	(6)TURBINE, COMBUSTION GE LM6000	368	STEAM INJECTION	25.0	BACT-PSD
KENTUCKY PIONEER ENERGY, LLC - TRAPP	KENTUCKY	6/7/2001	?	(2) TURBINES, COMBINED CYCLE	1,765	STEAM INJECTION	25.0	BACT-PSD
INTERNATIONAL PAPER	MANSFIELD, LA	2/24/1994	?	TURBINE/HRSG, GAS COGEN	338	DLN COMBUSTOR/COMBUSTION CONTROL	25.0	BACT-OTHER
PINE STATE POWER"	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	WI "QUIET COMBUSTOR" MULTI FUEL NOZZLE CAP ; LNB DB	25.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	TURBINE, COMBINED CYCLE	984	LNB	25.0	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	DILUTION PRIOR TO COMB & DILUTION INJ. IN COMB ZONE	25.0	BACT-PSD
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	SCR	25.0	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	WATER/STEAM INJECTION, COMBUSTION MODIFICATION	25.0	BACT-PSD
SWEENY COGENERATION LIMITED PARTNERS	DALLAS, TX	9/9/1996	?	(3) COMBINED CYCLE TURBINES	970	DLN BURNERS	25.0	BACT-OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	DLN BURNERS	25.0	RACT
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	LOW NOX COMBUSTORS	25.0	BACT-OTHER
LORDSBURG L.P.	LORDSBURG, NM	6/18/1997		TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	800	SCHEDULED COMBUSTION.	25.2	BACT-PSD
SUNLAW COGEN. (FEDERAL COLD STORAGE COGEN)	VERNON, CA	1/15/1994	?	TURBINE, COMBINED CYCLE AND COGEN	224	WI AND SCONOX (MOD 2) CATALYST SYSTEM AFTERHRSG	25.8	BACT-OTHER
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	STACK EMISSIONS (TURBINE & DUCT BURNER)	610	WATER INJECTION	36.0	BACT-OTHER
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848	LNB W/ STEAM INJECTION	42.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(11) TURBINE, COMBINED CYCLE	984	EXISTING STEAM INJECTION	42.0	BACT-PSD
LEDERLE LABORATORIES	PEARL RIVER, NY	9/15/1994	?	(2) GAS TURBINES (EP #S 00101&102)	110	STEAM INJECTION	42.0	BACT-PSD
BORDEN CHEMICALS AND PLASTICS	GEISMAR, LA	5/29/2001	?	COGEN II	471	STEAM INJECTION	51.0	BACT-PSD
BORDEN CHEMICALS AND PLASTICS OPERATING, LP	GEISMAR, LA	5/29/2001	?	COGEN III UNIT	473	STEAM INJECTION	62.0	RACT
HOFFMAN-LA ROCHE, NUTLEY COGEN FACILITY	NUTLEY, NJ	5/8/1995	YES	TURBINE, GM LM500	87	NONE INDICATED	92.1	RACT
GULF STATES UTILITIES COMPANY - LOUISIANA STA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	NONE INDICATED	100.0	OTHER
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	CEM, DLN COMBUSTORS AND GCP	102.0	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, CEMS, CONTINUOUS EMISSION MONITOR, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-2
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SIEMENS SGT6-5000F COMBUSTION TURBINES W/ DB	2205	CO CATALYST	0.9	BACT-PSD
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 2	1944	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST.	1.2	BACT-PSD
				ELECTRIC GENERATION - SCENARIO 1	1717	GOOD COMBUSTION PRACTICES.OXIDATION CATALYST.	1.3	BACT-PSD
				ELECTRIC GENERATION - SCENARIO 3	2204	CEM SYSTEM. GCP AND OXIDATION CATALYST.	1.8	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	OXIDATION CATALYST AND GCP	1.3	BACT
				(2) COMBINED CYCLE TURBINES W/ POWER AUGMENTATION, GE 7FA	1,717		1.8	
				(2) COMBINED CYCLE TURBINES W/ DUCT BURNER, GE 7FA	2,217		2.5	
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	1.5	LAER
BP CHERRY POINT COGENERATION PROJECT	WHATCOM CO., WA	1/11/2005	?	GE 7FA COMBUSTION TURBINE	1,392	LEAN PRE-MIX CT BURNER & OXIDATION CATALYST	2.0	BACT-PSD
WANAPA ENERGY CENTER	UMATILLA, OR	8/8/2005	?	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	2384.1	OXIDATION CATALYST.	2.0	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	OXIDATION CATALYST	2.0	BACT
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	OXIDATION CATALYST	2.0	BACT
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) COMBINED CYCLE TURBINES	2,160	OXIDATION CATALYST AND EFFICIENT COMBUSTION	2.0	BACT
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	CATALYTIC REDUCTION	2.0	OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	2.0	BACT
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	OXIDATION CATALYST	2.0	BACT
AUGUSTA ENERGY CENTER	AUGUSTA, GA	10/28/2001	?	(3) TURBINE, COMBINED CYCLE	2,000	CATALYTIC OXIDATION	2.0	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	CATALYTIC OXIDATION	2.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	GCP	2.0	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	OXIDATION CATALYST AND GCP	2.0	BACT-PSD
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	OXIDATION CATALYST	2.0	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	OXIDATION CATALYST	2.0	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE W/ AND W/O DB	2,964	CO CATALYST	2.0	OTHER
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	CATALYTIC OXIDATION	2.0	BACT-PSD
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	?	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	CATALYTIC OXIDATION	2.0	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	OXIDATION CATALYST	2.0	BACT-OTHER
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	OXIDATION CATALYST	2.0	BACT-OTHER
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	OXIDATION CATALYST	2.0	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	OXIDATION CATALYST	2.0	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	CO CATALYST AND EFFICIENT COMBUSTION TECHNIQUES	2.0	BACT
				(3) COMBINED CYCLE TURBINES	2,049		2.8	
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	(2) TURBINE, COMBINED CYCLE	1,360	CATALYTIC OXIDIZER	3.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955	OXIDATION CATALYST	2.0	OTHER
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779		3.9	
				(1) COMBINED CYCLE COMBUSTION TURBINE, W/ DUCT BURNER	2,423	OXIDATION CATALYST	2.0	LAER
CON ED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054		4.0	
				(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165	GCP AND OXIDATION CATALYST	2.0	BACT-PSD
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440		10.0	
				(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440	DLN COMBUSTION TECHNOLOGY	2.0	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	OXIDATION CATALYST	2.3	NSPS
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181		2.4	
				(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		2.5	
				(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		3.1	
DICKERSON	MONTGOMERY, MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	1,568	OXIDATION CATALYST	2.4	N/A
				(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181	OXIDATION CATALYST	2.5	LAER
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	2.5	BACT-PSD
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	GCP	2.5	BACT-OTHER
CONECTIV BETHLEHEM, INC.	PENNSYLVANIA	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	OXIDATION CATALYST	2.5	BACT
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742		4.0	
				(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742	OXIDATION CATALYST	2.5	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742		4.0	
				(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742	OXIDATION CATALYST	2.8	BACT-PSD
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	OXIDATION CATALYST	2.6	LAER
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900		3.5	
				(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DB	1,900	OXIDATION CATALYST	3.0	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, ABB GT-24 #1 &#2 WITH 2 CHILLERS (100% LOAD)	1,965		11.8	
				(2) TURBINE, ABB GT-24 #1&#2 WITH 2 CHILLERS (50-99% LOAD)	1,965	OXIDATION CATALYST	3.0	BACT
HERITAGE STATION	SCRIBA NY	10/12/2000	NO			CO CATALYST	3.0	BACT-PSD
S.W.E.C, LLC	FALLS TWP, PA	2001	NO			OXIDATION CATALYST	3.0	BACT-PSD
SARANAC ENERGY COMPANY	PLATTSBURGH, NY	7/31/1992	YES	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123	OXIDATION CATALYST	3.0	BACT-OTHER
ROCKY MOUNTAIN ENERGY CENTER, LLC	WELD, CO	5/2/2006	?	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	2,400	USE GCP AND CATALYTIC OXIDATION.	3.0	BACT-PSD
WELLTON MOHAWK GENERATING STATION	YUMA, AZ	12/1/2004	?	COMBUSTION TURBINE GENERATORS - GE7FA TURBINES OPTION	1,360	OXIDATION CATALYST	3.0	BACT-PSD
WELLTON MOHAWK GENERATING STATION	YUMA, AZ	12/2/2004	?	COMBUSTION TURBINE GENERATORS - GE7FA TURBINES OPTION	1,360	OXIDATION CATALYST	3.0	BACT-PSD
COPPER MOUNTAIN POWER	CLARK CO., NV	5/14/2004	?	LARGE COMBUSTION TURBINES COMBINED CYCLE & COGENERATION	4,800	GOOD COMBUSTOR DESIGN AND AN OXIDATION CATALYST	3.0	LAER
VINEYARD ENERGY CENTER, LLC	VINEYARD, UT	5/11/2004	NO	(3) SWPC 501F COMBUSTION TURBINES	1,738	OXIDATION CATALYST	3.0	BACT-OTHER
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	CATALYTIC OXIDIZER	3.0	LAER
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	CATALYTIC OXIDIZER	3.0	LAER
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	OXIDATION CATALYST	3.0	BACT-PSD
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	OXIDATION CATALYST	3.0	LAER
FAIRLESS WORKS ENERGY CTR (FMR SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	3.0	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	CATALYTIC OXIDIZER	3.0	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	THE USE OF OXIDATION CATALYST SYSTEM	3.0	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE (50%-100% LOAD)	2,010	OXIDATION CATALYST	3.0	BACT
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (100% LOAD)	2,181		4.0	
				(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (75% LOAD)	2,181		20.0	
				(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (50% LOAD)	2,181	OXIDATION CATALYST	3.0	BACT-PSD
ANP BELLINGHAN ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, ABB GT-24 (75%-100%) W/ STEAM INJECTION	1,815		4.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (50%-75%)	1,361		20.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (<50%)	908	OXIDATION CATALYST	3.0	BACT-PSD
ANP BLACKSTONE ENERGY COMPANY	MARLBOROUGH, MA	4/16/1999	?	(2) TURBINES, ABB GT-24 (75%-100%) W/ STEAM INJECTION	1,815		4.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (50%-75%)	1,361		20.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (<50%)	908	OXIDATION CATALYST	3.0	OTHER
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, W/ STEAM INJECTION	1,897		4.0	
				(4) COMBINED CYCLE TURBINES, 75%-100%	1,897		20.0	
				(4) COMBINED CYCLE TURBINES, 50%-74%	1,404	GCP AND OXIDATION CATALYST	3.0	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360		5.0	
				(3) TURBINES, STATIONARY GAS COMBINED CYCLE, W/ POWER AUG.	1,360	OXIDATION CATALYST	3.1	OTHER
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224		22.1	
				COMBUSTION TURBINE W/ HEAT RECOVERY BOILER (75% LOAD)	1,224	GCP	3.1	BACT-PSD
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE (70%-100%)	2,132		16.0	
				(2) TURBINE, COMBINED CYCLE (<70%)	1,492	GOOD COMBUSTION AND OXIDATION CATALYST	3.5	BACT-PSD

Appendix E: Table E-2
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE (75%-100%)	1,440		10.0	
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/16/2005	?	TURBINE, COMBINED CYCLE COMBUSTION #1 W/DB	2,448	OXIDATION CATALYST	3.5	BACT-PSD
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/16/2005	?	TURBINE, COMBINED CYCLE COMBUSTION #2 W/ DB	2,448	OXIDATION CATALYST SYSTEM	3.5	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	CATALYTIC OXIDATION SYSTEM	3.6	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE	2,200		3.8	
				(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200	OXIDATION CATALYST	3.9	LAER
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	?	GAS TURBINES - 187 MW (2)	2006	CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	3.9	BACT-PSD
BROOKLYN NAVY YARD COGEN PARTNERS L.P.	NEW YORK CITY, NY	6/6/1995	YES	TURBINE, NATURAL GAS FIRED		CO CATALYST	4.0	LAER
ARSENAL HILL POWER PLANT	CADDO,LA	3/20/2008		TWO COMBINED CYCLE GAS TURBINES	2,110	GOOD COMBUSTION CONTROL	4.0	LAER
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	CATALYTIC OXIDATION AND USE OF GCP	4.0	BACT-PSD
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES	1,611	OXIDATION CATALYST	4.0	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	?	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883		#REF!	
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	GCP	4.1	BACT-OTHER
FP&L TURKEY POINT FOSSIL PLANT - UNIT 5	HOMESTEAD, FL	6/1/2004	NO	(4) COMBUSTION TURBINE	1,608	NONE INDICATED	14.0	
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	?	2-COMBUSTION TURBINES W/ DUCT BURNER	2,000	EMISSION LIMITS, NOT CONTROLS WERE SPECIFIED	4.1	BACT-PSD
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	?	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	OXIDATION CATALYST	5.0	BACT
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	NONE INDICATED	5.0	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	NONE INDICATED	5.0	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	OXIDATION CATALYST	5.0	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	CATALYTIC OXIDATION	5.0	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	OXIDATION CATALYST	5.0	BACT-PSD
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	GCP CO CATALYST OXIDATION CATALYST	5.0	BACT-PSD
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	?	(2) TURBINE, COMBINED CYCLE	2,240	GCP	5.0	BACT-PSD
CHAMBERS ENERGY L.P./ANP	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	NONE INDICATED	5.0	BACT-PSD
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE W/ AND W/O POWER AUGMENTATION	2,000		7.5	
INDECK-NILES, LLC	NILES, MI	12/2/2001	?	(4) GAS TURBINES COMBINED CYCLE	2,152	CATALYTIC OXIDATION	5.0	BACT-PSD
				(4) GAS TURBINES COMBINED CYCLE W/ DUCT BURNER	2,152		10.0	
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650		20.0	
				(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	GCP	5.0	BACT-PSD
				(3) TURBINE, COMBINED CYCLE AND DUCT BURNER, POWER AUG.	2,300		25.0	
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(6) GAS FUELED TURBINES, 1-6	2,133	OXIDATION CATALYST SYSTEM	5.0	BACT-PSD
				(6) GAS FUELED TURBINES, 1-6 W/STEAM INJ. OR EVAP COOLING	2,133		25.0	
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440	CATALYTIC OXIDATION	5.2	BACT-OTHER
				(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440	NONE INDICATED	5.3	OTHER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	CATALYTIC OXIDATION	5.4	BACT-OTHER
CONTINENTAL ENERGY SVCS, SILVER BOW GEN	BUTTE, MT	6/7/2002	NO	(4) COMBINED CYCLE CT	1,400	NONE INDICATED	5.6	BACT-OTHER
CROCKETT COGENERATION - C&H SUGAR	CROCKETT, CA	10/5/1993	YES	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	1920	OXIDATION CATALYST	5.9	BACT-OTHER
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	YES	(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400	OXIDATION CATALYST	6.0	LAER
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	OXIDATION CATALYST	6.0	LAER
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	YES	(2) TURBINE, COMBINED CYCLE, DUCT BURNER CC4, CC5	2,640	OXIDATION CATALYST	6.0	LAER
MOUNTAINVIEW POWER	SAN BERNARDINO, CA	5/22/2001	YES	(4) TURBINE, COMBINED CYCLE	1,991	GOOD COMBUSTION	6.0	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	GCP	6.0	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	OXIDATION CATALYST	6.0	LAER
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	OXIDATION CATALYST	6.0	BACT-PSD
LOWER MOUNT BETHEL ENERGY, LLC	FAIRFAX	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	GOOD COMBUSTION	6.0	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984		9.0	
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360	GCP	6.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945		9.0	
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE	1,944	NONE INDICATED	6.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944		9.0	
DUKE ENERGY HANGING ROCK ENERGY	OHIO	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376	NONE INDICATED	6.0	BACT-PSD
				(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376		13.5	
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	DLN/GOOD COMBUSTION	7.0	BACT-PSD
				(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374	GOOD COMBUSTION DESIGN AND PRACTICES	7.4	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	GOOD COMBUSTION DESIGN AND PRACTICES	7.4	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE	1,600	NONE INDICATED	7.4	BACT-PSD
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYCLE	1,600		14.5	
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, NO DUCT BURNER FIRING	1,937	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	7.8	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	1,937	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	7.8	BACT-PSD
TECO BAYSIDE POWER STATION	TAMPA, FL	3/30/2001	YES	(7) TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION	7.8	BACT-PSD
TECO BAYSIDE POWER STATION	TAMPA, FL	1/8/2002	?	(11) TURBINE, COMBINED CYCLE	1,360	GCP	7.8	BACT-PSD
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360		13.4	
HINES POWER BLOCK 4	POLK, FL	6/8/2005	?	COMBINED CYCLE TURBINE	4,240	GOOD COMBUSTION	8.0	BACT-PSD
HINES POWER BLOCK 4	POLK, FL	6/8/2005	?	COMBINED CYCLE TURBINE	4,240	GOOD COMBUSTION	8.0	BACT-PSD
FPL TURKEY POINT POWER PLANT	DADE,FL	2/8/2005	?	170 MW COMBUSTION TURBINE, 4 UNITS	1,360	EFFICIENT COMBUSTION OF NATURAL GAS	8.0	BACT-PSD
FPL ENERGY MARCUS HOOK, L.P.	JUNO BEACH, FL	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	COMBUSTION CONTROLS	8.0	BACT-PSD
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191	COMBUSTION CONTROLS	8.0	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,680	CATALYTIC AFTERBURNER	8.0	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,680	OXIDATION CATALYST	8.0	BACT
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440		12.0	
El Paso Broward Energy Center	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	GCP	8.0	BACT-PSD
				(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742		13.8	
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?	(2) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,737	OXIDATION CATALYST	8.1	BACT-PSD
				(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	GCP	8.2	BACT-PSD
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	NO	(3) TURBINE, COMBINED CYCLE	1,467	COMBUSTION CONTROL	8.2	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	?	(2) TURBINE, COMBINED CYCLE (GE)	1,360		11.4	
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	GE COMBUSTION TURBINE & DUCT BURNERS	1,705	STATE OF THE ART COMBUSTER DESIGN AND GOOD OPERATING PRACTICES	8.2	BACT-PSD
				GE COMBUSTION TURBINE W/O DUCT BURNERS	1,705		13.8	
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	NONE INDICATED	8.2	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400	CLEAN FUEL, GOOD COMBUSTION AND DESIGN	8.5	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	YES	TURBINE, COMBUSTION GAS (150 MW)	1146	COMBUSTION CONTROL	8.5	BACT-OTHER
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	NO	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000	GCP AND OXIDATION CATALYST (CONTROL)	9.0	BACT-PSD
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT FIRING (70%-100%)	2,200	COMBUSTION CONTROLS	9.0	BACT-PSD
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	YES	(2) COMBINED-CYCLE TURBINE	2,311	GCP	9.0	BACT-PSD
CPV GULFCOAST POWER GENERATING	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	GOOD COMBUSTION	9.0	BACT-PSD
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	NONE INDICATED	9.0	BACT-OTHER
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	COMBUSTION CONTROL	9.0	BACT-PSD
CHAMPION INTERNATL CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	COMBUSTION CONTROL	9.0	BACT-PSD
CAROLINA POWER AND LIGHT - RICHMOND CO	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	COMBUSTION CONTROL	9.0	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	GOOD COMBUSTION	9.0	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	COMBUSTION TECHNOLOGY/CLEAN FUELS	9.0	BACT-PSD

Appendix E: Table E-2
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	LNB, GCP	9.0	BACT-PSD
SANTEE COOPER RAINEY GEN STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	GCP	9.0	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES TURBINE W/ AND W/O DUCT BURNER	1,384	GCP & OXIDATION CATALYST SYSTEM	9.0	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINE W/ AND W/O DUCT BURNERS GT-HRSG 1-4	2,000	GCP	9.0	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840		12.0	
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE	1,973	GCP	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		13.7	
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	GCP, NATURAL GAS AS FUEL	9.0	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		14.0	
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	GCP AND DESIGN	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791		14.0	
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	GCP	9.0	BACT-PSD
				(2) TURBINES, COMBINED CYCLE DUCT BURNERS	1,985		14.6	
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE	1,827	COMB DESIGN & GOOD OPER PRACTICE. DLN COMBUSTION	9.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		15.0	
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	NONE INDICATED	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE DUCT BURNER	1,488		15.0	
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	GCP	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		15.0	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440		16.3	
				(3) COMBUSTION TURBINES W/O DB CTG (1), (2), (3) W/ STEAM INJ.	1,440	GCP	9.0	BACT-PSD
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		15.4	
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,698	DLN COMBUSTORS, GCP	9.0	BACT-PSD
				(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698		15.4	
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/O DUCT FIRING	1,698	GCP	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698		16.4	
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION	1,735	COMBUSTION CONTROLS	9.0	BACT-PSD
				(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735		20.0	
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	GCP	9.0	BACT-PSD
				COMBINED CYCLE COMBUSTION TURBINE, W/ POWER AUG.	1,700		20.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE GE	1,400	LNB	9.0	BACT-PSD
				(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		25.0	
CPV GULFCOAST LTD	MANATEE CO, FL	2/6/2001	NO			COMBUSTION CONTROLS	9.0	BACT-PSD
DICKERSON	MONTGOMERY, MD	11/5/2004	?	UNIT 5 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	1,568	OXIDATION CATALYST	9.2	N/A
BRIDGEPORT ENERGY, LLC	BRIDGEPORT, CT	6/29/1998	YES	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	2,080	PRE-MIX FUEL FAIR TO OPMITIZE EFFICIENCY ACTUAL EMISSIONS EXPECTED BETWEEN 5-7PPM	10.0	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC.	PRYOR, OK	3/24/1999		ELECTRIC GENERATION, TURBINE, NATURAL GAS	4,240	COMBUSTION CONTROLS	10.0	BACT-PSD
NORTHERN STATES POWER DBA XCEL ENERGY - RIVERSIDE	RAMSEY, MN	5/16/2006	?	TURBINE, COMBINED CYCLE (2)	1885	GOOD COMBUSTION PRACTICES	10.0	BACT-PSD
HIGH BRIDGE GENERATING PLANT	RAMSEY, MN	8/12/2005	?	2 COMBINED-CYCLE COMBUSTION TURBINES	2,640	GOOD COMBUSTION PRACTICES	10.0	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP	10.0	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288	GCP, DLN COMBUSTORS	10.0	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,876	OXIDATION CATALYST	10.0	BACT-OTHER
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	YES	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	OXIDATION CATALYST	10.0	BACT-OTHER
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	COMBUSTION DESIGN GCP	10.0	BACT-PSD
BEAR MOUNTAIN LIMITED"	BAKERSFIELD, CA	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	GOOD COMBUSTOR DESIGN, ONLY "SWEET" NATURAL GAS	10.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION CONTROLS	10.0	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	COMBUSTION CONTROL	10.0	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	NONE INDICATED	10.0	BACT-OTHER
DUKE ENERGY STEPHENS, LLC STEPHENS	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	CATALYTIC CONTROL	10.0	LAER
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	NONE INDICATED	10.0	BACT-PSD
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	PROPER COMBUSTION CONTROL	10.0	BACT-PSD
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	PROPER COMBUSTION	10.0	BACT-PSD
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4, W/ AND W/O DUCT BURNER	970	TURBINES OPERATE BASE LOAD AT LEAST 75% OF TIME	10.0	BACT-PSD
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000		13.9	
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	NONE INDICATED	10.0	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		14.0	
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	GCP	10.0	BACT-PSD
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		15.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE MHI/SW	1,400		20.6	
				(4) TURBINES, COMBINED CYCLE MHI/SW @ 75% LOAD	1,400	OXIDATION CATALYST	10.0	BACT-OTHER
				(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		25.0	
KANSAS CITY POWER & LIGHT CO HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED (70%-100% LOAD)	1,360	GCP/CO OXIDATION CATALYST	10.2	BACT-PSD
				(2) TURBINE, COMBINED (>70% LOAD)	1,360	CATALYTIC OXIDATION	10.2	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	LNB	10.3	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	GCP	10.3	BACT-PSD
SWEENY COGENERATION LIMITED PARTNERS	DALLAS, TX	9/9/1996	?	(3) COMBINED CYCLE TURBINES	970	NONE INDICATED	11.0	BACT-PSD
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962		17.0	
FAIRBAULT ENERGY PARK	RICE, MN	6/5/2007		COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	1758	GOOD COMBUSTION	11	BACT-PSD
DOSWELL LIMITED PARTNERSHIP	VA	5/4/1990	YES	TURBINE, COMBUSTION	1261	COMBUSTION DESIGN AND OPERATION	11.0	OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE, RI	4/13/1992	YES	TURBINE, GAS AND DUCT BURNER	1360	COMPLETE COMBUSTION	11.0	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	GOOD OPERATING PRACTICE	11.5	BACT-PSD
				(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400	GCP AND EFFICIENT PROCESS DESIGN	11.6	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372		25.9	
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TWP, NJ	4/1/1991	YES	TURBINES (NATURAL GAS) (2)	1190	TURBINE DESIGN	11.6	BACT-OTHER
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE	1,844	CATALYTIC OXIDIZER	12.0	BACT-PSD
				(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844	GOOD COMBUSTION	12.0	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON, RI	2/13/1998				GOOD COMBUSTION	12.0	BACT-PSD
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	FL	10/15/1999	NO	TURBINE-GAS, COMBINED CYCLE	4,000	COMBUSTION COMBUSTION	12.0	BACT-PSD
HOT SPRINGS POWER PROJECT	ARKANSAS	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	GOOD COMBUSTION	12.0	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	GCP	12.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	GOOD COMBUSTION TECHNIQUES	12.0	BACT-PSD
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	NONE INDICATED	12.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(12) TURBINE, COMBINED CYCLE	984	COMBUSTION CONTROLS	12.0	BACT-PSD
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	?	(2) TURBINES, COMBINED CYCLE	1,280	GCP	12.0	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795		20.0	
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE	1,696	NONE INDICATED	12.2	BACT-PSD
				TURBINE, COMBINED CYCLE & DUCT BURNER	1,696	GOOD COMBUSTION	12.2	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	GCP	12.9	OTHER
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	GCP	13.0	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000		18.4	
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO, NY	11/24/1992	YES	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133	COMBUSTION CONTROLS	13.0	BACT-OTHER

Appendix E: Table E-2
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	GCP	13.2	BACT-PSD
				(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		20.2	
TENASKA FRONTIER GENERATION STATION	TEXAS	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	NONE INDICATED	13.3	OTHER
				(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464	DLN COMBUSTORS	13.3	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	EFFICIENT COMBUSTION	13.4	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	EFFICIENT COMBUSTION	13.4	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	GCP	13.4	BACT-PSD
TIGER BAY LP	FL	5/17/1993		TURBINE, GAS	1614.8	GOOD COMBUSTION PRACTICES	13.5	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	GOOD COMBUSTION	14.0	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	OXIDATION CATALYST	14.0	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE NO DUCT BURNER	1,400	NONE INDICATED	14.0	LAER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP	14.4	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	EFFICIENT COMBUSTION	15.0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	BOARDMAN, OR	5/31/1994	YES	TURBINES, NATURAL GAS (2)	1720	GOOD COMBUSTION PRACTICES	15.0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	12/14/1992		TURBINE,GAS	1214	GOOD COMBUSTION PRACTICES	15.0	BACT-PSD
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	EFFICIENT COMBUSTION	15.0	BACT-PSD
DUKE ENERGY DALE, LLC	ALABAMA	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	EFFICIENT COMBUSTION	15.0	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	ALABAMA	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	GE DLN COMBUSTOR DESIGN, GOOD COMBUSTION CONTROL	15.0	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	USING 15 % EXCESS AIR	15.0	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD, ME	5/1/1998	YES	TURBINE GENERATOR COMBUSTION	1,906	NONE INDICATED	15.0	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	LNB WITH GCP	15.0	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE	2,096	LNB WITH GCP	15.0	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	GOOD COMBUSTION	15.0	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	NONE INDICATED	15.0	BACT-PSD
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	NONE INDICATED	15.0	NSPS
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	(2) COMBUSTION TURBINES #1 & #2	1,836	PROPER COMBUSTION CONTROL	15.0	BACT-OTHER
HERMISTON POWER PARTNERSHIP	OREGON	4/13/1999	?	(2) TURBINE	1,853	GCP	15.0	OTHER
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	OXIDATION CATALYST	15.0	BACT-PSD
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP	15.0	BACT-PSD
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360		16.0	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	LNB	15.0	BACT-PSD
				(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		20.0	
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE	457	GCP WITH NATURAL GAS AS FUEL	15.0	BACT-PSD
				COMBUSTION TURBINE W/ DUCT BURNER	623		24.8	
GEISMAR PLANT	GEISMAR, LA	2/26/2002	?	(2) COGENERATION UNITS POINT # 720-99 AND 721-99, W/O DB	320	CLEAN BURNING FUELS & EFFICIENT COMBUSTION TECHNIQUES	15.0	BACT
				(2) COGENERATION UNITS POINT # 720-99 AND 721-99, W/ DB	320		30.0	
LORDSBURG L.P.	LORDSBURG, NM	6/18/1997		TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	800	COMBUSTION EFFICIENCY	15.1	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	GCP	15.3	BACT-PSD
				(3) SWPC 510G COMBUSTION TURBINES (75% LOAD)	2,880		24.0	
SALT RIVER PROJECT/ DESERT BASIN GEN	PHOENIX, AZ	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	NONE INDICATED	15.2	OTHER
				TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		31.7	
LANSING SMITH	SOUTHPORT, FL	7/31/200	?	COMBUSTION TURBINES - GAS FIRED		NO	16.0	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	TURBINES E-1+E-2 W/O HRSG	720	COMBUSTION DESIGN, GCP	16.0	BACT-PSD
LAWTON ENERGY COGEN FACILITY	COMANCHE, OK	12/12/2006	?	COMBUSTION TURBINE AND DUCT BURNER		GOOD COMBUSTION PRACTICES	16.4	BACT-PSD
				TURBINES E-1+E-2 W/ HRSG	720	NONE INDICATED	16.6	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	GOOD COMBUSTION	17.0	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	GOOD COMBUSTION CONTROLS	17.0	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	GCP/DESIGN	17.2	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	NONE INDICATED	17.4	BACT-OTHER
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	NONE INDICATED	17.4	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	GCP AND CLEAN BURNING FUEL, DLN	17.4	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	GCP	17.8	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP	17.8	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	EFFICIENT COMBUSTION	17.8	BACT-PSD
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	GOOD COMBUSTION CONTROL	18.0	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	COMBUSTOR DESIGN AND OPERATION	18.0	BACT-PSD
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320		25.0	
XCEL ENERGY, BLACK DOG ELECTRIC GEN	BURNSVILLE, MN	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	GCP	18.3	BACT-PSD
				COMBUSTION TURBINE WITH HRSG W/ DUCT BURNER	2,427	GOOD COMBUSTION & CATALYTIC OXIDATION	18.4	BACT-OTHER
RELIANT ENERGY CHOCTAW COUNTY, LLC	CHOCTAW, MS	11/23/2004	?	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE	1,840	SCR	18.4	BACT-PSD
SOUTHERN ENERGY, INC.	ZEELAND, MI	3/16/2000	NO	COMBINED CYCLE TURBINE ELECTRICAL GENERATING UNITS		CEM GOOD COMBUSTION PRACTIVE REQUIRED. RATE PER TURBINE (CT).	18.7	BACT-PSD
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GOOD DESIGN,PROPER OPERATION & MAINTENANCE	19.0	BACT-PSD
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	NO	(2) TURBINE, COMBINED CYCLE	640	GCP	19.7	BACT-PSD
PPG INDUSTRIES	LAKE CHARLES, LA	12/2/1999	?	COGENERATION UNIT 5 AND 6 (EACH)	1,320		68.2	
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480	NONE INDICATED	20.0	BACT-PSD
				TURBINE, COMBINED CYCLE (<75% LOAD)	1,480	DLNB, GCP	20.0	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	YES	TURBINE, COMBINED CYCLE	2,040	GCP	20.0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	15% EXCESS AIR	20.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	GOOD COMBUSTION CONTROL	20.0	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE, ME	7/13/1998	NO	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO		15% EXCESS AIR	20.0	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	LOW NOX COMBUSTOR, GCP	20.0	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	OXIDATION CATALYST	20.0	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	NONE INDICATED	20.0	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	GCP	20.0	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	GCP	20.0	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	NONE INDICATED	20.0	BACT-OTHER
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	GOOD COMBUSTION	20.0	BACT-PSD
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800		26.2	
GREGORY POWER FACILITY	TEXAS	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	EFFICIENT COMBUSTION	20.1	BACT-PSD
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480	GOOD COMBUSTION	20.2	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	BEST COMBUSTION CONTROL PRACTICES	21.0	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1, 2, 3	888	NONE INDICATED	22.1	OTHER
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	GCP	22.3	BACT-PSD
GULF STATES UTILITIES COMPANY - LOUISIANA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	GOOD COMBUSTION	23.0	BACT-PSD
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	NONE INDICATED	23.0	OTHER
PINNACLE WEST ENERGY CORP./REDHAWK GEN	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	INTERNAL COMBUSTION CONTROLS	23.0	BACT-OTHER
RELIANT ENERGY- CHANNELVIEW COGENERATION	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350		35.7	
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	(2) GAS TURBINES UNITS 1 & 2 W/O DUCT BURNER	602	GCP	23.2	BACT-PSD
				(2) GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	GCP	23.2	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	GOOD OPERATING PRACTICE	23.6	BACT-PSD

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CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GOOD COMBUSTION AND OXIDATION CATALYST	23.6	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	HOUSTON, TX	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION AND CO CATALYST	23.6	BACT-PSD
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	GOOD COMBUSTION TECHNOLOGY, CLEAN FUELS	23.7	BACT-PSD
DICKERSON	MONTGOMERY, MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	1,576	OXIDATION CATALYST	23.8	N/A
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	GCP	24.4	BACT-PSD
PSO SOUTHWESTERN POWER PLT	CADDO, OK	2/9/2007	?	GAS-FIRED TURBINES		COMBUSTION CONTROL	25.0	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION CONTROL PRACTICES	25.0	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GOOD COMBUSTION CONTROL PRACTICES	25.0	BACT-PSD
FRONT RANGE POWER COMPANY, LLC	FOUNTAIN, CO	11/13/2000	?	TURBINES, COMBINED CYCLE	1,384	COMBUSTION CONTROLS	25.0	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	GOOD COMBUSTION OF CLEAN FUELS	25.0	BACT-OTHER
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	GCP	25.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	GOOD COMBUSTION	25.0	BACT-PSD
CIPS - GRAND TOWER POWER STATION	ILLINOIS	2/25/2000	YES	(2) COMBINED CYCLE COMBUSTION TURBINE (UNITS 1&2)	2,365	GCP, GOOD DESIGN AND OPERATING PRACTICES	25.0	BACT-PSD
KENTUCKY PIONEER ENERGY, LLC - TRAPP	KENTUCKY	6/7/2001	?	(2) TURBINES, COMBINED CYCLE	1,765	GCP	25.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	?	(2) GAS TURBINES	1,908	GCP	25.0	BACT-PSD
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	GOOD DESIGN AND PRACTICES	25.0	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	?	(2) COGENERATION UNITS COMBINED CYCLE	320	DILUENT WATER INJECTION SYTEM BY USING A "QUIET COMBUSTOR" MULTI FUEL NOZZLE CAP ARRANGEMENT	25.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	5/16/2001	?	(2) GAS TURBINES (1-98A, 2-98A)	1,908	NONE INDICATED	25.0	BACT-PSD
PINE STATE POWER"	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	OXIDATION CATALYST	25.0	LAER
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	PROPER COMBUSTION	25.0	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	PROPER COMBUSTION CONTROL	25.0	BACT-PSD
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	LNB	25.0	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	(2) TURBINE/HRSG (CG-2, CG-3)	1,280	GCP	25.0	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/ AND W/O DUCT BURNER FIRING	672	DLN BURNERS	25.0	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	NONE INDICATED	25.0	BACT-OTHER
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	NONE INDICATED	25.0	OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	CO CATALYST	25.0	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	EFFICIENT & COMPLETE COMBUSTION	25.0	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACKS 1-8	1,400	NONE INDICATED	25.0	OTHER
DEER PARK ENERGY CENTER	HOUSTON	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	GCP	25.0	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	PROPER OPERATION AND COMBUSTING NAT GAS &/OR BYPRODUCT	25.0	BACT-PSD
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	FUEL GAS	30.0	
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	LNB	25.0	BACT-PSD
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		33.0	
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	GOOD OPERATING PRACTICES, USE OF CLEAN BURNING FUEL, LNB	25.0	BACT-PSD
				(4) COMBINED CYCLE GENERATION UNIT	1,464		35.5	
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	PROPER OPERATION	25.5	BACT-PSD
				(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360	NONE INDICATED	26.0	OTHER
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE, LA	3/2/1995	?	TURBINE/HRSG, GAS COGENERATION	450	GOOD COMBUSTION CONTROLS	26.3	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	NONE INDICATED	26.7	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,299		31.1	
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	COMBUSTION TURBINE, W/O DUCT BURNER	908	GCP AND COMBUSTION CONTROL	27.0	BACT-PSD
				TURBINE WITH DUCT BURNER	1,048		64.0	
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	NO	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	EFFICIENT COMBUSTION	27.2	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166	PROPER DESIGN AND GCP	28.0	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	GCP	28.3	BACT-PSD
FLORIDA POWER AND LIGHT	FL	6/5/1991	?	TURBINE, GAS, 4 EACH	MW	YES	30.0	
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	?	COMBINED CYCLE TURBINE (25 MW)	568	GCP	30.0	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	FLORIDA	2/1/2002	?	TURBINE, COMBINED CYCLE W AND W/O DUCT FIRING	1,990	NONE LISTED	30.3	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (SWH)	1,360		200.0	
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINTS AA-001, 002, 003	2,248	PROPER COMBUSTION	31.2	BACT-PSD
				(3) TURBINE, EMISSION POINTS AA-001, 002, 003 (<75% LOAD)	1,686	DLN COMBUSTION TECHNOLOGY	31.2	BACT-PSD
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	?	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	COMBUSTION CONTROLS	33.0	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	GCP	36.0	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	NONE LISTED	37.0	BACT-PSD
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP	37.2	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	EFFICIENT COMBUSTION	38.4	BACT-PSD
BLACK HILLS CORP./NEIL SIMPSON TWO	GILLETTE, WY	4/4/2003	?	TURBINE, COMBINED CYCLE & DUCT BURNER	320	EFFICIENT COMBUSTION PRACTICES	40.0	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	COMBUSTION CONTROLS	40.0	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	GOOD COMBUSTION CONTROL	40.0	BACT-PSD
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	EFFICIENT COMBUSTION	44.6	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	GOOD COMBUSTION CONTROL PRACTICES	48.0	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	NONE LISTED	48.0	BACT-OTHER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	NONE LISTED	60.0	BACT-PSD
LEDERLE LABORATORIES	PEARL RIVER, NY	9/15/1994	?	(2) GAS TURBINES (EP #S 00101&102)	110	STEAM INJECTION/GOOD COMBUSTION	66.0	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	COMBUSTION DESIGN AND CONSTRUCTION	69.0	BACT-PSD
WRIGHTSVILLE POWER FACILITY	WRIGHTSVILLE, AR	2/28/2000	?	(6)TURBINE, COMBUSTION GE LM6000	368	GOOD DESIGN, PROPER COMB TECHNIQUES 2% EXCESS O_2	88.3	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE	BATON ROUGE, LA	3/7/1997	YES	TURBINE/HSRG, GAS COGENERATION	450	EFFICIENT COMBUSTION	100.0	BACT-PSD
INEOS CHOCOLATE BAYOU FACILITY	BRAZORIA, TX	8/29/2006	?	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER)	280	PROPER COMBUSTION CONTROL. CO EMISSIONS FROM EACH TURBINE WILL NOT EXCEED 15 PPMVD AT 85% TO 100% OF BASE LOAD. TU	106.4	BACT-PSD
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	NONE INDICATED	107.0	BACT-OTHER
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848		156.0	
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	GAS TURBINE	500	GCP	132.0	BACT-PSD
				STACK EMISSIONS (TURBINE & DUCT BURNER)	610	COMBUSTION CONTROL	161.2	BACT-OTHER

Appendix E - Table E-3
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
CHAMBERS ENERGY L.P./ANP	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	GOOD COMBUSTION DESIGN/OPERATIONS CO CATALYST	0.4	LAER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACK (100% LOAD)	1,400	GOOD COMBUSTION AND DESIGN	0.4	BACT-PSD
				(8) COMBUSTION GS TURBINE GENERATORS STACK (50%-100% LOAD)	1,400		0.7	
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	GOOD COMBUSTION DESIGN AND OPERATIONS	0.4	BACT-PSD
				(2) GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		3.0	
CPV WARREN	WARREN, VA	1/14/2008	NO	(2) GE 207FA NG COMBINED-CYCLE TURBINES, WITH HRSG & DB	1,944	CEMS, GOOD COMB. PRAC. 2 STAGE LEAN PREMIX & SCR.	0.7	N/A
				(2) GE MODEL 7FA EACH RATED AT 180,000 KW W/ HRSG & DB	1,717	GCP AND OXIDATION CATALYST	0.7	N/A
				(2) SIEMENS MODEL SGT6-5000 TURBINES WITH 210 MMBTU/HR DB	2,204	GCP AND OXIDATION CATALYST	0.7	N/A
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	COMBUSTION CONTROLS	0.7	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	OXIDATION CATALYST	0.7	BACT
				(2) COMBINED CYCLE TURBINES W/ DUCT BURNER, GE 7FA	2,217		1.0	
				(2) COMBINED CYCLE TURBINES W/ POWER AUG, W/ DB, GE 7FA	2,217		1.4	
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181	OXIDATION CATALYST	0.7	NSPS
				(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		0.8	
				(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		0.8	
				(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181		1.8	
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.8	OTHER
BEAR MOUNTAIN LIMITED	BAKERSFIELD, CA	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	OXIDATION CATALYST	0.8	BACT-OTHER
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.8	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (75-99% LOAD, ALL TEMPS)	1,965	OXIDATION CATALYST FOR CO	0.9	BACT
				(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (50-74% LOAD, ALL TEMPS)	1,965		1.2	
				(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP < 60°F)	1,965		1.2	
				(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP 61-70°F)	1,965		1.3	
				(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP 71-80°F)	1,965		1.5	
				(2) TURBINES,ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP > 81°F)	1,965		3.0	
EMPIRE GENERATING CO. LLC	RENSSELAER, NY	6/23/2005	NO	(2) GE FRAME 7FA COMB TURBINES, HRSGS & STG.	2,099	OXIDATION CATALYST	1.0	LAER
				FUEL COMBUSTION (NATURAL GAS)	646	OXIDATION CATALYST	7.0	LAER
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	(2) TURBINE, COMBINED CYCLE	1,876	GCP	1.0	BACT-PSD
SITHE EDGAR DEV, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	OXIDATION CATALYST	1.0	BACT
				(2) MHI 501G COMBUSTION TURBINE W/ DUCT FIRING	2,955		1.7	
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE	2,964	CO CATALYST	1.0	OTHER
				(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202		1.7	
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	CLEAN FUEL	1.0	LAER
				(2) TURBINE, COMBINED CYCLE, DUCT FIRING	2,699		1.7	
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	1.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955		2.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE MHI/SW	1,400	GCP	1.0	BACT-PSD
				(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		4.6	
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	GCP	1.0	SIP
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	1.0	BACT-PSD
MANSFIELD MILL	MANSFIELD, LA	8/14/2001	?	GAS TURBINE/HRSG	654	OPERATION/MAINTENANCE, VENDOR GUARANTEE	1.0	BACT-PSD
CRESENT CITY POWER, LLC	ORLEANS, LA	6/6/2005	YES	NEW 600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	2,006	CO OXIDATION CATALYST AND GCP	1.1	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	1.1	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	1.1	BACT
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	OXIDATION CATALYST	1.1	OTHER
				(4) COMBINED CYCLE TURBINES, 50%-74%	1,404		1.9	
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	?	(2) TURBINE, COMBINED CYCLE	1,376	OXIDATION CATALYST	1.1	BACT-OTHER
				(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883		2.5	
LAKE ROAD GENERATING COMPANY,L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	OXIDATION CATALYST FOR CO	1.1	BACT
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	1.1	BACT-PSD
PROGRESS ENERGY FLORIDA (PEF)	PINELLAS, FL	1/26/2007	NO	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	493	GOOD COMBUSTION	1.2	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	1.2	LAER
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	NONE INDICATED	1.2	BACT-PSD
CONECTIV BETHLEHEM, INC.	PENNSYLVANIA	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	NONE INDICATED	1.2	BACT-OTHER
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINE W/ AND W/O DUCT BURNERS GT-HRSG 1-4	1,360	GOOD COMBUSTION DESIGN & OPERATIONS	1.2	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(6) GAS FUELED TURBINES, STACK 1-6	2,200	GOOD COMBUSTION DESIGN AND OPERATIONS	1.2	BACT-PSD
				(6) GAS FUELED TURBINES, STACK 1-6, W/ EVAP COOLER OR STEAM INJ.	2,200		3.0	
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE (75% LOAD)	2,010	THE USE OF OXIDATION CATALYST	1.2	LAER
				(4) COMBUSTION TURBINE COMBINED CYCLE (50% LOAD)	2,010		3.0	
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, NO DUCT BURNER FIRING	1,937	GOOD AIR POLLUTION CONTROL PRACTICES	1.2	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		2.3	
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	GOOD AIR POLLUTION CONTROL PRACTICES	1.2	BACT-PSD
				(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		2.3	
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	CO CATALYST & EFFICIENT COMBUSTION TECHNIQUES	1.2	LAER
				(3) COMBINED CYCLE TURBINES	2,049		2.4	
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360	GOOD COMBUSTION. NATURAL GAS ONLY	1.2	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945		6.2	
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	OXIDATION CATALYST	1.2	OTHER
				(1) COMBINED CYCLE COMBUSTION TURBINE, W/ DUCT BURNER	2,423		7.6	
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	YES	TURBINE, COMBINED CYCLE, DUCT BURNER CC4	1,040	OXIDATION CATALYST	1.2	LAER
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	OXIDATION CATALYST FOR CO	1.2	BACT
FLORIDA POWER AND LIGHT	DADE, FL	2/8/2005	NO	(4) GE MODEL FA TURBINES (170 MW EACH), (4) HRSGS, (1) STG	1,360	EFFICIENT COMBUSTION	1.3	None
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE	1,827	GCP	1.3	BACT-PSD
				(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		6.6	
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	EFFICIENCT COMBUSTION	1.3	BACT
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	OXIDATION CATALYST	1.3	LAER
TECO BAYSIDE POWER STATION	TAMPA, FL	3/30/2001	YES	(7) TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	1.3	BACT-PSD
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	GCP AND OXIDATION CATALYST	1.3	LAER
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	GOOD COMBUSTION AND VOC CATALYST	1.3	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	1.3	BACT-PSD
				(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		2.3	
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE	1,600	GCP	1.3	BACT-PSD
				(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,095		4.0	
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYCLE	1,600	GCP	1.3	BACT-OTHER

Appendix E - Table E-3
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
				(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER OR POWER AUG.	1,360		4.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE GE	1,400	GCP	1.3	BACT-PSD
				(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		4.9	
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	GOOD COMBUSTION DESIGN AND OPERATIONS	1.3	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464		5.6	
PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	GCP WITH DLN COMBUSTORS (NAT GAS)	1.3	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP	1.3	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	1.3	BACT-PSD
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	CATALYTIC REDUCTION	1.4	OTHER
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (GE)	1,360	GCP	1.4	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	YES	TURBINE, COMBINED CYCLE	2,040	NONE INDICATED	1.4	BACT-PSD
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	OXIDATION CATALYST AND GCP	1.4	BACT-PSD
MOUNTAINVIEW POWER	SAN BERNARDINO, CA	5/22/2001	YES	(4) TURBINE, COMBINED CYCLE	1,991	OXIDATION CATALYST	1.4	LAER
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES	1,611	NONE INDICATED	1.4	
FPL SANFORD PLANT	DEBARY, FL	9/14/1999	YES	(4) COMBUSTION TURBINES COMBINED CYCLE	1,776	GCP	1.4	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	COMBUSTION CONTROLS	1.4	BACT-OTHER
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	GCP	1.4	BACT-OTHER
CP & L - RICHMOND CO. FACILITY	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	COMBUSTION CONTROL	1.4	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	COMBUSTION CONTROL	1.4	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	PIPELINE QUAL NAT GAS, GOOD ENGINEERING PRACTICE	1.4	BACT-PSD
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP	1.4	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES TURBINE W/ AND W/O DUCT BURNER	1,360	GCP	1.4	BACT-PSD
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	GOOD COMBUSTION DESIGN AND OPERATIONS	1.4	BACT-PSD
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		2.4	
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYCLE (50%-100%)	3,630	CLEAN FUEL - NATURAL GAS	1.4	LAER
				(2) TURBINES, COMBINED CYCLE (<50%)	3,630		2.5	
				(2) TURBINES, COMBINED CYCLE, W/ STEAM INJECTION	3,630		3.5	
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP	1.4	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		3.0	
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	GCP	1.4	LAER
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191		3.1	
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	?	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL - NATURAL GAS	1.4	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/ STEAM INJECTION	1,815		3.5	
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	?	TURBINE, COMBINED CYCLE	1,973	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	1.4	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		4.0	
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE	1,696	GOOD COMBUSTION	1.4	BACT-PSD
				TURBINE, COMBINED CYCLE & DUCT BURNER	1,696		4.0	
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	GE COMBUSTION TURBINE W/O DUCT BURNERS	1,705	GCP AND DLN COMBUSTOR	1.4	BACT-PSD
				GE COMBUSTION TURBINE & DUCT BURNERS	1,705		4.1	
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	LNB	1.4	BACT-PSD
				(4) COMBINED CYCLE GENERATION UNIT	1,464		4.8	
CONED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OXIDATION CATALYST	1.4	LAER
				(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		5.0	
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	GOOD OPER PRACTICES & USE OF NATURAL GAS AS FUEL	1.4	BACT-PSD
				(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		5.2	
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650	CATALYTIC OXIDIZER PROVIDES SOME CONTROL FOR VOC	1.4	BACT-PSD
				(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300		5.4	
				(3) TURBINE, COMBINED CYCLE AND DUCT BURNER, POWER AUG.	2,300		12.4	
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	STATE OF THE ART COMBUSTER DESIGN, GCP	1.4	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		5.7	
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	GCP	1.4	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		20.0	
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP	1.4	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	1.4	OTHER
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	OXIDATION CATALYST	1.4	BACT
FLORIDA POWER AND LIGHT COMPANY	WEST PALM BEACH, FL	1/10/2007	NO	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	389	None	1.5	BACT-PSD
MINNESOTA MUNICIPAL POWER AGENCY	RICE, MN	6/5/2007	NO	COMBINED CYCLE COMB TURBINE GENERATOR W/ 249 MMBTU/H DB	1,758	None	1.5	BACT-PSD
BERRIEN ENERGY, LLC	BERRIEN, MI	4/13/2005	YES	3 COMBUSTION TURBINES AND DUCT BURNERS	1,584	CATALYTIC OXIDIZER	1.6	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	GCP	1.6	OTHER
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	OXIDATION CATALYST	1.6	LAER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	1.6	LAER
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE	1,944	GCP	1.6	BACT-PSD
				(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944		2.9	
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	GCP	1.6	BACT-OTHER
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	GOOD COMBUSTION DESIGN AND OPERATIONS	1.6	BACT-PSD
				(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		2.2	
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	1.7	BACT-OTHER
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	GCP	1.7	BACT-OTHER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	GOOD COMBUSTION CONTROL PRACTICES	1.7	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION TECHNOLOGY, CLEAN FUEL	1.7	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	COMBUSTION TECHNOLOGY/CLEAN FUELS	1.7	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	SCR HAS SOME CONTROL OF VOC	1.7	BACT-PSD
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		11.2	
SOUTHERN COMPANY/GEORGIA POWER	COBB, GA	1/7/2008	NO	6 TURBINES, 254 MW EACH (NOT INCLUDING STEAM RECOVERY),	2,032	OXIDATION CATALYST	1.8	LAER
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	GOOD COMBUSTION CONTROL	1.8	BACT-PSD
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	NONE INDICATED	1.8	LAER
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	2 CATALYTIC CONTROL DEVICES	1.8	BACT-OTHER
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE, 70% LOAD	1,492	GCP	1.8	BACT-PSD
				(2) TURBINE, COMBINED CYCLE	2,132		2.0	
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,937	GCP	1.8	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	NONE INDICATED	1.8	BACT-PSD
				(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		3.7	
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707	GCP	1.8	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097		3.8	

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CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE INDICATED	1.8	BACT-PSD
				(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		3.9	
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMBUSTION CLEAN FUELS	1.9	BACT-OTHER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	GOOD COMBUSTION DESIGN & OPERATION	1.9	BACT-PSD
NORTHERN STATES POWER CO. DBA XCEL ENERGY	RAMSEY, MN	8/12/2005	YES	2 COMBINED-CYCLE COMBUSTION TURBINES	2,640	GOOD COMBUSTION PRACTICES.	2.0	BACT-PSD
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	YES	TURBINE, COMBINED CYCLE, DUCT BURNER CC5	4,240	OXIDATION CATALYST	2.0	BACT-OTHER
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	?	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	CATALYTIC OXIDATION AND GCP	2.0	BACT-OTHER
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	GCP, NATURAL GAS FUEL	2.0	BACT-PSD
				TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791		2.3	
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO, CA	8/19/1994	?	TURBINE GAS COMBINE CYCLE SIEMENS V84.2	1,257	OXIDATION CATAYLST	2.0	BACT
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	COMBUSTION CONTROLS AND OXIDATION CATALYST	2.0	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	OXIDATION CATAYLST	2.0	LAER
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	COMBUSTION DESIGN, GCP	2.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION DESIGN, GCP	2.0	BACT-PSD
AUGUSTA ENERGY CENTER	AUGUSTA, GA	10/28/2001	?	(3) TURBINE, COMBINED CYCLE	2,000	CATALYTIC OXIDATION	2.0	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	CATALYTIC OXIDATION	2.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE, GA	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	GCP	2.0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES"	FLEETWOOD, PA	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	GCP	2.0	BACT-OTHER
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	PROPER COMBUSTION CONTROL	2.0	LAER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	GOOD COMBUSTION PRACTICES	2.0	BACT-OTHER
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	FIRING PIPELINE NAT GAS AND OXIDATION CATALYST	2.0	BACT-OTHER
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	NONE INDICATED	2.0	OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-OTHER
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	2.0	OTHER
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	GCP AND DESIGN	2.0	BACT-PSD
				(2) TURBINES, COMBINED CYCLE DUCT BURNERS	1,985		3.7	
GREGORY POWER FACILITY	COSTA MESA, TX	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	GOOD COMBUSTION DESIGN AND PRACTICES	2.0	BACT-PSD
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		4.9	
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK COMBINED GT/HRSG&DB 1180	310	GCP	2.0	BACT-OTHER
				COGEN STACK TURBINE ONLY	310		7.0	
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	YES	(2) COMBINED-CYCLE TURBINE	2,311	GOOD COMB CONTROL & OXIDATION CATALYST	2.0	BACT-PSD
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO, CA	8/19/1994	?	TURBINE, GAS COMBINED CYCLE LM6000	421	OXIDATION CATALYST	2.0	BACT
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440	NONE INDICATED	2.1	BACT-PSD
				(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440		16.3	
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION. NATURAL GAS ONLY	2.1	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	GCP	2.1	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	FIRING OF NATURAL GAS ONLY IN THE CTG/HRSGS AND THE	2.1	BACT-PSD
				(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DUCT BURNER	1,900	USE OF GOOD COMBUSTION CONTROL	2.7	
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	GOOD COMBUSTION CONTROL PRACTICES	2.2	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	CATALYTIC OXIDATION	2.2	BACT-OTHER
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	GOOD COMBUSTION AND OXIDATION CATALYST	2.2	
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000	GCP	2.2	LAER
CALPINE CORP.	WELD, CO	5/2/2006	YES	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	2,400	GCP AND OXIDATION CATALYST.	2.3	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	2.3	LAER
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440	COMBUSTION CONTROLS AND OXIDATION CATALYST	2.3	BACT-PSD
				(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440		9.4	
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/O DUCT BURNER FIRING	672	GOOD COMBUSTION	2.4	BACT-OTHER
				TURBINE/HRSG W/ DUCT BURNER FIRING	672		18.5	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE I: TURBINES E-1+E-2 W/O HRSG	720	NONE INDICATED	2.4	OTHER
				(2) CASE II: TURBINES E-1+E-2 W/ HRSG	720		6.7	
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	NO	(3) TURBINE, COMBINED CYCLE	1,467	OXIDATION CATALYST	2.4	LAER
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	GCP	2.4	LAER
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	CATALYTIC OXIDATION AND GCP	2.4	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	PIPELINE QUALITY NAT GAS	2.6	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	GCP	2.7	SIP
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	GCP	2.7	BACT-PSD
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	NONE INDICATED	2.7	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	2.7	BACT-PSD
SALT RIVER PROJ./ DESERT BASIN GENERATING PROJ.	PHOENIX, AZ	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	GCP	2.8	BACT-PSD
				TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		5.7	
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	COMBUSTION CONTROL AND USE OF NATURAL GAS	2.8	BACT-OTHER
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	2.8	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	2.8	OTHER
SATSOP COMBUSTION TURBINE PROJECT"	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	OXIDATION CATALYST	2.8	BACT-PSD
PINNACLE WEST ENERGY CORP/REDHAWK GEN. FACILITY	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	GOOD COMBUSTION	2.8	BACT-PSD
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	CLEAN FUEL. GOOD COMBUSTION AND DESIGN	2.9	BACT-PSD
				(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		6.1	
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	VOC AS NMHC	2.9	BACT-PSD
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	CATALYTIC OXIDATION	2.9	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	CATALYTIC OXIDATION	3.0	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION	3.0	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	OXIDATION CATALYST	3.0	BACT-OTHER
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	?	(2) TURBINE, COMBINED CYCLE (SWH)	1,360	GCP	3.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	3.0	BACT-PSD
LOWER MOUNT BETHEL ENERGY, LLC	PENNSYLVANIA	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	OXIDATION CATALYST	3.0	LAER
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	EFFECTIVE FUEL COMBUSTION	3.1	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	EFFICIENT COMBUSTION	3.1	BACT-PSD
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	GAS TURBINE	500	NONE INDICATED	3.1	BACT-OTHER
				STACK EMISSIONS (TURBINE & DUCT BURNER)	610		31.2	
SEPCO	RIO LINDA, CA	10/5/1994	?	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920	OXIDATION CATALYST	3.1	BACT
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	NONE INDICATED	3.2	BACT-PSD
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	NONE INDICATED	3.2	OTHER
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	COMBUSTION DESIGN AND GOOD OPERATING PRACTICE	3.3	BACT-OTHER

Appendix E - Table E-3
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	OXIDATION CATALYST	3.5	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	3.5	LAER
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	COMBUSTION CONTROLS	3.5	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TENNESSEE	2/1/2002	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,990	GCP	3.5	BACT-PSD
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735	GCP	3.6	BACT-PSD
				(2) TURBINES, COMBUSTION	1,735		12.5	
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	NONE INDICATED	3.7	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	NONE INDICATED	3.8	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	GCP	3.8	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	NONE INDICATED	3.9	BACT-PSD
NEW ATHENS GENERATING CO. LLC	GREENE, NY	1/19/2007	NO	3 WESTINGHOUSE MODEL 501G GAS COMBINED CYCLE TURBINES	3,100	GOOD COMBUSTION CONTROL	4.0	LAER
SIERRA PACIFIC POWER COMPANY	STOREY, NV	8/16/2005	NO	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG & DB	2,448	OXIDATION CATALYST	4.0	BACT-PSD
				TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG & DB	2,448	OXIDATION CATALYST	4.0	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	EFFICIENT COMBUSTION TECHNIQUES	4.0	LAER
HOT SPRINGS POWER PROJECT	ARIZONA	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	CATALYTIC OXIDIZER	4.0	BACT-PSD
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	CATALYTIC OXIDIZER	4.0	LAER
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	GCP, OXIDATION CATALYST	4.0	BACT-PSD
CHOCTAW GAS GENERATION, LLC	HOUSTON, TX	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	GCP	4.0	BACT-PSD
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	FIRING NAT GAS, AND DLN BURNERS	4.0	BACT-OTHER
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	GCP	4.0	BACT-OTHER
INDECK-NILES, LLC	NILES, MI	12/2/2001	?	(4) GAS TURBINES COMBINED CYCLE	2,152	NONE INDICATED	4.0	BACT-PSD
				(4) GAS TURBINES COMBINED CYCLE W/ DUCT BURNER	2,152		5.2	
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224	OXIDATION CATALYST	4.0	LAER
				COMBUSTION TURBINE W/ HEAT RECOVERY BOILER (75% LOAD)	1,224		7.6	
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE	2,096	NONE INDICATED	4.2	BACT-PSD
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	GCP	4.5	BACT-PSD
NORTHERN STATES POWER CO. DBA XCEL ENERGY	RAMSEY, MN	5/16/2006	YES	TWO COMBUSTION TURBINES	1,885	GOOD COMBUSTION PRACTICES	4.6	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	COMBUSTION CONTROL	4.6	BACT-OTHER
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	GCP	4.7	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	GCP	4.7	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GCP	4.7	BACT-PSD
PEDRICKTOWN COGENERATION PLANT (PCLP)	MAYS LANDING, NJ	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	NONE INDICATED	4.7	BACT-PSD
CIPS - GRAND TOWER POWER STATION	ILLINOIS	2/25/2000	YES	(2) COMBINED CYCLE COMBUSTION TURBINE (UNITS 1+2)	2,347	GCP	4.8	BACT-PSD
SOUTHWEST ELECTRIC POWER COMPANY	SHREVEPORT, LA	3/20/2008	YES	(2) COMBINED CYCLE GAS TURBINES	1,055	PROPER OPERATING PRACTICES	4.9	BACT-PSD
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	?	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	CO CATALYST, GOOD COMBUSTION	4.9	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	GOOD COMBUSTION. NATURAL GAS ONLY	4.9	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	EFFICIENT COMBUSTION	4.9	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC (DRAFT)	MIDDLESEX, CT	2/25/2008	NO	(2) SIEMENS SGT6-5000F TURBINES (HRSG & NG DUCT BURNER)	1,071	EMISSION RATES NOT BASED ON RED. FROM CO CAT.	5.0	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	COMBUSTION CONTROLS	5.0	BACT-PSD
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	GCP	5.0	BACT-OTHER
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	GCP	5.2	BACT-PSD
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	OXIDATION CATALYST	5.2	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	5.2	BACT-OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,299	GOOD COMBUSTION CONTROLS	5.2	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(2) HRSG/TURBINES 001&002	1,400	GOOD COMBUSTION CONTROLS	5.3	LAER
DUKE ENERGY FAYETTE, LLC	MASONTOWN	1/30/2002	?	(2) TURBINE, COMBINED CYCLE	2,240	OXIDATION CATALYST	5.3	LAER
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	GCP/DESIGN	5.3	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	EFFICIENT COMBUSTION	5.5	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP WITH DLN COMBUSTOR	5.6	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	GOOD COMBUSTION DESIGN AND OPERATIONS	5.6	OTHER
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GCP	5.6	BACT-PSD
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844	GCP AND EFFICIENT PROCESS DESIGN	5.7	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GEN STATION	BURNSVILLE, MN	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	USE OF NATURAL GAS AS THE EXCLUSIVE FUEL	5.7	BACT-PSD
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	GOOD COMBUSTION CONTROL	5.7	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844	GCP AND EFFICIENT PROCESS DESIGN	5.7	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(2) HRSG/TURBINES 003&004	1,400	GOOD COMBUSTION CONTROLS	5.7	LAER
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	NONE INDICATED	6.0	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	CATALYTIC OXIDATION	6.0	BACT-PSD
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	OXIDATION CATALYST AND GCP	6.0	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	EFFICIENT COMBUSTION	6.1	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	PROPER COMBUSTION PRACTICES	6.2	LAER
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	EFFICIENT COMBUSTION PRACTICES	6.2	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NATURAL GAS COMBUSTION	6.2	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON, AL	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	EFFICIENT COMBUSTION	6.4	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	HOUSTON, AL	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	EFFICIENT COMBUSTION	6.4	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	CLEAN FUEL -- NATURAL GAS ONLY	6.6	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	7.0	BACT-OTHER
INTERNATIONAL PAPER	MANSFIELD, LA	2/24/1994	?	TURBINE/HRSG, GAS COGEN	338	COMBUSTION CONTROLS, FUEL SELECTION	7.0	BACT-OTHER
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	COMBUSTION CONTROL	7.0	BACT-PSD
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	OPERATIONAL CONTROLS	7.0	BACT-PSD
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	DLN COMBUSTION	7.0	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	GCP/DESIGN	7.0	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	NONE INDICATED	7.0	OTHER
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE	457	LNB	7.2	BACT-PSD
				COMBUSTION TURBINE W/ DUCT BURNER	623		10.0	
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (<75% LOAD)	1,480	GCP	7.3	BACT-PSD
				TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480		13.5	
RELIANT ENERGY- CHANNELVIEW COGENERATION	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	7.4	OTHER
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	NONE INDICATED	7.5	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	NONE INDICATED	8.4	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		10.1	
DUKE ENERGY-JACKSON FACILITY	ARIZONA	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION CONTROL	8.4	BACT-PSD
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	?	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	GCP/CO OXIDATION CATALYST	8.4	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	CATALYTIC OXIDATION	8.4	BACT-PSD

Appendix E - Table E-3
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	NONE INDICATED	8.6	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	8.9	BACT-OTHER
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	9.0	BACT-PSD
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINT AA-001,002,003 (75%-100% LOAD)	2,248	NONE INDICATED	9.3	BACT-PSD
				(3) TURBINE, EMISSION POINT AA-001,002,003 (<75% LOAD)	2,248		10.0	
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	EFFICIENT COMBUSTION	9.4	BACT-PSD
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	CATALYTIC AFTERBURNER	9.4	BACT-PSD
CONTINENTAL ENERGY SERVICES, INC., SILVER BOW GEN	BUTTE, MT	6/7/2002	NO	(4) COMBINED CYCLE CT	1,400	NONE INDICATED	9.5	OTHER
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166	GCP AND COMBUSTION CONTROL	9.6	BACT-PSD
				TURBINE, COMBINED CYCLE W DUCT BURNER	2,516		12.6	
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	NONE INDICATED	9.6	OTHER
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	PROPER COMBUSTION CONTROL	9.7	LAER
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	GOOD OPERATING PRACTICE	9.7	BACT-PSD
MIRANT WYANDOTTE LLC	MICHIGAN	7/25/2001	YES	(2) GAS TURBINES COMBINED CYCLE	2,205	CAT-OX SYSTEM	10.0	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200	CATALYTIC OXIDIZER & GOOD COMBUSTION TECHNIQUES	10.0	BACT-OTHER
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	EFFICIENT COMBUSTION	10.2	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376	NONE INDICATED	11.6	BACT-PSD
ALABAMA POWER CO. - THEODORE COGENERATION	THEODORE, AL	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	EFFICIENT COMBUSTION	12.5	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP	13.6	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	GCP	13.7	BACT-OTHER
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848	EFFICIENT COMBUSTION	15.0	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	BEST COMBUSTION CONTROL PRACTICES	15.5	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP	17.1	BACT-OTHER
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	EFFICIENT & COMPLETE COMBUSTION	19.3	LAER
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	GOOD COMBUSTION DESIGN AND OPERATIONS	19.7	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	GOOD COMBUSTION AND DLN TECHNOLOGY	20.9	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	22.6	BACT-OTHER
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	EFFICIENT COMBUSTION PRACTICES	22.8	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GENERATING PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	DESIGN	24.9	BACT-PSD
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	PROPER COMBUSTION	28.4	BACT-PSD
INEOS USA LLC	BRAZORIA, TX	8/29/2006	YES	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS)	140	PROPER COMBUSTION CONTROL	34.2	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-4
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	(2) COMBINED CYCLE TURBINES, 75% LOAD	2,160	CLEAN BURNING FUEL AND EFFICIENT COMBUSTION	0.00130	BACT
			(2) COMBINED CYCLE TURBINES	2,160		0.00930	
			(2) COMBINED CYCLE TURBINES, 60% LOAD	2,160		0.01280	
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TWP, NJ	4/1/1991	TURBINES (NATURAL GAS) (2)	1190	TURBINE DESIGN	0.0023	BACT-OTHER
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	(2) COMBUSTION TURBINES #1 & #2	1,836	NONE INDICATED	0.00245	BACT-PSD
TRANSALTA CENTRALIA GENERATION LLC	CENTRALIA, WA	2/22/2002	(4)TURBINE/HRSG	1,504	GCP	0.00273	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC.	PRYOR, OK	3/24/1999	ELECTRIC GENERATION, TURBINE, NATURAL GAS	530	COMBUSTION CONTROLS	0.0030	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	USE OF LOW ASH FUEL (NAT GAS) COMBUSTION CONTROLS	0.00300	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	(2) TURBINES, COMBINED CYCLE	2,640	GCP LOW SULFUR FUEL	0.00306	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	EFFICIENT COMBUSTION	0.00350	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.00353	OTHER
FORSYTH ENERGY PLANT	NC	9/29/2005	TURBINE, COMBINED CYCLE NATURAL GAS (3)	1844.3		0.0037	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	(2) TURBINES, COMBINED CYCLE	1,915	CLEAN BURNING FUELS, GCP	0.00381	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	(2) TURBINES, COMBINED CYCLE	1,338	CLEAN FUEL -- NATURAL GAS ONLY	0.00390	BACT-PSD
INDECK-NILES, LLC	NILES, MI	12/2/2001	(4) GAS TURBINES COMBINED CYCLE	2,152	NONE INDICATED	0.00395	BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK, NY	6/18/1992	COMBUSTION TURBINES (2) (252 MW)	1173	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	0.0040	BACT-OTHER
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	NATURAL GAS < 1 GR S/100 SCF OF GAS	0.00420	BACT-PSD
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	GOOD COMBUSTION AND FIRING NATURAL GAS	0.00420	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMBUSTION AND CLEAN FUELS	0.00431	BACT-OTHER
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	LOW ASH FUELS, GCP	0.00432	BACT-PSD
PINE STATE POWER	JAY, ME	6/30/1994	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	CLEAN FUEL	0.00444	BACT-PSD
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	(2) TURBINES, COMBUSTION, W/ AND W/O DUCT BURNER	1,735	GCP AND NATURAL GAS FUEL	0.00450	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	TURBINE	1,984	PIPELINE QUALITY NAT GAS	0.00454	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	CLEAN FUELS	0.00462	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	NONE INDICATED	0.00474	LAER
			(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DB	1,900		0.006105	
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	(2) COMBINED CYCLE TURBINES	1,884	PIPELINE QUALITY GAS, CLOSE MONITORING/CONTROL/COMB	0.00478	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	TURBINE, COMBINED CYCLE	1,360	CLEAN FUELS	0.00490	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2,534	DLN TECHNOLOGY IN CONJUNCTION WITH SCR	0.0050	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE, RI	4/13/1992	TURBINE, GAS AND DUCT BURNER	1,360	USE OF NATURAL GAS	0.0050	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	(3) TURBINES, COMBINED CYCLE	1,867	NATURAL GAS ONLY EFFICIENT COMBUSTION	0.00500	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	0.00500	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	0.00500	BACT-PSD
			(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		0.00542	
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	TURBINE, COMBINED CYCLE, DUCT BURNER CC5	4,240	USE OF NATURAL GAS AND GOOD COMBUSTION	0.00510	LAER
CPV WARREN	VA	1/14/2008	ELECTRIC GENERATION - SCENARIO 2	1,717	WITHOUT DUCT FIRING	0.0051	UNKNOWN
			ELECTRIC GENERATION - SCENARIO 1			0.0073	N/A
VINEYARD ENERGY CENTER, LLC	VINEYARD, UT	5/11/2004	(3) SWPC 501F COMBUSTION TURBINES	1,738	NONE INDICATED	0.00518	BACT
			(3) SWPC 501F COMBUSTION TURBINES, W/ DUCT BURNER	2,400		0.00631	
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	COMBUSTION TURBINE (1 OR 2)	1,700	GCP	0.00529	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	GCP. USE OF NG/LPG	0.00530	BACT-PSD
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	TURBINE, COMBINED CYCLE, DUCT BURNER CC4	1,040	USE OF NATURAL GAS AND GCP	0.00550	LAER
CAROLINA POWER AND LIGHT - RICHMOND CO. FACILITY	RALEIGH, NC	12/21/2000	(2) TURBINES, COMBINED CYCLE	1,628	COMBUSTION CONTROL	0.00550	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	(2) TURBINE, COMBINED CYCLE	1,628	COMBUSTION CONTROL	0.00550	BACT-PSD
CON ED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	NONE INDICATED	0.00554	LAER
			(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		0.00786	
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	(2) GAS TURBINES	1,611	GOOD COMBUSTION CONTROL	0.00559	LAER
TIGER BAY LP	FT. MEADE, FL	5/17/1993	TURBINE, GAS	1,615	GOOD COMBUSTION PRACTICES	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH, FL	6/5/1991	TURBINE, GAS, 4 EACH	400	COMBUSTION CONTROL	0.0056	BACT-PSD
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	0.00560	BACT-PSD
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GCP	0.00600	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	GOOD COMBUSTION AND FIRING NATURAL GAS	0.00609	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	GCP	0.00610	LAER
SARANAC ENERGY COMPANY	PLATTSBURGH, NY	7/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123	COMBUSTION CONTROLS	0.0062	BACT-OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	COMBUSTION TURBINE COMBINED CYCLE	1,299	GOOD COMBUSTION CONTROLS	0.00624	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB, GOOD COMBUSTION	0.00625	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TENNESSEE	2/1/2002	TURBINE, COMBINED CYCLE W/O DUCT FIRING	1,990	CLEAN FUELS, GCP	0.00628	BACT-PSD
			TURBINE, COMBINED CYCLE W/ DUCT FIRING	1,990		0.00879	
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	(1) COMBINED CYCLE GAS TURBINE	1,742	CLEAN FUELS, GCP	0.00631	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS, COMBUSTION CONTROLS	0.00631	BACT
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS, COMBUSTION CONTROLS	0.00631	BACT
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	FIRING NAT GAS	0.00643	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	TURBINE, COMBINED CYCLE	1,700	COMBUSTION CONTROLS, LOW SULFUR FUELS	0.00647	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	COMBINED CYCLE COMBUSTION TURBINE	1,700	INHERENTLY CLEAN FUELS	0.00647	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.00650	BACT
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	TURBINE, COMBINED CYCLE	1,360	GCP, CLEAN FUEL	0.00650	BACT-PSD
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	(2) COMBINED-CYCLE TURBINE	2,311	USE OF PIPELINE QUALITY NATURAL GAS AND GCP	0.00650	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS GOOD COMBUSTION	0.00655	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS GOOD COMBUSTION	0.00655	BACT-PSD
SALT RIVER / DESERT BASIN GENERATING PROJECT	PHOENIX, AZ	9/10/1999	TURBINE, COMBINED CYCLE	2,320	GCP	0.00659	BACT-PSD
			TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		0.00991	
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440	NONE INDICATED	0.00660	BACT-PSD
			(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440		0.00910	
LORDSBURG L.P.	LORDSBURG, NM	6/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	800	(LESS THAN 0.05% BY WT.)	0.0066	BACT-PSD
ONETA GENERATING STA	OKLAHOMA	1/21/2000	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW ASH FUELS	0.00662	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	COMBINED CYCLE TURBINE (25 MW)	568	EFFICIENT OPERATION OF THE COMBUSTION TURBINE	0.00680	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	(3) TURBINES, COMBINED CYCLE	2,375	USE OF NATURAL GAS/CLEAN FUEL	0.00682	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	CASE I: TURBINE E-1 W/O HRSG	720	NONE INDICATED	0.00694	OTHER
			CASE II: TURBINE E-1 W/ HRSG	720		0.00750	
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	USE OF NO-ASH FUEL AND EFFICIENT COMBUSTION	0.00700	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON, AL	12/11/2001	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL	0.00720	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	HOUSTON, AL	10/23/2001	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	EFFICIENT COMBUSTION	0.00720	BACT-PSD
KYRENE GENERATING STATION, SALT RIVER PROJECT	PHOENIX, AZ	3/14/2001	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	NONE INDICATED	0.00720	LAER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	(2) TURBINE, COMBINED CYCLE	2,046	LOW ASH FUEL, NG	0.00720	BACT-OTHER
GULF STATES UTILITIES COMPANY - LOUISIANA STATION	BATON ROUGE, LA	2/7/1996	NO.4 TURBINE/HRSG	1,573	NONE INDICATED	0.00725	OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.00740	BACT
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-ASH FUEL - NATURAL GAS	0.00750	BACT-OTHER
			COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		0.00929	
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	7/25/2001	(2) GAS TURBINES COMBINED CYCLE	2,205	NONE INDICATED	0.00762	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200	GCP AND USE OF PIPELINE QUALITY NATURAL GAS	0.00764	BACT-PSD

Appendix E: Table E-4
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	(3) TURBINE/HRSG NO.1,2,3	3,168	FIRING NAT GAS	0.00783	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	GOOD COMBUSTION	0.00787	BACT-PSD
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	FIRING NAT GAS	0.00795	BACT-PSD
			(2)GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		0.00910	
WALLULA POWER PLANT	WASHINGTON	1/3/2003	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	NONE INDICATED	0.00800	BACT-OTHER
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	FIRING NAT GAS	0.00805	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	COMBUSTION CONTROL & PIPELINE-QUALITY NAT GAS	0.00809	BACT-OTHER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	(3) COMBUSTION TURBINES 7,8,9	360	GCP	0.00833	BACT-PSD
MANSFIELD MILL	MANSFIELD, LA	8/14/2001	GAS TURBINE/HRSG	654	NATURAL GAS FIRING	0.00840	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	NONE INDICATED	0.00850	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	(2) COMBUSTION TURBINES	1,840	GOOD COMBUSTION	0.00858	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	FIRING NAT GAS	0.00865	BACT-PSD
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	(4) TURBINES, COMBINED CYCLE GE (50%-100%)	1,400	GCP	0.00876	BACT-PSD
			(4) TURBINES, COMBINED CYCLE GE (100%)	1,400		0.01007	
			(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		0.01204	
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	TURBINE, GAS COMBINED CYCLE	1,344	COMBUSTION OF CLEAN FUELS	0.00890	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	COMBUSTING NATURAL GAS	0.00890	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON, RI	2/13/1998	COMBUSTION TURBINE, NATURAL GAS	2,120	GOOD COMBUSTION	0.0089	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	(8) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NATURAL GAS ONLY	0.00900	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GCP	0.00900	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	NATURAL GAS	0.00900	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	(2) TURBINE, COMBINED CYCLE	1,488	NONE INDICATED	0.00900	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	0.00900	BACT-OTHER
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	NONE INDICATED	0.00900	BACT-PSD
			UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		0.01025	
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	TURBINE, COMBINED CYCLE	2,094	GCP	0.00907	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,973	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	0.00912	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		0.01062	
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	0.00915	BACT-OTHER
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	(2) TURBINE, COMBINED CYCLE	1,962	GCP. DRIFT ELIMINATORS	0.00917	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707	GCP	0.00926	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097		0.00939	
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.00932	OTHER
MIDDLETON FACILITY	BOISE, ID	10/19/2001	(2) GAS TURBINES WITH DUCT BURNERS	2,097	REASONABLE POLLUTION PREVENTION PRECAUTIONS	0.00939	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION TECHNOLOGY	0.00942	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	TURBINE, NO DUCT BURNER FIRING	1,937	NONE INDICATED	0.00945	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		0.01146	
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	PIPELINE QUALITY NATURAL GAS AND GCP	0.00955	BACT-PSD
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	(2) TURBINE, COMBINED CYCLE	1,827	GCP	0.00958	BACT-PSD
			(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		0.00960	
LAWRENCE ENERGY	OHIO	9/24/2002	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440	BURNING NATURAL GAS	0.00960	BACT-PSD
			(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440		0.01010	
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	0.00971	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955	NONE INDICATED	0.00972	BACT-PSD
			(2) TURBINE, COMBINED CYCLE	1,360		0.01103	
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN	6/15/2001	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	0.00980	BACT-OTHER
			(3) COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	2,400		0.01060	
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	USE OF LOW ASH FUEL	0.00994	BACT-PSD
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	NONE INDICATED	0.01000	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	TURBINE, COMBINED CYCLE	1,876	CLEAN FUEL AND GCP	0.01000	BACT-PSD
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	CLEAN FUEL - NATURAL GAS/HYDROGEN	0.01000	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	EFFICIENT COMBUSTION	0.01000	BACT-PSD
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	NONE INDICATED	0.01000	LAER
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	CLEAN FUEL/NATURAL GAS ONLY	0.01000	BACT-PSD
REDBUD POWER PLT	TULSA, OK	8/15/2001	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	USE OF LOW ASH FUEL, EFFIECIENT COMBUSTION	0.01000	BACT-PSD
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	USE OF LOW ASH FUEL	0.01000	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01000	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01000	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP	0.01000	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	(2) NEW TURBINES, STACK 5 & 6	2,000	FIRING NAT GAS	0.01000	BACT-PSD
			(4) GAS FUELED TURBINES, STACK 1-4	2,200		0.01091	
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	TURBINE, COMBINED CYCLE (<75% LOAD)	1,480	GCP	0.01000	BACT-PSD
			TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480		0.01100	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000	FIRING NAT GAS	0.01000	BACT-PSD
			(4) TURBINES - ONLY CTG-1 TO 4	1,360		0.01324	
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	GCP, CLEAN FUEL	0.01008	BACT-PSD
RELIANT ENERGY- CHANNELVIEW COGENERATION	HOUSTON, TX	10/29/2001	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	0.01009	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN.	PHOENIX, AZ	12/2/2000	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	NONE INDICATED	0.01010	BACT-PSD
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000	FIRING NAT GAS	0.01015	BACT-PSD
			(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360		0.01346	
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	COMBINED CYCLE NATURAL GAS	2,362	GOOD COMBUSTION CONTROL	0.01016	BACT-OTHER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.01017	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP	0.01025	BACT-PSD
			(2) TURBINES AND DUCT BURNERS COMBINED	1,288		0.01258	
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	NONE INDICATED	0.01027	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	(2) GAS TURBINES	1,908	GCP GOOD DESIGN AND CLEAN BURNING NATURAL GAS	0.01034	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	5/16/2001	(2) GAS TURBINES (1-98A, 2-98A)	1,908	GCP GOOD DESIGN AND CLEAN BURNING NATURAL GAS	0.01034	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	TURBINE/HRSG W/O DUCT BURNER FIRING	672	NATURAL GAS AS FUEL	0.01042	BACT-OTHER
			TURBINE/HRSG W/ DUCT BURNER FIRING	672		0.01871	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	(4) TURBINES, COMBINED CYCLE MHI/SW @ 75% LOAD	1,400	GCP	0.01056	BACT-OTHER
			(4) TURBINES, COMBINED CYCLE MHI/SW	1,400		0.01342	
			(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		0.01523	
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	FIRING NAT GAS	0.01050	BACT-PSD
			(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360		0.01346	
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360	NATURAL GAS. GOOD COMBUSTION	0.01070	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945		0.01200	
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	(4) TURBINES, COMBINED CYCLE	1,372	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01071	BACT-PSD
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400	NONE INDICATED	0.01080	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	NONE INDICATED	0.01080	BACT
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000	NONE INDICATED	0.01080	BACT-OTHER

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FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376	NONE INDICATED	0.01090	BACT-PSD
			(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376		0.01693	
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	(2) MHI 501G COMBUSTION TURBINE	2,676	NONE INDICATED	0.01100	BACT
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	(3) SWPC 510G COMBUSTION TURBINES	2,880	CLEAN BURNING FUELS & EFFICIENT COMBUSTION	0.01100	BACT
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS	1,965	NAT GAS AS PRIMARY FUEL	0.01100	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE, GA	1/15/2002	(2) TURBINE, COMBINED CYCLE	1,336	GCP, LOW SULFUR FUEL	0.01100	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	(2) TURBINE, COMBINED CYCLE	2,699	NATURAL GAS FUEL	0.01100	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	0.01100	BACT-OTHER
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	(2) TURBINES, COMBINED CYCLE	1,280	COMBUSTION CONTROL	0.01100	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791	NONE INDICATED	0.01128	BACT-PSD
			(4) TURBINE, COMBINED CYCLE	1,491		0.01200	
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	(2) TURBINE, COMBINED CYCLE	2,737	LOW ASH FUEL AND GCP	0.01136	BACT-PSD
GREGORY POWER FACILITY	TEXAS	6/16/1999	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	FIRING NAT GAS	0.01149	BACT-PSD
			(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		0.01486	
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	(4) GAS TURBINES/DUCT BURNERS	2,876	USE OF CLEAN BURNING FUELS	0.01165	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	TURBINES AND DUCT BURNERS	2,480	LOW ASH FUEL (NATURAL GAS)	0.01170	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	NONE INDICATED	0.01178	BACT-PSD
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	(2) TURBINE, COMBINED CYCLE	2,132	NONE INDICATED	0.01190	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	(3) COMBINED CYCLE TURBINES	2,049	CLEAN BURNING FUEL & EFFICIENT COMBUSTION	0.01200	BACT
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	TURBINE, W/ DUCT BURNER	1,360	COMBUSTION OF NATURAL GAS ONLY	0.01200	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	GCP ALONG WITH USE OF NATURAL GAS	0.01200	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	GCP	0.01200	BACT-PSD
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL	0.01200	BACT-PSD
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	(2) TURBINES, COMBINED CYCLE	3,630	NATURAL GAS FUEL	0.01200	BACT-PSD
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	TURBINE, COMBINED CYCLE	2,493	CLEAN FUEL - NATURAL GAS	0.01200	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01200	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.01200	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	NONE INDICATED	0.01202	BACT-OTHER
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	0.01233	BACT-OTHER
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	NONE INDICATED	0.01238	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	(2) TURBINE, COMBINED CYCLE	2,000	NONE INDICATED	0.01244	LAER
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (SWH)	1,360	GCP/CLEAN FUEL	0.01250	BACT-PSD
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NG < 0.8 GR/100SCF	0.01250	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	(2) GAS TURBINES HRSG-1 & -2	1,440	PIPELINE QUALITY NAT GAS	0.01250	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	(4) TURBINES, COMBINED CYCLE	1,515	NONE INDICATED	0.01254	BACT-PSD
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.01276	BACT
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	0.01278	BACT-OTHER
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	TURBINE, COMBINED CYCLE	1,923	NONE INDICATED	0.01280	BACT-PSD
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	(2) TURBINES, COMBINED CYCLE	1,715	GCP AND DESIGN	0.01283	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	GCP AND USE OF NATURAL GAS	0.01286	BACT-PSD
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	(4) GAS TURBINES IN COMBINED CYCLE MODE, W/ DUCT BURNER	1,774	GCP, USING CLEAN NATURAL GAS	0.01297	BACT-PSD
			(4) COMBINED CYCLE GENERATION UNIT, W/O DUCT BURNER	1,464		0.01783	
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	0.01297	OTHER
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	(2) COMBINED CYCLE TURBINE	1,464	NATURAL GAS WITH LOW ASH CONTENT	0.01298	BACT-PSD
CPV Warren, LLC	FRONT ROYAL, VA	7/30/2004	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	LOW SULFUR GAS < 0.002%	0.01300	BACT
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	TURBINE COMBINED CYCLE UNIT	848	EFFICIENT COMBUSTION	0.01300	BACT-PSD
HOT SPRINGS POWER PROJECT	ARIZONA	11/9/2001	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	CLEAN FUELS	0.01300	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	COMBUSTION TURBINE	360	LOW ASH FUEL	0.01300	BACT-PSD
HENRY COUNTY POWER	VIRGINIA	11/21/2002	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	GOOD COMBUSTION DESIGN AND CLEAN FUEL	0.01300	BACT-PSD
			(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		0.01400	
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	(3) COMBUSTION TURBINE W/ AND W/O DUCT BURNER	2,181	NONE INDICATED	0.01300	NSPS
			(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		0.01540	
			(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		0.01730	
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	PORPER COMBUSTION	0.01302	BACT-PSD
PLANT NO. 2	LUBBOCK, TX	1/8/1999	(2) TURBINE/DUCT BURNER STGT1 & T2	336	FIRING NAT GAS	0.01310	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	TURBINE, COMBINED CYCLE	2,040	NONE INDICATED	0.01324	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION	0.01324	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	USE OF CLEAN BURNING FUELS	0.01324	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	NONE INDICATED	0.01332	BACT-PSD
			(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		0.01587	
FORNEY PLANT	HOUSTON, TX	3/6/2000	(6) TURBINES	1,358	GCP	0.01325	BACT-PSD
			(6) COMBINED TURBINE & DUCT BURNER	1,358		0.09526	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	GCP	0.01340	BACT-PSD
			(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		0.01735	
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NATURAL GAS FUEL USED	0.01352	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	PIPELINE QUALITY NATURAL GAS AND GCP	0.01360	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE, FL	12/14/1992	TURBINE,GAS	1,214	GOOD COMBUSTION PRACTICES	0.0136	BACT-PSD
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	GCP	0.01360	BACT-PSD
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	EXCLUSIVE USE OF NATURAL GAS	0.01361	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	NONE INDICATED	0.01397	BACT-PSD
			(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		0.02059	
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	0.01400	BACT-PSD
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	(4) TURBINES, COMBINED CYCLE	2,380	NONE INDICATED	0.01400	BACT-PSD
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.01400	BACT-PSD
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	(3) TURBINE, COMBINED CYCLE	1,467	NONE INDICATED	0.01400	BACT-OTHER
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944	NONE INDICATED	0.01400	BACT-PSD
			(3) TURBINES, COMBINED CYCLE	1,944		0.01700	
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	(3) TURBINE/HRSGS CTG1-3	2,000	GCP & FIRING NON-ASH CONTAINING GASEOUS FUELS	0.01415	BACT-PSD
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (GE)	1,360	GCP/CLEAN FUEL	0.01434	BACT-PSD
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	(2) TURBINE, COMBINED CYCLE	1,480	GCP/CLEAN FUEL	0.01459	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	FIRING NATURAL GAS	0.01467	BACT-PSD
			(4) GAS TURBINES TURBINE ONLY FIRING	1,360		0.01493	
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	(2) CTG-HRSG STACKS STACK1 & 2	1,440	FIRING PIPELINE-QUALITY NAT GAS	0.01476	BACT-PSD
NYPA Poletti Power Project	ASTORIA, NY	10/1/2002	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.01500	BACT
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	(2) TURBINES, COMBINED CYCLE	1,701	CLEAN FUEL AND EFFICIENT COMBUSTION	0.01500	BACT-OTHER
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191	LOW SULFUR FUEL	0.01500	BACT-PSD
			(3) TURBINE, COMBINED CYCLE	1,798		0.01600	
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	(3) COMBINED CYCLE TURBINE W/O DUCT BURNER	2,964	NONE INDICATED	0.01500	BACT-PSD
			(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202		0.01700	
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	GCP & FIRING NON-ASH CONTAINING GASEOUS FUELS	0.01515	BACT-PSD

Appendix E: Table E-4
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	GCP AND THE USE OF NATURAL GAS	0.01517	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464	FIRING NATURAL GAS IN THE TURBINES AND DUCT BURNERS	0.01530	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GENERATING STA	BURNSVILLE, MN	11/17/2000	COMBUSTION TURBINE WITH HRSG	1,917	USE OF NATURAL GAS AS THE EXCLUSIVE FUEL	0.01534	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE INDICATED	0.01544	BACT-PSD
			(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		0.01838	
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	GCP AND FIRING ONLY GASEOUS FUELS	0.01547	BACT-PSD
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	(2) TURBINE, COMBINED CYCLE	2,240	NONE INDICATED	0.01554	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	CLEAN FUEL AND GCP	0.01570	BACT-PSD
BASF CORPORATION	GEISMAR, LA	12/30/1997	(2) TURBINE, COGEN UNIT GE FRAME 6	339	GOOD DESIGN & OPERATING PRACTICES USE GASEOUS FUELS	0.01592	BACT-PSD
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	NONE INDICATED	0.01600	OTHER
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	COGEN STACK TURBINE ONLY	310	FIRING NAT GAS	0.01615	BACT-PSD
			COGEN STACK COMBINED GT/HRSG&DB 1180	310		0.02590	
PPG INDUSTRIES	LAKE CHARLES, LA	12/2/1999	COGENERATION UNIT 5 AND 6 (EACH)	1,320	GCP, CLEAN BURNING FUEL	0.01621	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	(2) COGENERATION UNITS COMBINED CYCLE	320	GCP	0.01625	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	CLEAN FUELS	0.01660	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STA	KANSAS CITY, MO	8/19/1999	(2) TURBINE, COMBINED	1,360	GCP	0.01662	BACT-OTHER
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	(2) TURBINE, COMBINED CYCLE	640	NONE INDICATED	0.01688	BACT-OTHER
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	LNB, PROPER OPERATING INSTRUCTIONS & USE OF NATL GAS	0.01691	BACT-PSD
			(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		0.01919	
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	(4) COMBINED CYCLE GAS TURBINE STACK1-4	1,400	FIRING NAT GAS	0.01714	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	(2) TURBINE, COMBINED CYCLE	1,376	USE OF NATURAL GAS & STATE OF THE ART COMBUSTION	0.01744	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	FIRING PIPELINE QUALITY NAT GAS	0.01781	NSPS
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	LOW SULFUR FUELS	0.01820	OTHER
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	GCP WITH USE OF NATURAL GAS	0.01832	BACT-PSD
			TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166		0.01910	
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP, USE OF GASEOUS FUELS CONTAINING NO ASH	0.01882	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	(2) TURBINES, COMBINED CYCLE	1,795	NONE INDICATED	0.01894	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	GE COMBUSTION TURBINE & DUCT BURNERS	1,705	LOW SULFUR FUEL AND EFFICIENT COMBUSTION	0.01900	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	(3) TURBINE, COMBINED CYCLE	1,844	USE OF ONLY CLEAN-BURNING LOW-SULFUR FUELS AND GCP	0.01900	BACT-PSD
			(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844		0.02100	
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	USE OF NATURAL GAS AS FUEL	0.01905	BACT-PSD
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	FIRING NAT GAS	0.01918	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN, GA	4/3/1996	COMBUSTION TURBINE (2), NATURAL GAS	928	CLEAN FUEL	0.0194	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	(3) TURBINE & DUCT BURNER	1,360	EFFICIENT COMBUSTION	0.02000	BACT-PSD
ROQUETTE AMERICA	KEOKUK, IA	1/31/2003	TURBINE, COMBINED CYCLE	587	GCP, NATURAL GAS ONLY	0.02000	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	(2) GAS TURBINE COMBINED CYCLE	2,096	NONE INDICATED	0.02000	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	TURBINE, NG, 3 AT 170MW EA W/ DUCTBURNER	1,360	EFFICIENT COMBUSTION	0.0200	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	LOW ASH FUEL AND GCP	0.02039	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	FIRING PIPELINE NAT GAS	0.02043	BACT-PSD
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	(1) COMBINED CYCLE COMBUSTION TURBINE, W/ AND W/O DB	1,779	CLEAN FUELS	0.02100	OTHER
TPS - DELL, LLC	DELL, AR	8/8/2000	(2) TURBINE	2,560	GCP	0.02100	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	(2) TURBINES, COMBINED CYCLE	1,360	GCP, CLEAN FUEL	0.02154	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	FIRING PIPELINE NAT GAS	0.02163	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	NONE INDICATED	0.02222	BACT-OTHER
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	(2) TURBINE, COMBINED CYCLE	1,384	COMBUSTION CONTROL	0.02262	BACT-PSD
CONTINENTAL ENERGY SVCS, INC., SILVER BOW GEN	BUTTE, MT	6/7/2002	(4) COMBINED CYCLE CT	1,400	NONE INDICATED	0.02314	OTHER
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING PIPELINE-QUALITY NAT GAS	0.02354	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	ARIZONA	4/1/2002	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION CONTROL CLEAN FUEL	0.02368	BACT-PSD
FULTON COGEN PLANT	FULTON, NY	9/15/1994	STACK EMISSIONS (TURBINE & DUCT BURNER)	610	NONE INDICATED	0.02400	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP	VA	5/4/1990	TURBINE, COMBUSTION	1,261	FUEL SPEC: CLEAN BURNING FUEL, NAT GAS & DIST. #2 OIL	0.0262	OTHER
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	COMBUSTION TURBINE W/ DUCT BURNER	623	LNB	0.02700	BACT-PSD
			COMBUSTION TURBINE W/O DUCT BURNER	457		0.03300	
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(2) COMBUSTION GS TURBINE GENERATORS STACK7&8	1,400	FIRING NAT GAS	0.02714	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	(4) HRSG/TURBINES 001,002,003,004	1,400	GOOD COMBUSTION CONTROLS	0.02757	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(6) COMBUSTION GS TURBINE GENERATORS STACK	1,400	FIRING NAT GAS	0.02907	BACT-PSD
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	(4) GAS TURBINES & WHB - COMBINED	114	FIRING NAT GAS	0.03345	BACT-OTHER
GEISMAR PLANT	GEISMAR, LA	2/26/2002	(2) COGENERATION UNITS W/ AND W/O DB	320	USE OF CLEAN NATURAL GAS WITH GCP	0.03375	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP & FIRING ONLY GASEOUS FUELS CONTAINING NO ASH	0.03582	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	(3) TURBINE, COMBINED CYCLE AND DB, W/ AND W/O POWER AUG.	2,300	STATE OF THE ART COMBUSTION & NATURAL GAS	0.03616	BACT-PSD
			(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650		0.05041	
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	(4) TURBINE, COMBINED CYCLE	477	GOOD COMBUSTION	0.04406	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	0.06000	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	0.06000	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	0.06000	BACT-OTHER
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	0.06000	BACT-PSD
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	USE OF PIPELINE QUALITY NATURAL GAS	0.14000	BACT-OTHER

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-5
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CPV WARREN	WARREN, VA	1/14/2008	NO	(2) GE 207FA NG COMBINED-CYCLE TURBINES, W/ HRSG & DB	1,944	CEMS, GOOD COMB. PRAC. 2 STAGE LEAN PREMIX	0.0002	NA
				(2) GE MODEL 7FA NATURAL GAS COMBINED-CYCLE	1,717	GOOD COMBUSTION PRACTICES	0.0003	NA
				(2) SIEMENS MODEL SGT6-5000	2,204	GOOD COMBUSTION PRACTICES.	0.0003	NA
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	PIPELINE QUALITY NAT GAS AND GCP	0.0005	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	NONE INDICATED	0.0005	BACT-OTHER
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	3 COMBINED-CYCLE COMBUSTION TURBINES W/ DB	1,844	USE OF VERY LOW-SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
				TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844	LOW SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	SULFUR CONTENT IN GAS	0.0006	OTHER
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,844	USE OF VERY LOW-SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.0006	BACT
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	USE OF NATURAL GAS ONLY	0.0006	OTHER
PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	COMBUSTION OF LOW SULFUR FUELS, NO FUEL > 0.5% S	0.0006	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUEL - < 0.05% S BY WT	0.0006	BACT-PSD
CAROLINA POWER & LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	NONE INDICATED	0.0006	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	NONE INDICATED	0.0006	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	NONE INDICATED	0.0006	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	LOW SULFUR FUELS	0.0006	BACT-OTHER
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	FUEL SULFUR LIMITED TO < 8 PPMV FOR NG	0.0007	BACT
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	FIRING SWEET PIPELINE-QUALITY NAT GAS	0.0007	BACT-OTHER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP, LOW SULFUR FUEL	0.0008	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	0.0008	BACT-PSD
				(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		0.0011	
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/O DUCT BURNER FIRING	672	NATURAL GAS	0.0008	NSPS
				TURBINE/HRSG W/ DUCT BURNER FIRING	672		0.0012	
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470	GCP & SULFUR IN NG LIMITED TO 0.3 GR/100 DSCF	0.0008	BACT-PSD
				(2) TURBINE, COMBINED CYCLE	1,827		0.0010	
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, NO DUCT BURNER FIRING	1,937	NONE INDICATED	0.0009	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		0.0011	
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	NONE INDICATED	0.0009	BACT-PSD
				COMBUSTION TURBINE, W/O DUCT BURNER	908		0.0400	
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 6ISTK001-003	1,464	FIRING NAT GAS	0.0010	BACT-OTHER
CAITHNESS BELLPORT, LLC	SUFFOLK, NY	5/10/2006	NO	COMBINED CYCLE WITH DUCT FIRING UP TO 494 MMBTU/H	2,221	LOW SULFUR FUEL	0.0011	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.0011	BACT-PSD
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	PIPELINE QUALITY NATURAL GAS	0.0011	BACT-OTHER
TransGas Energy Systems	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.0011	BACT
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	MAX SULFUR CONTENT OF NG </= 0.3 GRAINS/100 SCF	0.0012	BACT-PSD
				(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		0.0013	
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	FIRING LOW S NAT GAS	0.0014	BACT-PSD
				(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360		0.0018	
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	BURN ONLY PIPELINE QUALITY NATURAL GAS	0.0014	BACT-OTHER
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES, ALL LOADS	2,049	LOW SULFUR FUEL < 0.5 GR/100SCF	0.0014	BACT
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000	FIRING NAT GAS W/ SULFUR CONTENT OF 5 GR S/100 DSCF	0.0014	BACT-PSD
				(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360		0.0018	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000	FIRING LOW S NAT GAS	0.0014	BACT-PSD
				(4) TURBINES - ONLY CTG-1 TO 4	1,360		0.0018	
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	2 GRAINS S PER 100 SCF NATURAL GAS	0.0014	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	LOW-SULFUR NATURAL GAS </= 4 PPM S IN NATURAL GAS	0.0015	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	0.0015	BACT-OTHER
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUEL	0.0015	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0015	BACT-PSD
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES	1,611	LOW SULFUR NATURAL GAS	0.0016	LAER
CPV Warren, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	LOW SULFUR GAS < 0.002%	0.0016	BACT
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	USE OF CLEAN FUEL/NATURAL GAS	0.0017	BACT-PSD
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	LOW SULFUR FUELS	0.0017	OTHER
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	LOW S FUEL	0.0017	BACT-OTHER
				(2)GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		0.0020	
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	LOW - SULFUR FUEL: NATURAL GAS	0.0017	BACT-OTHER
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	NONE INDICATED	0.0017	OTHER
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW SULFUR NATURAL GAS	0.0018	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NONE INDICATED	0.0020	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NONE INDICATED	0.0020	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	LOW SULFUR FUEL	0.0020	BACT-PSD
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	LOW SULFUR FUEL	0.0020	OTHER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.0020	BACT-OTHER
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(2) NEW TURBINES, STACK 5 & 6	2,000	PIPELINE-QUALITY NAT GAS 0.8 GR S/100 DSCF	0.0020	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	USE OF PIPELINE QUALITY LOW-SULFUR NATURAL GAS	0.0020	BACT-PSD
				(4) GAS TURBINES TURBINE ONLY FIRING	1,360		0.0021	
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	0.0020	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	LOW SULFUR FUEL; S CONTENT OF FUEL IS 0.75 GR/100 SCF	0.0021	BACT-PSD
LAKE ROAD GENERATING CO., L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	LOW SULFUR FUEL < 0.05% S	0.0022	BACT
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS	1,965	NAT GAS AS PRIMARY FUEL 0.8 GR/100 SCF	0.0022	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	LOW SULFUR FUEL NG. NATURAL GAS < 0.8 GR/100SCF	0.0022	BACT-OTHER
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	CLEAN FUEL - NG WITH .8 GRAINS SULFUR/100 SCF	0.0022	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	0.0022	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	SULFUR CONTENT OF FUEL.	0.0022	BACT-PSD
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.0023	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		0.0026	
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) GAS FUELED TURBINES, STACK 1-4	2,200	LOW S FUEL	0.0023	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION TECHNOLOGY	0.0023	BACT-PSD
SITHE - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	NONE INDICATED	0.0023	BACT
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	PIPELINE QUALITY NATURAL GAS < 0.75 grains/100 SCF	0.0023	BACT-OTHER
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	0.0023	BACT-PSD
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	?	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL	0.0023	BACT-PSD
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYCLE	3,630	NATURAL GAS FUEL	0.0023	BACT-PSD

Appendix E: Table E-5
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	LOW SULFUR FUELS	0.0023	BACT-PSD
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	USE OF PIPELINE QUALITY NATURAL GAS ONLY	0.0025	BACT-OTHER
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791	LOW S NAT GAS: < .007 %S BY WT (2 GR/100 SCF) GCP	0.0025	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE W/ & W/O DB (ALL LOADS)	2,181	NATURAL GAS AS FUEL WITH <= 0.8% SULFUR BY WEIGHT	0.0025	NSPS
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	BURN NATURAL GAS	0.0026	BACT-OTHER
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	FIRING PIPELINE NAT GAS < 0.5 GRAINS/100 DSCF	0.0026	BACT-OTHER
LOWER MOUNT BETHEL ENERGY, LLC	PENNSYLVANIA	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	LOW SULFUR FUEL	0.0027	LAER
SPRINGDALE TOWNSHIP STATION	GREENSBURG	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP, LOW SULFUR FUEL	0.0027	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	LOW SULFUR FUEL	0.0028	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		0.0030	
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	0.0028	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	LOW S NAT GAS: 0.007 % S BY WT (2 GR/100 SCF) GCP	0.0028	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	PIPELINE QUALITY NAT GAS	0.0028	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	GCP (LOW S FUEL - 0.8 GR/100 DSCF)	0.0029	LAER
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	LOW S CONTENT IN FUEL -.8 GRAINS PER 100 CU FT	0.0029	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	LOW S FUEL: < 2 GR/100 CF, 7 DAY AVG 1.1 GR/100 CF, 12 MO AVG	0.0030	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	VERY LOW SO2 EMISSION RATE-LOW SULFUR FUEL	0.0030	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	LOW S NATURAL GAS ONLY (LESS THAN 0.8% BY WEIGHT)	0.0031	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	NAT GAS W/ MAX S CONTENT OF 1 GR/100 SCF	0.0031	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	LOW SULFUR FUEL, 1 GR/100 SCF	0.0031	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707		0.0032	
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(2) COMBUSTION GS TURBINE GENERATORS STACK7&8	1,400	NAT GAS CONTAINING NOT MORE THAN 0.8 GR S/100 DSCF	0.0033	BACT-PSD
LAKELAND C.D. - MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	CLEAN FUELS, GOOD COMBUSTION	0.0033	OTHER
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	USE OF LOW SULFUR NATURAL GAS AS SOLE FUEL	0.0034	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	?	(4) COMBINED CYCLE GAS TURBINE STACK1-4	1,400	LOW S FUEL	0.0036	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUELS.	0.0036	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0036	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	0.0036	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	FUEL SULFUR CONTENT	0.0038	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	0.0040	BACT-OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE W/ AND W/O DUCT BURNER	3,202	NONE INDICATED	0.0040	OTHER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(6) COMBUSTION GS TURBINE GENERATORS STACK	1,400	NAT GAS CONTAINING NOT MORE THAN 0.8 GR S/100 DSCF	0.0041	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	0.0042	BACT-OTHER
KLEEN ENERGY SYSTEMS, LLC (DRAFT)	MIDDLESEX, CT	2/25/2008	NO	(2) SIEMENS SGT6-5000F TURBINES (HRSG & NG DUCT BURNER)	1,071	NONE INDICATED	0.0048	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	FIRING PIPELINE NAT GAS	0.0048	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	2,325	LOW SULFUR FUELS	0.0049	BACT-PSD
				TURBINE, COMBINED CYCLE	1,973		0.0058	
HAYWOOD ENERGY CENTER, LLC	TAMPA	2/1/2002	?	TURBINE, COMBINED CYCLE W/O DUCT FIRING	1,990	LOW SULFUR FUEL (<2.0 GR SULFUR PER 100 SCF OF NATURAL GAS)	0.0049	BACT-PSD
				TURBINE, COMBINED CYCLE W/ DUCT FIRING	1,990		0.0059	
CRESENT CITY POWER, LLC	ORLEANS, LA	6/6/2005	YES	600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	2,006	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	0.0050	BACT-PSD
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	LOW SULFUR FUEL - PIPELINE QUALITY NATURAL GAS	0.0050	BACT-PSD
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	PIPELINE QUALITY NATURAL GAS	0.0050	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	FIRING NAT GAS < 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0051	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	CLEAN FUEL - NATURAL GAS	0.0054	BACT-PSD
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.0055	BACT
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE	2,200	SWEET NAT GAS W/ MAX S CONTENT 0.8 GR/100 SCF	0.0055	BACT-PSD
PROGRESS ENERGY FLORIDA (PEF)	PINELLAS, FL	1/26/2007	NO	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	493	NONE INDICATED	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT COMPANY	WEST PALM BEACH, FL	1/10/2007	NO	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	389	LOW SULFUR FUELS	0.0056	BACT-PSD
PROGRESS ENERGY	POLK, FL	6/8/2005	YES	COMBINED CYCLE POWER PLANT (4TH POWER BLOCK) TOTAL GEN CAPACITY OF FACILITY 2090 MW.	4,240	CLEAN FUELS	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT	DADE, FL	2/8/2005	YES	4 GE MODEL FA GAS TURBINES (170 MW EACH), 4 HRSGS, 1 STEAM TURBINE-ELECTRICAL GENERATOR (470 MW)	1,360	NATURAL GAS AND RESTRICTING THE AMOUNTS OF ULTRA LOW SULFUR DISTILLATE OIL.	0.0056	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	PIPELINE-QUALITY, SWEET NAT GAS 2.0 GR S/100 DSCF	0.0056	NSPS
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	LOW SULFUR FUEL (NATURAL GAS)	0.0056	BACT-PSD
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	GCP BASED ON SULFUR CONTENT (2 GR/DSCF)	0.0056	BACT-OTHER
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW SULFUR FUELS	0.0057	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON, AL	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL.	0.0057	BACT-PSD
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON/OFF	1,440	BURNING NATURAL GAS	0.0057	BACT-PSD
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/ & W/O DB	1,440	NONE INDICATED	0.0057	BACT-PSD
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945	GOOD COMBUSTION. NATURAL GAS ONLY	0.0057	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360		0.0083	
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	CLEAN FUELS. < 0.0065 % S GAS COMBUSTION CONTROLS	0.0059	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	FUEL SPECIFICATION: LOW SULFUR FUELS	0.0060	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,944	GCP	0.0060	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	0.0060	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	0.0060	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	USE OF NATURAL GAS	0.0060	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	PIPELINE-QUALITY NATURAL GAS (VERY LOW SULFUR FUEL) MAXIMUM 0.8 % S BY WT.	0.0060	BACT-PSD
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166	CLEAN FUEL	0.0060	BACT-PSD
				TURBINE, COMBINED CYCLE W DUCT BURNER	2,516		0.0062	
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	LOW SULFUR FUELS AND GOOD COMBUSTION DESIGN	0.0060	BACT-PSD
				(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		0.0135	
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	FIRING NAT GAS, 1.25 GR/100SCF	0.0061	BACT-OTHER
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	LOW SULFUR FUEL (2) GR/100 SCF	0.0063	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	NONE INDICATED	0.0067	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	AMINE SCRUBBER	0.0069	LAER
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	PIPELINE QUALITY NAT GAS < 2.5 GR S/100 DSCF SHORT-TERM, AND 0.2 GR S/100 DSCF 12 MO ROLLING AV	0.0069	NSPS
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	PIPELINE QUALITY NAT GAS < 2.0 GR S/100 DSCF	0.0069	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	LOW S FUELS AND EFFICIENT COMBUSTION TECHNIQUES		BACT
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	NATURAL GAS ONLY	0.0070	BACT-PSD

Appendix E: Table E-5
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE W/ AND W/O DUCT BURNER	623	LNB	0.0070	BACT-PSD
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	LOW SULFUR FUEL	0.0070	BACT-OTHER
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191		0.0080	
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	0.0071	BACT-OTHER
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE, W/ & W/O DB	2,423	CLEAN FUELS	0.0071	OTHER
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	NATURAL GAS A FUEL	0.0071	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	LOW SULFUR FUEL	0.0071	BACT-PSD
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	NAT GAS W/ S CONTENT OF 0.2 GR S/100 DSCF ANNUALLY AND 2.5 GR S/100 DSCF HOURLY	0.0072	BACT-OTHER
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	LOW SULFUR FUEL	0.0072	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	0.0073	BACT-OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	FIRING NAT GAS	0.0076	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	PIPELINE QUALITY NATURAL GAS OF NGT 0.5 GR/100 CF	0.0079	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376	LOW SULFUR FUEL: MAXIMUM S CONTENT OF NATURAL GAS < 2 GRAINS/100 SCF	0.0080	BACT-PSD
				(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376		0.0105	
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	LOW S NATURAL GAS 2 GR/100 SCF	0.0082	BACT-PSD
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		0.0107	
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	LOW SULFUR FUELS AND GCP	0.0085	BACT-PSD
CHAMPION INTL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	0.0086	BACT-OTHER
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	PIPELINE NAT GAS S CONTENT < 2 GR/100 SCF OR 65 PPMW	0.0101	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360	NONE INDICATED	0.0103	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(2) TURBINE/HRSG NO.1,2	3,168	PIPELINE NG; SHORT-TERM MAX 5 GR S/100CF; < 2 GR S/100 CF	0.0106	BACT-PSD
GREGORY POWER FACILITY	COSTA MESA, TX	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	PIPELINE QUALITY NAT GAS, CONTAINING < 3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0106	NSPS
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		0.0133	
SOUTHWEST ELECTRIC POWER COMPANY	SHREVEPORT, LA	3/20/2008	YES	(2) COMBINED CYCLE GAS TURBINES	1,055	USE LOW-SULFUR PIPELINE-QUALITY NATURAL GAS	0.0114	BACT-PSD
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	NAT GAS, < 3 GR S/100 DSCF (SHORT-TERM)& 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0119	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	NONE INDICATED	0.0124	BACT-OTHER
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.0129	NSPS
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	PIPELINE-QUALITY NAT GAS CONTAINING < 0.2 GR S/100 DSCF ON AN ANNUAL AV AND 2.5 GR S/100 DSCF ON A MAX H BASIS	0.0131	BACT-OTHER
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION	1,735	GCP AND LOW SULFUR FUEL (0.8 % BY WT SULFUR)	0.0131	NSPS
				(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735		6.0000	
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	LOW S FUEL	0.0134	BACT-OTHER
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	PIPELINE QUALITY NATURAL GAS	0.0140	BACT-PSD
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	GCP & FIRING LOW S-CONTENT FUELS	0.0141	BACT-OTHER
PLAQUEMINE, IBERVILLE PARISH	LOUISIANA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	LOW SULFUR FUELS MAX S CONTENT OF 5 GR/100 SCF	0.0142	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	LOW SULFUR FUEL	0.0146	OTHER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.0152	BACT-PSD
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	LOW SULFUR FUEL	0.0156	BACT-PSD
RELIANT ENERGY- CHANNELVIEW COGEN	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	0.0165	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	USE OF PIPELINE QUALITY NATURAL GAS., S<0.5%	0.0173	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	GCP, LOW SULFUR FUEL	0.0176	BACT-OTHER
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	GC,P FIRE ONLY NAT GAS W/ S CONTENT < 5.0 GR/100 DSCF	0.0190	BACT-PSD
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	FIRING LOW SULFUR PIPELINE NAT GAS	0.0194	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		0.0487	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	FIRING NAT GAS	0.0208	BACT-OTHER
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		0.0250	
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP. LOW S FUEL: < 5.0 GR S/100 DSCF (SHORT-TERM) + 1.0 GR TOTAL S/100 DSCF (ANNUAL AVG)	0.0211	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		0.0244	
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING LOW-S FUELS	0.0222	BACT-OTHER
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP, LOW SULFUR FUELS (NAT GAS W/< 5 GR S/100 DSCF ON H AVER & 0.25 GR S/100 DSCF FOR AN ANN. AVER)	0.0224	BACT-OTHER
TENASKA FRONTIER GENERATION STATION	TEXAS	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464	FIRING NATURAL GAS IN THE TURBINES AND DUCT BURNERS	0.0229	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	LOW SULFUR NATURAL GAS (LESS THAN 2 G/DSCF)	0.0231	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	LOW SULFUR FUEL (<5 GR/100 SCF) AND PROPER COMBUSTION	0.0232	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	PIPELINE QUALITY NAT GAS	0.0258	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	USE OF SOLVENT BASED ABSORPTION TECHNOLOGY WITH TAIL GAS RECIRCULATION PRIOR TO COMBUSTION	0.0284	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	FUEL SPEC: 0.1 % SULFUR IN FUEL	0.0314	BACT-OTHER
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	PIPELINE QUALITY NAT GAS WITH NO > 1.0 GR S/100 DSCF	0.0392	NSPS
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	FIRING PIPELINE QUALITY NAT GAS	0.0481	BACT-OTHER
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		0.0757	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE I: TURBINES E-1+E-2 W/O HRSG	720	NONE INDICATED	0.0411	NSPS
				(2) CASE II: TURBINES E-1+E-2 W/ HRSG	720		0.0438	
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP & LOW S FUEL GASES < 0.5 GRAINS/DSCF	0.0452	BACT-OTHER
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	NONE INDICATED	0.0460	SIP
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	PRIMARY FUEL GAS OR PIPELINE QUALITY SWEET NATURAL GAS WITH NO > 5 GR/100	0.0528	NSPS
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	S & H2S LIMITATIONS IN FUEL SPECIFIED AT THE FACILITY LEVEL	0.0796	BACT-OTHER
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	USE OF PIPELINE QUALITY GAS AND GCP	0.0842	BACT-PSD
INEOS USA LLC	BRAZORIA, TX	8/29/2006	YES	COGENERATION TRAIN 2 AND 3 (TURBINE & DB)	140	TURBINES & DB WILL FIRE NATL GAS & COMPLEX GAS W/ S CONTENT < 5 GR/100 SCF ON AN HOURLY BASIS	0.0904	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	NONE INDICATED	0.2000	BACT-OTHER
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	S CONTENT OF FUEL LESS THAN OR EQUAL TO 0.2% BY WEIGHT	0.4028	BACT-PSD
GULF STATES UTILITIES COMPANY - LOUISIANA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	MAX H2S CONC OF 33.53 PPM @ 15% O2 IN FLUE GAS (DRY BASIS)	1.0212	OTHER
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
DUKE ENERGY-JACKSON FACILITY	ARKANSAS	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	CLEAN FUEL	--	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	FUEL SPEC: NATURAL GAS FUEL; COMBUSTION OF CLEAN FUELS	--	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,696	NATURAL GAS	--	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	NATURAL GAS ONLY	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	PERMIT LIMIT IS LOW SULFUR FUELS	--	

Appendix E: Table E-5
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	LOW SULFUR FUELS: GAS < .0065 % SULFUR;NO EMISSION LIMITS	--	BACT-PSD
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	NATURAL GAS 1 GR/100 SCF OF GAS	--	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA, FL	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	CLEAN FUELS	--	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	CLEAN FUELS SULFUR FUEL LIMIT	--	BACT-OTHER
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS - < .0065 % S	--	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS, FUEL SULFUR LIMIT: .0065% S	--	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE	1,600	LOW SULFUR FUELS	--	BACT-PSD
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYCLE	1,600	LOW SULFUR FUELS	--	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	NAT GAS W/ MAX OF 2.0 GRAINS OF SULFUR PER 100 SCF	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	PERMIT LIMIT IS LOW SULFUR FUELS	--	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	?	(2) TURBINE, COMBINED CYCLE	1,376	PIPELINE QUALITY NAT GAS W/ 0.2 GR S/100 CF	--	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(11) TURBINE, COMBINED CYCLE	984	NAT GAS W/S CONTENT OF 0.2 GRAINS/100 CF OF GAS	--	BACT-PSD
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	MAX S CONTENT 0.004 GR/DSCF USING 12-MONTH ROLLING AVG	--	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	LOW SULFUR FUEL: < 0.8 % S BY WT	--	NSPS
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	FUEL NOT TO EXCEED 0.8 % S BY WT	--	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	FUEL SPEC: LNG/LPG AS PRIMARY FUEL	--	BACT-PSD
CHAMBERS ENERGY L.P./AMERICAN NATIONAL POWER	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	LOW SULFUR FUEL	--	BACT-PSD
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	NG W/ S CONT <5.0 GRAINS/100 DSCF (HRLY), <0.2 GRAINS/100 DSCF (ANNUAL), GCP	--	BACT-OTHER

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-6
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)
NORTON ENERGY STORAGE, LLC	HOUSTON	5/23/2002	YES	(9) COMBUSTION TURBINES COMB CYCLE W/O DB	2,400	NONE LISTED	0.00008
				(9) COMBUSTION TURBINE COMB CYCLE W/ DB	2,400	NONE LISTED	0.00011
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 1	1,717	GOOD COMBUSTION PRACTICES	0.00010
			NO	ELECTRIC GENERATION - SCENARIO 2	1,944	GOOD COMBUSTION PRACTICES	0.00020
			NO	ELECTRIC GENERATION SECNARIO 3	2,204	GOOD COMBUSTION PRACTICES	0.00010
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.00010
DRESDEN ENERGY LLC	RICHMOND	10/16/2001	YES	(2) COMBUSTION TURBINE W/ & W/O DB	1,374	NONE LISTED	0.00015
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.00018
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.00018
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	?	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.00020
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NATURAL GAS COMBUSTION	0.00020
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360	FIRING LOW-S NATURAL GAS	0.00020
				(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	NONE INDICATED	0.00015
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW SULFUR NATURAL GAS FUEL	0.00021
PANDA CULLODEN GENERATING STATION	CULLODEN	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.00026
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.00030
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	NONE LISTED	0.00030
SPRINGDALE TOWNSHIP STATION	GREENSBURG	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GOOD COMBUSTION PRACTICES, LOW SULFUR FUEL	0.00033
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	LOW SULFUR FUEL < 0.5 GR/100SCF	0.00033
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE LISTED	0.00035
				(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360	NONE LISTED	0.00041
LIMA ENERGY COMPANY	CINCINNATI	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	NONE LISTED	0.00039
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE	2,221	LOW SULFUR FUEL	0.00040
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY,NV	8/16/2005	?	TURBINE, CC COMBUSTION #1 WITH HRSG & DB	2,448	BEST COMBUSTION PRACTICES	0.00041
WEATHERFORD ELECTRIC GENERATION FACILITY	ATLANTA	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	PIPELINE-QUALITY NAT GAS	0.00046
JACKSON COUNTY POWER, LLC	CHARLOTTE	12/27/2001	YES	(4) COMBUSTION TURBINES W/ DUCT BURNER	2,440	NONE LISTED	0.00048
CPV WARREN LLC	WARREN,VA	7/30/2004	?	TURBINE, COMBINED CYCLE (2)	1,717	MAX. 0.002% BY WT MAX S CONTENT	0.00050
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	LOW SULFUR FUEL: < 2 GR/100 CF 7 DAY AVG 1.1 GR/100 CF 12 MO AVG	0.00062
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION PRACTICES CLEAN BURNING LOW SULFUR FUELS	0.00066
DUKE ENERGY DALE, LLC	HOUSTON	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL	0.00070
DUKE ENERGY AUTAUGA, LLC	HOUSTON	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	NATURAL GAS AS EXCLUSIVE FUEL	0.00070
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	EXCLUSIVE USE OF NATURAL GAS	0.00073
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	NONE LISTED	0.00078
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	LOW SULFUR FUEL -- NATURAL GAS ONLY	0.00080
ENNIS TRACTEBEL POWER	ENNIS	1/31/2002	NO	COMBUSTION TURBINE W/HRSG	2,800	NONE INDICATED	0.00085
ARSENAL HILL POWER PLANT	CADDO,LA	3/20/2008	NO	TWO COMBINED CYCLE GAS TURBINES	2,110	USE OF PIPELINE QUALITY NAT GAS AND PROPER SCR DESIGN	0.00088
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002, 003 & 004	1,400	FIRING PIPELINE QUALITY NATURAL GAS	0.00093
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.00100
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	TURBINE/HRSG NO.1, 2 & 3	3,168	NAT GAS	0.00104
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	TURBINE/HRSG (CG-2) & (CG-3)	1,280	PROPER COMBUSTION CONTROL & LOW S FUELS	0.00106
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COMB. TURBINES W/HRSG - NG CC	1,568	NONE LISTED	0.00108
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW-SULFUR FUELS	0.00109
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	INHERENTLY LIMITED BY LOW SULFUR IN FUEL	0.00110
BARTON SHOALS ENERGY	ENGLEWOOD	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	NATURAL GAS ONLY	0.00110
EL PASO MERCHANT ENERGY CO.	HOUSTON	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	USE OF LOW SULFUR FUEL	0.00111
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	NATURAL GAS < 0.0065 %S	0.00118
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	NONE INDICATED	0.00118
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	GOOD COMBUSTION PRACTICES	0.00120
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376	NONE LISTED	0.00122
					1,376	NONE LISTED	0.00160
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	NONE LISTED	0.00125
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360	NONE LISTED	0.00162
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE W/ DB, POWER AUG.	2,200	USE OF NATURAL GAS. LOW SULFUR FUEL	0.00128
SATSOP COMBUSTION TURBINE PROJECT"		1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NONE LISTED	0.00130
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE W/ & W/O DB	1,440	NONE LISTED	0.00130
MANTUA CREEK GENERATING FACILITY		6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181	NONE	0.00138

Appendix E: Table E-6
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)
				(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181	NONE	0.00156
				(3) COMBUSTION TURBINE W/O DB 75%LOAD	1,636	NONE	0.00150
				(3) COMBUSTION TURBINE W/O DB 60% LOAD	1,309	NONE	0.00160
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	THE USE OF NATURAL GAS ONLY	0.00139
PANDA-BRANDYWINE	MARYLAND	6/17/1994	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE LISTED	0.00151
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.00155
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.00158
TENASKA TALLADEGA GENERATING STATION	OMAHA	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	PIPELINE QUALITY NATURAL GAS	0.00170
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.00173
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	USE OF LOW SULFUR FUEL	0.00186
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	USE OF PIPELINE QUALITY GAS	0.00187
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	?	(1) COMBINED CYCLE COMBUSTION TURBINE W & W/O DB	1,779	CLEAN FUELS	0.00220
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES TURBINE ONLY FIRING	1,360	USE OF PIPELINE QUALITY LOW-SULFUR NATURAL GAS	0.00206
				(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	USE OF PIPELINE QUALITY LOW-SULFUR CONTENT NATURAL GAS	0.00023
HAYWOOD ENERGY CENTER, LLC	TAMPA	2/1/2002	?	TURBINE, COMBINED CYCLE W/ & W/O DUCT FIRING	1,990	LOW SULFUR FUEL (<2.0 GR SULFUR PER 100 SCF OF NAT GAS)	0.00231
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	USE OF LOW SULFUR CONTENT FUELS	0.00240
FPL ENERGY MARCUS HOOK, L.P.	JUNO BEACH, FL	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	LOW SULFUR FUEL	0.00240
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191	LOW SULFUR FUEL	0.00300
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE	2,964	NONE LISTED	0.00243
				(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202	NONE	0.00244
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	NONE LISTED	0.00292
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	FIRING LOW SULFUR PIPELINE NAT GAS	0.00297
				(6) COMBINED TURBINE & DUCT BURNER	1,358	LOW SULFUR PIPELINE NAT GAS	0.03266
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	LOW SULFUR FUEL	0.00301
DEER PARK ENERGY CENTER	HOUSTON	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING LOW-S FUELS	0.00340
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	NONE LISTED	0.00346
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY"	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	LOW SULFUR FUEL	0.00350
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES & DB (1), (2), (3)	1,360	FIRING NAT GAS	0.00382
CRESCENT CITY POWER	ORLEANS,LA	6/6/2005	?	GAS TURBINES - 187 MW (2)	2,006	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	0.00424
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE,OH	12/28/2004	?	TURBINES (4) (MODEL GE 7FA) DUCT BURNERS OFF	344	NONE LISTED	0.00488
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	EXCLUSIVE USE OF NATURAL GAS	0.00569
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	FUEL SULFUR AND H2S CONTENT LIMITS	0.00608
INEOS CHOCOLATE BAYOU FACILITY	BRAZORIA,TX	8/29/2006	?	COGEN TRAIN 2 AND 3 (TURBINE & DB)	280	NATURAL GAS & COMPLEX GAS W/ MAX S CONTENT 5GR/100SCF	0.00693
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	LOW SULFUR FUEL	0.00693
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NATURAL GAS ONLY	0.00900
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	COMBUSTION TURBINE, W/O DUCT BURNER	908	N/A	0.01000
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUELS	0.01746
GULF STATES UTILITIES COMPANY - LOUISIANA STA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	NONE LISTED	0.04406
FREMONT ENERGY CENTER, LLC	BOSTON	8/9/2001	YES	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,440	NONE LISTED	0.00257
				(2) COMBUSTION TURBINES W/O DUCT BURNER	1,440	NONE LISTED	0.00188

Appendix E: Table E-7
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	NO	COMBUSTION TURBINE	2,221	SCR	2.0	BACT-PSD
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9 CT7,(8),(9)	360	SCR AND GOOD COMBUSTION	5.0	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX,CT	2/25/2008	NO	SIEMENS SGT6-5000F CTGS W/ DB	2,205	WATER INJECTION AND SCR	5.9	LAER
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,877	LNB, WATER INJECTION AND SCR	5.9	BACT
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,276	LNB, WATER INJECTION AND SCR	5.9	BACT
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, ABB GT-24 #1&#2 WITH 2 CHILLERS	2,078	SCR WITH AMMONIA INJECTION	5.9	LAER
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	TURBINE, COMBINED CYCLE DISTILLATE OIL (1)	1,801	SCR AND WATER INJECTION.	6.0	BACT-PSD
CAITHNES BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE	2,125	SCR	6.0	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,734	SCR	6.0	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,801	SCR AND WATER INJECTION	6.0	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	SCR AND DLN	6.0	LAER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	SCR	6.0	LAER
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE	1,360	WATER INJECTION SCR	6.0	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE	10/19/2001	?	(2) TURBINE, COMBINED CYCLE	1,707	LNB, SCR	6.0	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,074	SCR AND CEMS	6.0	BACT-PSD
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	NO	TURBINE, COMBINED CYCLE	2,167	DLN BURNERS, SCR WITH AMMONIA INJ	6.0	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	SCR, OIL LIMITED < 1400 HR/YR. PRIM FUEL NAT GAS	6.0	BACT-OTHER
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	STEAM INJECTION AND SCR	8.0	LAER
FP&L TURKEY POINT FOSSIL PLANT - UNIT 5	HOMESTEAD, FL	6/1/2004	NO	(4) COMBUSTION TURBINE	1,830	SCR WITH DLN	8.0	BACT-OTHER
FORSYTH ENERGY PLANT	FORSYTH,NC	9/29/2005	?	TURBINE, COMBINED CYCLE FUEL OIL (3)	2,003	DLN COMBUSTORS AND WATER INJECTION.	8.0	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,440	DRY LNB WITH SCR AND WATER INJECTION	8.4	LAER
ATHENS GENERATING PLANT	GREENE,NY	1/19/2007	NO	FUEL COMBUSTION (OIL)	2,940	DLN, OIL OPERATION LIMITED TO 1080 HRS/YR. STEAM (OR WATER INJ) DURING OIL FIRING	9.0	LAER
EMPIRE POWER PLANT	RENSSELAER,NY	6/23/2005	?	FUEL COMBUSTION (DISTILLATE OIL)	2,099	WATER INJ WITH SCR SYSTEM	9.0	LAER
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	DLN AND SCR	9.0	OTHER
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	DLN AND SCR, 1,080 HR/YR	9.0	LAER
CON ED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	SCR AND DLN, OPERATES 16 HR/YR ON OIL	9.0	LAER
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	1,680	SCR	9.0	LAER
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 AND #2	2,834	LNB WITH WATER INJECTION AND SCR	9.0	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	WATER	9.0	BACT-OTHER
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGEN	1,844	STEAM/WATER INJECTION AND SCR	9.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) EMERGENCY TURBINES USING FUEL OIL, STACK 1-4	2,200	SCR, DLN BURNERS	9.0	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	LNB, SCR	9.0	BACT-PSD
PCLP	MAYS LANDING, NJ	9/19/1995	?	(2) COMBUSTION TURBINE, W/O DUCT BURNER	902	SCR, WATER INJECTION	9.0	BACT-PSD
				(2) TURBINE WITH DUCT BURNER	1,046		23.0	
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	DLN AND SCR	10.0	LAER
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	SCR	10.0	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE NOMINAL 245 MW	1,700	SCR, DRY LOW NOX (DLN 2.6)	10.0	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,898	DLN, SCR, WET INJECTION	10.0	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,898	SCR, DLN, WET INJECTION	10.0	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYCLE	1,811	WATER INJECTION WITH SCR	10.0	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	SCR AND WET INJECTION	10.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	WATER INJECTION AND SCR	10.0	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	DLN BURNERS, SCR	10.0	LAER
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE CT UNITS	1,360	WATER INJECTION + SCR	12.0	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	SCR	12.0	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	WATER INJECTION AND SCR	12.0	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AR	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/DUCT FIRING	1,360	WATER INJECTION W/ SCR	12.5	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE	2,003	DLN COMBUSTORS AND USE OF WATER INJECTION	13.0	BACT-PSD
CAROLINA POWER AND LIGHT - RICHMOND CO. FACILITY	RALEIGH, NC	12/21/2000	?	(2) TURBINE, COMBINED CYCLE	1,819	WATER INJECTION AND SCR	13.0	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,875	WATER INJECTION AND SCR	13.0	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,940	WATER INJECTION AND SCR	13.0	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	DNLB AND SCR ON TURBINES. LNB ON DUCT BURNER	13.6	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	ADVANCED DLN TECHNOLOGY AND SCR	14.0	BACT-PSD
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,236	SCR AND WATER INJECTION	15.0	BACT
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB STAGED COMBUSTION	15.0	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,696	WATER INJECTION, SCR	15.0	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	SCR & WATER INJECTION	15.0	BACT-PSD
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	COMBUSTION TURBINE #1	1,932	SCR	15.0	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	SCR WITH A NOX CEM AND A NOX PEM	16.0	BACT-PSD
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	WATER INJECTION, SCR	16.0	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNER	2,166		42.0	
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURN	1,374	SCR AND DLN BURNERS	21.8	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE	2,080	WATER INJECTION, SCR AND CEMS	22.0	LAER
PREPA	SAN JUAN,PR	4/1/2004	?	TURBINE, COMBINED CYCLE (2)	1904	STEAM INJECTION	34.2	34.2 PPM @ 15% O2
PREPA SAN JUAN REPOWERING PROJECT	SAN JUAN, PR	11/1/2000	?	(2) SWPC 501F COMBUSTION TURBINES	1,694	STEAM INJECTION	34.2	BACT
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,283	SCR & DLN	36.1	BACT-OTHER
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1 ,W/DUCT BURNER	1,464	DLN COMBUSTORS AND BURNERS	37.9	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1 ,W/O DUCT BURNER	1,464		42.0	
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	DLN BURNERS	39.1	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	WATER INJECTION	42.0	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	WATER INJECTION	42.0	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY, DE	3/30/1998	YES	(2) TURBINES, COMBINED CYCLE	827	STEAM INJECTION WHILE FIRING LSDF	42.0	LAER
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	TURBINE, SIMPLE CYCLE DISTILLATE OIL (1)	1,576	WATER INJECTION	42.0	BACT-PSD
TECO-POLK POWER STATION/MULBERRY	TAMPA, FL	12/23/2002	YES	TURBINE, COMBINED CYCLE	1,765	WET INJECTION	42.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	DLN BURNERS VERSION 2.6 BY GE	42.0	BACT-OTHER
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	WATER INJECTION	42.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,121	DLN TECHNOLOGY AND WET INJECTION	42.0	BACT-PSD

Appendix E: Table E-7
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINE #1 & #2	1,127	DILUENT WI SYSTEM USING "QUIET COMBUSTOR" MULTI FUEL NOZZLE CAP; LNB DB	42.0	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE W/ DUCT BURNER	1,515	SCR	42.0	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNERS, WATER INJECTION	42.0	BACT-PSD
SANTEE COOPER RAINEY GEN. STA.	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINE, COMBINED CYCLE	1,360	WATER INJECTION	42.0	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE 1 SHORT-TERM	400	LNB	42.0	BACT-PSD
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION PTS AA-001,002,003 (75%-100% LOAD)	2,248	SCR	42.0	BACT-PSD
				(3) TURBINE, EMISSION PTS AA-001,002,003 (<75% LOAD)	2,248		75.0	
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	54.0	OTHER
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	STACK EMISSIONS (TURBINE @DIST OIL & DUCT BURNER)	610	WATER INJECTION	61.0	BACT-OTHER
				GAS TURBINE	500		65.0	
PONCA CITY MUNICIPAL ELEC. GEN.	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	94	WATER/STEAM INJECTION	65.0	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE III: TURBINES E-1,E-2	720	NONE INDICATED	65.0	NSPS
GOLDEN VALLEY ELEC ASSOC N. POLE POWER PLANT	FAIRBANKS, AK	3/22/2003	?	(2) COMBINED CYCLE COMBUSTION TURBINE	455	WATER INJECTION	67.9	OTHER
PRIME ENERGY	ELMWOOD PARK, NJ	8/29/2001	?	COGEN SYSTEM(COMBUSTION & STEAM TURBINE/GENERATOR)	715	WATER INJECTION	75.0	OTHER
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	?	(2) TURBINES COMBINED CYCLE	1,795	CEM, WATER INJECTION AND GCP	97.0	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, CEMS, CONTINUOUS EMISSION MONITOR, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-8
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
CAITHNESS BELLPORT ENERGY CTR	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE	2,221	OXIDATION CATALYST	2.0	BACT-PSD
CAITHNESS BELLPORT ENERGY CTR	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE NO DB	2,125	OXIDATION CATALYST	2.0	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC	1,568	OXIDATION CATALYST	2.0	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE	1,360	CATALYTIC OXIDATION	2.0	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC	1,568	OXIDATION CATALYST	2.4	BACT-PSD
CONED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OXIDATION CAT, OPERATES 16 HR/YR ON OIL	4.0	LAER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	4.0	LAER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	4.0	BACT
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (100% LOAD)	2,276	OXIDATION CATALYST	4.0	BACT
				(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (75% LOAD)	2,276		5.0	
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, COMBUSTION ABB GT-24 #1&2 WITH 2 CHILLERS	2,078	OXIDATION CATALYST	4.4	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,877	OXIDATION CATALYST	5.0	BACT
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	OXIDATION CATALYST	5.0	OTHER
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	OXIDATION CATALYST	5.0	LAER
GARNET ENERGY, MIDDLETON FACILITY	BOISE	10/19/2001	?	(2) TURBINE, COMBINED CYCLE	1,707	OXIDATION CATALYST, GCP	6.0	BACT-PSD
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	NO	TURBINE, COMBINED CYCLE	2,167	GCP	6.0	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	OXIDATION CATALYST	6.0	BACT-OTHER
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	OXIDATION CATALYST	6.0	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,734	OXIDATION CATALYST	7.0	BACT
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,283	CATALYTIC OXIDATION	7.8	BACT-OTHER
FP&L TURKEY POINT FOSSIL PLANT - UNIT 5	HOMESTEAD, FL	6/1/2004	NO	(4) COMBUSTION TURBINE	1,830	GCP	8.0	BACT-OTHER
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	CATALYTIC OXIDATION SYSTEM	8.0	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	CATALYTIC OXIDIZER	8.0	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	CO CATALYST AND EFFICIENT COMB TECHNIQUES	9.6	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,801	GCP	10.0	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	1,680	0.05% SULFUR DISTILLATE OIL #2 IS USED	10.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	YES	(4) EMERGENCY COMBINED CYCLE GAS TURBINE STACK1-4	1,400	GCP	10.0	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	TURBINE, COMBINED CYCLE	1,801	GOOD COMBUSTION PRACTICES.	10.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) EMERGENCY TURBINES USING FUEL OIL, STACK 1-4	2,200	GCP	10.0	BACT-PSD
GOLDEN VALLEY ELEC ASSN - N POLE POWER PLANT	FAIRBANKS, AK	3/22/2003	?	(2) COMBINED CYCLE COMBUSTION TURBINE	455	OXIDATION CATALYST	10.8	OTHER
COLETO CREEK	GOLIAD,TX	10/31/2005	?	UNIT 1	1,844	GCP AND EFFICIENT PROCESS DESIGN.	11.6	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	GOOD COMBUSTION	14.2	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYCLE	1,811	GOOD COMBUSTION DESIGN AND PRACTICES	14.4	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	CASE III: TURBINE E-1	720	NONE INDICATED	15.0	OTHER
TECO BAYSIDE POWER STATION	TAMPA, FL	3/30/2001	YES	(7) TURBINE, COMBINED CYCLE	1,360	GCP AND DESIGN	15.0	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	NONE INDICATED	15.0	BACT-OTHER
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	15.0	LAER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9 CT7,(8),(9)	360	OXIDATION CATALYST	15.0	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,074	NONE INDICATED	15.6	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE	2,003	EFFICIENT COMBUSTION PROCESS DESIGN	15.7	BACT-PSD
				(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,003		25.1	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	CASE III: TURBINE E-2	720	NONE INDICATED	15.7	OTHER
FORSYTH ENERGY PLANT	FORSYTH,NC	9/29/2005	?	TURBINE, COMBINED CYCLE FUEL OIL (3)	2,003	EFFICIENT COMBUSTION PROCESS DESIGN.	15.7	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	16.0	OTHER
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,440	OXIDATION CATALYST	16.0	LAER
				COMBUSTION TURBINE W/ HEAT RECOVERY BOILER (<75%LOAD)	1,440		31.4	
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,875	COMBUSTION CONTROL	16.5	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE	2,080	NONE INDICATED	16.9	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,898	COMBUSTION CONTROLS	17.0	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,898	COMBUSTION CONTROLS	17.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	GOOD COMBUSTION	20.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,121	GCP	20.0	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	COMBUSTION CONTROLS	20.0	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE NOMINAL 245 MW	1,700	COMBUSTION CONTROLS	20.0	BACT-PSD
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	COMBUSTION DESIGN	20.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION DESIGN, GCP	20.0	BACT-PSD
CAROLINA POWER AND LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINE, COMBINED CYCLE	1,819	COMBUSTION CONTROL	20.0	BACT-PSD
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	COMBUSTION TURBINE #1	1,932	NONE INDICATED	20.0	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES COMBINED CYCLE	1,795	COMBUSTION CONTROLS	20.0	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE (100% LOAD)	1,940	COMBUSTION CONTROL	20.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE (85% LOAD)	1,940		22.0	
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE	1,696	GCP	20.0	BACT-PSD
				TURBINE, COMBINED CYCLE DUCT BURNER	1,696		30.0	
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC	1,568	OXIDATION CATALYST	20.6	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC	1,568	OXIDATION CATALYST	24.3	BACT-PSD
PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION	24.3	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP	24.3	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB, GCP	25.0	BACT-PSD
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINE #1 & #2	1,127	DILUENT WI USING "QUIET COMBUSTOR" MULTI FUEL NOZZLE CAP; LNB DB	25.0	BACT-PSD
PREPA SAN JUAN REPOWERING PROJECT	SAN JUAN, PR	11/1/2000	?	(2) SWPC 501F COMBUSTION TURBINES (100% LOAD)	1,694	NONE INDICATED	25.0	BACT
				(2) SWPC 501F COMBUSTION TURBINES (60%-100% LOAD)	1,694		60.0	
FORSYTH ENERGY PLANT	FORSYTH,NC	9/29/2005	?	TURBINE & DUCT BURNER COMBINED CYCLE FUEL OIL 3	2,003	EFFICIENT COMBUSTION PROCESS DESIGN	25.1	BACT-PSD
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	(2) COMBUSTION TURBINE, W/O DUCT BURNER	902	NONE INDICATED	25.2	BACT-PSD

Appendix E: Table E-8
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
				(2) TURBINE WITH DUCT BURNER	1,046		34.0	
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	GOOD COMBUSTION	25.8	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1 ,W/DUCT BURNER	1,464	GCP	25.9	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1 ,W/O DUCT BURNER	1,464		27.0	
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE W/ DUCT BURNER	1,515	OXIDATION CATALYST	27.0	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	EFFICIENT COMBUSTION	27.7	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	COMBUSTION DESIGN, GCP	30.0	BACT-PSD
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINT AA-001,002,003 (75%-100% LOAD)	2,248	NONE INDICATED	36.0	BACT-PSD
				(3) TURBINE, EMISSION POINT AA-001,002,003 (<75% LOAD)	1,686		150.0	
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP, CLEAN BURNING FUELS	37.0	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURN	1,374	NONE INDICATED	38.0	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE CT UNITS	1,360	EFFICIENT COMBUSTION	39.7	BACT-PSD
TECO-POLK POWER STATION/MULBERRY	TAMPA, FL	12/23/2002	YES	TURBINE, COMBINED CYCLE	1,765	GOOD COMBUSTION	40.0	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINE, COMBINED CYCLE	1,360	COMBUSTION TECHNOLOGY AND CLEAN FUELS	40.0	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (100% LOAD)	1,480	GCP	40.0	BACT-PSD
				TURBINE, COMBINED CYCLE (<75% LOAD)	1,480		300.0	
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	GCP AND COMBUSTION CONTROLS	42.0	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNER	2,166		90.0	
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 AND #2	2,834	LNB & GCP	50.0	BACT-PSD
PRIME ENERGY	ELMWOOD PARK, NJ	8/29/2001	?	COGEN SYSTEM(COMBUSTION & STEAM TURBINE/GENERATOR)	715	WATER INJECTION	50.0	OTHER
ATHEN GENERATING CO, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	CLEAN BURNING FUELS AND EFFICIENT COMBUSTION	50.0	BACT
				(3) SWPC 510G COMBUSTION TURBINES (75% LOAD)	2,880	TECHNIQUES, 1,080 HR/YR	92.0	
PREPA	SAN JUAN,PR	4/1/2004	?	TURBINE, COMBINED CYCLE (2)	1,904		60.0	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION TECHNOLOGY, CLEAN FUELS	83.8	BACT-PSD
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	YES	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	GCP	90.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	GOOD COMBUSTION OF CLEAN FUELS	90.0	BACT-OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,547	GOOD COMBUSTION CONTROLS	90.0	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE 1 SHORT-TERM	400	LNB	90.0	BACT-PSD
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	GAS TURBINE	500	NONE INDICATED	97.0	BACT-OTHER
				STACK EMISSIONS (TURBINE @DIST OIL & DUCT BURNER)	610		123.0	
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	COMBUSTION CONTROLS	100.0	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/DUCT FIRING	1,360	EFFICIENT COMBUSTION	156.1	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	94	TURBINE DESIGN	975.3	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-9
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMBUSTION. CLEAN FUELS	1.6	BACT-OTHER
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	2.0	OTHER
CONED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OXIDATION CATALYST, OPERATES 16 HR/YR ON OIL	2.0	LAER
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE	1,360	CATALYTIC OXIDATION	2.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	YES	(4) EMERGENCY COMBINED CYCLE GAS TURBINE STACK1-4	1,400	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) EMERGENCY TURBINES USING FUEL OIL, STACK 1-4	2,200	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-PSD
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9 CT7,(8),(9)	360	GCP	2.2	BACT-OTHER
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYCLE	1,811	GCP	2.5	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE	2,080	GOOD AIR POLLUTION CONTROL PRACTICES	2.6	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,877	OXIDATION CATALYST FOR CO	2.9	BACT
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP	2.9	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,074	NONE INDICATED	2.9	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1 ,W/O DUCT BURNER	1,464	GOOD COMBUSTION DESIGN AND OPERATIONS	2.9	BACT-PSD
					1,464		8.5	
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	GCP	3.0	OTHER
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	OXIDATION CATALYST	3.0	LAER
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	CO CATALYST AND EFFICIENT COMB TECHNIQUES	3.0	LAER
TECO BAYSIDE POWER STATION	TAMPA, FL	3/30/2001	YES	(7) TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION DESIGN AND OPER PRACTICES	3.0	BACT-PSD
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	OXIDATION CATALYST	3.0	OTHER
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINE #1 & #2, W/ HRSG	1,127	EFFECTIVE COMBUSTION OF FUELS	3.1	BACT-PSD
					1,127		7.3	
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,283	CATALYTIC OXIDATION	3.1	BACT-OTHER
PEDRICKTOWN COGENERATION PLANT (PCLP)	MAYS LANDING, NJ	9/19/1995	?	(2) COMBUSTION TURBINE, W/O DUCT BURNER	902	NONE INDICATED	3.3	BACT-PSD
					1,046		7.5	
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	COMBUSTION DESIGN	3.5	BACT-OTHER
CAROLINA POWER AND LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINE, COMBINED CYCLE	1,819	COMBUSTION CONTROL	3.5	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,875	COMBUSTION CONTROL	3.5	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES COMBINED CYCLE	1,795	COMBUSTION CONTROLS	3.5	BACT-PSD
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	NO	TURBINE, COMBINED CYCLE	2,167	GOOD COMBUSTION/DESIGN AND CLEAN FUELS	3.5	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SGT6-5000F TURBINE #1 AND #2 W/ 445 MMBTU/HR DB	2,117	CO CATALYST	3.6	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	COMBUSTION CONTROLS	3.6	BACT-OTHER
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE NOMINAL 245 MW	1,700	GCP	3.6	BACT-OTHER
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP, CLEAN BURNING FUEL	4.3	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,440	OXIDATION CATALYST	4.4	LAER
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURN	1,374	NONE INDICATED	4.5	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION TECHNOLOGY, CLEAN FUELS	4.6	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINE, COMBINED CYCLE	1,360	COMBUSTION TECHNOLOGY, CLEAN FUELS	4.6	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	CATALYTIC OXIDATION	4.9	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,801	GCP	5.0	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2)ABB GT-24 #1&2 W/ 2 CHILLERS (75-100% LOAD, 60-104°F)	2,078	OXIDATION CATALYST FOR CO	5.4	BACT
				(2) ABB GT-24 #1&2 W/ 2 CHILLERS (75-100% LOAD, 0-59°F)	2,078		5.9	
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	5.5	LAER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	5.6	LAER
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	NONE INDICATED	5.6	BACT-PSD
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	(3) CTGS, EACH WITH HRSG & NATL GAS-FIRED DB	2,003	EFFICIENT COMBUSTION DESIGN	6.0	BACT-PSD
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,276	OXIDATION CATALYST FOR CO	6.0	BACT
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,003	EFFICIENT COMBUSTION DESIGN	6.0	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	6.0	LAER
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	6.0	BACT-PSD
PREPA SAN JUAN REPOWERING PROJECT	SAN JUAN, PR	11/1/2000	?	(2) SWPC 501F COMBUSTION TURBINES (100% LOAD)	1,694	NONE INDICATED	6.2	BACT
				(2) SWPC 501F COMBUSTION TURBINES (60%-100% LOAD)	1,694		10.0	
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	1,680	0.05% SULFUR DISTILLATE OIL #2 IS USED	6.6	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NATURAL GAS COMBUSTION	6.9	BACT-PSD
SITHE EDGAR DEV., LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,734	OXIDATION CATALYST	7.0	BACT
FPL SANFORD PLANT	DEBARY, FL	9/14/1999	YES	(4) COMBUSTION TURBINES COMBINED CYCLE	1,776	GCP	7.0	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,940	COMBUSTION CONTROL	7.0	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 AND #2	2,834	GCP	7.4	SIP
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE III: TURBINES E-1,E-2	720	NONE INDICATED	7.6	OTHER
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	COMBUSTION CONTROL	8.0	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	GOOD COMBUSTION AND DESIGN	8.5	OTHER
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE 1 SHORT-TERM	400	NONE INDICATED	8.6	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE	10/19/2001	?	(2) TURBINE, COMBINED CYCLE	1,707	GCP	9.2	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	EFFICIENT COMBUSTION	9.4	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,696	GOOD COMBUSTION	10.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	WATER INJECTION AND SCR	10.0	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	CATALYTIC OXIDATION SYSTEM	10.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION DESIGN, GCP	10.0	BACT-PSD
EMPIRE GENERATING CO. LLC	RENSSELAER, NY	6/23/2005	NO	FUEL COMBUSTION (DISTILLATE OIL) DUCT BURNING	646	OXYIDATION CATALYST	12.0	LAER
				FUEL COMBUSTION (DISTILLATE OIL)	2,099	OXIDATION CATALYST	2.0	LAER
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	NO	TURBINE, COMBINED CYCLE W/O DUCT BURNER	2,166	GCP AND COMBUSTION CONTROL	12.2	BACT-PSD
					2,516		17.9	
NEW ATHENS GENERATING CO. LLC	GREENE, NY	1/19/2007	NO	(3) 501G TURBINES (245 MW), HRSGS, & STGS (115 MW)	2,940	GOOD COMBUSTION CONTROL	13.0	LAER
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	EFFICIENT COMB TECHNIQUES, 1,080 HR/YR	13.0	LAER
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE CT UNITS	1,360	EFFICIENT COMBUSTION	13.3	BACT-PSD

Appendix E: Table E-9
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINT AA-001,002,003 (100% LOAD)	2,248	NONE INDICATED	15.0	BACT-PSD
					2,248		100.0	
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	GAS TURBINE	500	NONE INDICATED	15.6	BACT-OTHER
					610		40.6	
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480	GCP	16.0	BACT-PSD
					1,480		32.0	
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE W/ DUCT BURNER	1,515	GCP	20.3	BACT-PSD
TECO-POLK POWER STATION/MULBERRY	TAMPA, FL	12/23/2002	YES	TURBINE, COMBINED CYCLE	1,765	GOOD COMBUSTION	21.8	BACT-PSD
PRIME ENERGY	ELMWOOD PARK, NJ	8/29/2001	?	COGEN SYSTEM(COMBUSTION & STEAM TURBINE/GENERATOR)	715	WATER INJECTION	26.2	OTHER
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	GCP	28.9	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,547	GOOD COMBUSTION CONTROLS	30.0	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AR	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/DUCT FIRING	1,360	EFFICIENT COMBUSTION	30.4	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	94	TURBINE DESIGN	252.8	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-10
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	(2) COMBUSTION TURBINE, W/O DUCT BURNER	902	NONE INDICATED	0.0050	BACT-PSD
				(2) TURBINE WITH DUCT BURNER	1,046		0.0300	
CAITHNESS BELLPORT ENERGY CTR	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE	2221	LOW SULFUR FUEL	0.0055	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMB & CLEAN FUELS. OIL USE LIMITED TO < 1400 HR/YR. PRIMARY FUEL NAT GAS	0.0073	BACT-OTHER
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.0076	OTHER
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP, CLEAN FUEL	0.0085	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	NONE INDICATED	0.0086	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,121	CLEAN FUELS	0.0089	BACT-PSD
TECO-POLK POWER STATION/MULBERRY	TAMPA, FL	12/23/2002	YES	TURBINE, COMBINED CYCLE	1,765	GOOD COMBUSTION	0.0090	BACT-PSD
CAROLINA POWER AND LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINE, COMBINED CYCLE	1,819	COMBUSTION CONTROL	0.0090	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,875	COMBUSTION CONTROL	0.0090	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,074	USE OF DRIFT ELIMINATORS	0.0105	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	GOOD COMBUSTION	0.0109	BACT-PSD
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINE #1 & #2	1,127	S ULFUR CONTENT < 0.3% S BY WT	0.0133	BACT-OTHER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9 CT7,(8),(9)	360	LOW ASH FUEL OIL	0.0139	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE III: TURBINES E-1,E-2	720	NONE INDICATED	0.0139	NSPS
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	NONE INDICATED	0.0157	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUEL	0.0160	BACT-OTHER
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	COMBUSTION TURBINE #1	1,932	NONE INDICATED	0.0171	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AR	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/DB	1,360	EFFICIENT COMBUSTION	0.0185	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	COMBUSTION CONTROLS, LOW SULFUR FUELS	0.0188	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES COMBINED CYCLE	1,795	NONE INDICATED	0.0189	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,898	CLEAN FUELS AND GOOD COMBUSTION	0.0190	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,898	CLEAN FUELS, COMBUSTION CONTROLS AMMONIA SLIP < 5 PPMVD	0.0190	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINES	2,834	LOW SULFUR FUELS	0.0200	BACT-PSD
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.0200	BACT-PSD
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	NO	TURBINE, COMBINED CYCLE	2,167	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	0.0203	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE CTG NOMINAL 245 MW	1,700	INHERENTLY CLEAN FUELS, COMBUSTION CONTROLS AMMONIA SLIP BELOW 5 PPMVD	0.0212	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,283	LOW ASH FUEL	0.0219	BACT-OTHER
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,940	COMBUSTION CONTROL	0.0235	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,003	CLEAN-BURNING, LOW SULFUR FUELS (< 0.015%S), GCP	0.0248	BACT-PSD
				(3) TURBINE, COMBINED CYCLE	2,003		0.0358	
FORSYTH ENERGY PLANT	FORSYTH,NC	9/29/2005	?	TURBINE & DUCT BURNER COMBINED CYCLE	2003	CLEAN-BURNING, LOW SULFUR FUELS (< 0.015% S), GOOD COMBUSTION PRACTICES.	0.0248	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 5 -GE FRAME 7F TURBINES W/ HRSG	1568	NONE INDICATED	0.0249	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE	2,080	NONE INDICATED	0.0255	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 4 -GE FRAME 7F TURBINES W/ HRSG-	1568	NONE INDICATED	0.0261	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE CT UNITS	1,360	CLEAN FUELS	0.0280	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	GOOD COMBUSTION CLEAN FUEL: DISTILLATE OIL < 0.05% S BY WT	0.0295	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	TURBINE, COMBINED CYCLE	1801	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.03	OTHER
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,801	CLEAN FUEL AND GCP	0.0300	BACT-OTHER
GARNET ENERGY, MIDDLETON FACILITY	BOISE	10/19/2001	?	(2) TURBINE, COMBINED CYCLE	1,707	GCP	0.0307	BACT-PSD
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	GCP AND LOW SULFUR FUEL	0.0320	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNER	2,166		0.0423	
CON ED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OPERATES 16 HR/YR ON OIL	0.0326	BACT
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NONE INDICATED	0.0327	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	94	LOW ASH FUEL	0.0330	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1 ,W/DUCT BURNER	1,464	FIRING NATURAL GAS IN THE DUCT BURNERS	0.0331	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	CLEAN FUELS, GCP	0.0338	BACT-PSD
PRIME ENERGY	ELMWOOD PARK, NJ	8/29/2001	?	COGEN SYSTEM	715	WATER INJECTION	0.0350	OTHER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE W/ DB	1,515	GCP	0.0350	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH,NC	9/29/2005	?	TURBINE, COMBINED CYCLE FUEL OIL (3)	2003	USE OF ONLY CLEAN-BURNING, LOW S FUELS AND GOOD COMBUSTION PRACTICES.	0.0358	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,877	NONE INDICATED	0.0361	BACT
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	YES	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	NO. 2 FUEL OIL - LOW ASH FUEL, GCP	0.0365	BACT-PSD
LAKE ROAD GENERATING CO, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,276	NONE INDICATED	0.0377	BACT
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COGENERATION	1,844	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GCP	0.0390	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, ABB GT-24 #1&#2 WITH 2 CHILLERS	2,078	LOW SULFUR (0.05%W) OIL AS BACK-UP	0.0392	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.0400	BACT
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUELS	0.0400	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.0401	BACT
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	EFFICIENT COMBUSTION	0.0420	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE W/O DB	1,374	NONE INDICATED	0.0437	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	CLEAN BURNING FUEL, GCP	0.0442	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.0470	BACT
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,734	NONE INDICATED	0.0500	BACT
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) EMERGENCY TURBINES, STACK 1-4	2,200	FIRING NAT GAS	0.0505	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480	GCP	0.0530	BACT-PSD
				TURBINE, COMBINED CYCLE (<75% LOAD)	1,480		0.0790	
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	STACK EMISSIONS (TURBINE @DIST OIL & DB)	610	S CONTENT NOT TO EXCEED 0.3% BY WEIGHT	0.0540	BACT-OTHER
				GAS TURBINE	500		0.0630	
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBUSTION TURBINE, W/ AND W/O DB	1,779	CLEAN FUELS	0.0570	OTHER
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	CLEAN FUEL AND EFFICIENT COMBUSTION TECHNIQUES	0.0580	BACT
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE 1 SHORT-TERM	400	NONE INDICATED	0.0650	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	1,680	0.05% SULFUR DISTILLATE OIL #2 IS USED	0.0667	BACT-PSD
ATHENS GENERATING, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	CLEAN AND EFFICIENT COMBUSTION TECHNIQUES, 1,080 HR/YR	0.0750	BACT
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	YES	(4) EMERGENCY GAS TURBINE STACK1-4	1,400	FIRING NAT GAS	0.0793	BACT-PSD

Appendix E: Table E-10
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,547	GOOD COMBUSTION CONTROLS	0.1263	BACT-PSD

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-11
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	(2) COMBUSTION TURBINE, W/O DUCT BURNER	902	NONE INDICATED	0.0009	BACT-PSD
				(2) TURBINE WITH DUCT BURNER	1,046		0.0400	
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SIEMENS SGT6-5000F TURBINE #1 AND #2 W/ DB	2,117	ULTRA LOW SULFUR FUEL (0.0015 % SULFUR BY WEIGHT)	0.0015	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,074	USE OF LOW SULFUR FUELS	0.0100	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	NONE INDICATED	0.0124	BACT-OTHER
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,003	VERY LOW SULFUR NO. 2 FUEL OIL (0.015% S) LIMITED TO 1,200	0.0154	BACT-PSD
				(3) TURBINE, COMBINED CYCLE	2,003	H/YR PER TURBINE	0.0162	
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	3 COMBINED-CYCLE COMB TURBINES W/DB	2,003	VERY LOW-SULFUR OIL (0.015% SULFUR) 1,200 HR/YR	0.0162	BACT-PSD
				3 COMBINED-CYCLE COMB TURBINES W/DB	2,003	VERY LOW S FUEL OIL (0.015% S) 1,200 H/YR PER TURBINE	0.0154	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.0203	BACT
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	LOW SULFUR FUEL (< 0.05% SULFUR BY WEIGHT)	0.0272	OTHER
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	FIRING FUEL OIL WITH 0.05% S; 720 H/YR MAX	0.0336	BACT-PSD
CAITHNESS BELLPORT, LLC	SUFFOLK, NY	5/10/2006	NO	COMBINE CYCLE W/ DB	2,125	LOW SULFUR FUEL	0.0360	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE	1,844	LNG/LPG AS PRIMARY FUEL, 0.04% S NO. 2 OIL AS BACKUP	0.0382	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.0420	BACT
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE TURBINE, W/ AND W/O DB	2,423	CLEAN FUELS	0.0440	OTHER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,283	LOW SULFUR FUEL FUEL OIL < 0.05% S BY WT	0.0463	BACT-OTHER
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE	2,080	NONE INDICATED	0.0475	BACT-PSD
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	BACT IS FUEL < 0.05% S BY WT	0.0479	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNER	2,166		0.0556	
TECO-POLK POWER STATION/MULBERRY	TAMPA, FL	12/23/2002	YES	TURBINE, COMBINED CYCLE	1,765	FUEL SPEC: LOW SULFUR FUEL OIL	0.0480	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CTR	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	COMBUSTION OF LOW S FUELS: 0.5% BY WT S	0.0487	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUELS - 0.05% S BY WT	0.0489	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	USE OF LOW SULFUR OIL	0.0493	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) EMERGENCY TURBINES USING FUEL OIL, STACK 1-4	2,200	LOW S FUEL	0.0495	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	LOW SULFUR FUELS AND GCP, 1,080 HR/YR	0.0500	BACT
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	FUEL SPECIFICATION: LOW SULFUR FUELS	0.0500	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.0500	BACT-OTHER
JAMES CITY ENERGY PARK	WELLESLEY, MA	12/1/2003	NO	TURBINE, COMBINED CYCLE	2,167	LOW SULFUR FUELS	0.0510	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,801	LOW SULFUR FUEL	0.0510	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,877	FUEL SULFUR LIMITED TO < 0.05% FOR FO	0.0513	BACT
LAKE ROAD GENERATING COMPANY,L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,276	LOW SULFUR FUEL < 0.05% S	0.0514	BACT
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	CLEAN FUELS -- 0.05% S OIL	0.0516	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINEABB GT-24 #1&#2 WITH 2 CHILLERS	2,078	LOW SULFUR OIL (0.05%W)	0.0520	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,940	LOW SULFUR FUEL: 0.05% S FUEL OIL	0.0520	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 AND #2	2,834	LOW SULFUR FUELS	0.0520	BACT-PSD
SITHE, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,734	NONE INDICATED	0.0522	BACT
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	SULFUR IN FUEL OIL LIMITED TO 0.05%	0.0530	BACT-PSD
CAROLINA POWER AND LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINE, COMBINED CYCLE	1,819	LOW S FUEL: < 0.05% S FUEL OIL	0.0540	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,875	LOW SULFUR FUEL: < 0.05% S FUEL OIL	0.0540	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE	10/19/2001	?	(2) TURBINE, COMBINED CYCLE	1,707	LOW SULFUR FUEL, 0.05% BY WEIGHT	0.0544	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	LOW SULFUR FUEL < 0.05% S	0.0550	BACT
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,236	CLEAN FUELS, GOOD COMBUSTION < 0.05% S	0.0568	
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9 CT7,(8),(9)	360	0.05% SULFUR OIL	0.0583	BACT-OTHER
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE III: TURBINE E-1,E-2	720	NONE INDICATED	0.0583	NSPS
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW SULFUR FUELS	0.0647	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	1,680	0.05% SULFUR DISTILLATE OIL #2 USED	0.0679	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	0.0680	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1 ,W/DUCT BURNER	1,464	NAT GAS IN DBS & LOW S (0.05%) FUEL BACKUP FOR TURBINES	0.0727	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUEL	0.0728	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURN	1,374	MAX SULFUR CONTENT OF FUEL OIL < 0.05% S BY WEIGHT	0.0735	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0776	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0776	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	YES	(4) EMERGENCY COMBINED CYCLE GAS TURBINE	1,400	LOW S FUEL	0.0779	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE 1 SHORT-TERM	400	LOW SULFUR FUEL	0.0883	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	94	LOW SULFUR FUEL - < .1% SULFUR IN FUEL OIL	0.1100	BACT-PSD
PRIME ENERGY	ELMWOOD PARK, NJ	8/29/2001	?	COGEN(COMBUSTION & STEAM TURBINE/GENERATOR)	715	SULFUR <= 0.15% BY WEIGHT WATER INJECTION	0.1552	OTHER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE W/ DUCT BURNER	1,515	GCP, LOW SULFUR FUEL	0.2030	BACT-PSD
PINE STATE POWER	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINE #1 & #2	1,127	SULFUR CONTENT < 0.3% S BY WT	0.3177	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES COMBINED CYCLE	1,795	SULFUR CONTENT OF FUEL≤ 0.2% BY WEIGHT	0.4028	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AR	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/DUCT FIRING	1,360	DIESEL FIRING, LIMIT SULFUR CONTENT	--	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE CT UNITS	1,360	DIESEL, LIMITED HOURS	--	BACT-PSD
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	YES	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	GCP FUEL S LIMIT: < 0.33% S BY WT	--	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	LOW S FUEL OIL OR NATL GAS; COMBUSTION OF CLEAN FUELS	--	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,696	CLEAN FUEL: NO. 2 FUEL OIL WITH 0.05% S CONTENT	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	LOW SULFUR FUELS: FUEL OIL < 0.05% S CONTENT	--	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	PERMIT LIMIT IS LOW SULFUR FUELS: OIL < 0.05% SULFUR	--	BACT-PSD
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	LOW SULFUR FUEL OIL: 0.05% S BY WT	--	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	CLEAN FUELS SULFUR FUEL LIMIT	--	BACT-OTHER
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,898	CLEAN FUEL - < 0.05 % S FUEL	--	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,898	LOW SULFUR FUEL: < 0.05%	--	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYCLE	1,811	ULSD FUEL OIL (0.05% S BY WEIGHT)	--	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	FUEL SPECIFICATIONS: DISTILLATE OIL < 0.05% S BY WT	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	LOW SULFUR FUEL	--	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUEL OIL, LESS THAN 0.05% SULFUR	--	BACT-OTHER
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	COMBUSTION TURBINE #1	1,932	FUEL OIL SULFUR CONTENT < 0.5% BY WEIGHT.	--	OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	ULSD FUEL (< 15 PPM S) <1400 HR/YR. PRIMARY FUEL NAT GAS	--	BACT-OTHER

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Appendix E: Table E-12
CPV Valley Energy Center
Recent RACT/BACT/LAER Determinations for Fuel Oil-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,918	CLEAN FUELS -- < 0.05% S OIL	0.0001	BACT-PSD
			NO	COMBUSTION TURBINE W/ DB	2,221	LOW SULFUR FUEL	0.0004	BACT-PSD
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	NO	COMBUSTION TURBINE W/O DB	2,125	LOW SULFUR FUEL (0.04%).	0.015	BACT-PSD
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 W/ 2 CHILLERS	2,078	LOW SULFUR OIL (0.05%W)	0.0009	BACT-PSD
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,276	NONE INDICATED	0.0016	BACT
PANDA-BRANDYWINE	MARYLAND	6/17/1994	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.0030	OTHER
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	FUEL OIL S CONTENT: 0.05%; 720 H/YR MAX	0.0033	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINES & DUCT BURNER	1,360	INHERENTLY LIMITED BY FUEL OIL SULFUR LIMITATION	0.0040	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.0062	BACT
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURN	1,374	NONE INDICATED	0.0069	SIP
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP, CLEAN BURNING LOW SULFUR FUELS	0.0074	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	LOW S FUELS & EFFICIENT COMB TECHNIQUES, 1,080 HR/YR	0.0080	BACT
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0089	BACT-OTHER
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUEL	0.0089	BACT-PSD
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	(2) TURBINE WITH DUCT BURNER	1,046	NONE INDICATED	0.0100	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW-SULFUR FUELS	0.0103	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.0120	BACT
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	2,272	LOW SULFUR FUEL < 0.05% S	0.0130	BACT
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE, W/ & W/O DB	1,779	CLEAN FUELS	0.0140	OTHER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.0152	BACT
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NONE INDICATED	0.0170	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUEL OIL	0.0214	BACT-OTHER
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	FUEL SPECIFICATION: LOW SULFUR FUEL	0.0230	BACT-PSD

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, SCR = SELECTIVE CATALYTIC REDUCTION

Appendix E: Table E-13
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	NO_x EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
MAPEE ALCOHOL FUEL, INC.	MOORE CO., TX	3/27/1981	?	AUXILIARY BOILER	35	LOW EXCESS AIR	0.0006	BACT-PSD
MINNESOTA STEEL INDUSTRIES, LLC	ITASCA,MN	9/7/2007	NO	SMALL BOILERS & HEATERS(<100 MMBTU/H)	99		0.0035	BACT-PSD
CHILDREN'S HOSPITAL LOS ANGELES	LOS ANGELES CO., CA	12/2/1999	?	BOILER	34	SCR	0.0085	LAER
CHILDREN'S HOSPITAL LOS ANGELES	LOS ANGELES CO., CA	12/2/1999	?	(2) BOILERS	24	SCR	0.0085	LAER
COCA COLA	LOS ANGELES CO., CA	11/23/1999	?	SCOTCH MARINE CUSTOM FIRE-TUBE BOILER	32	COEN - LNB, PEERLESS - SCR	0.0085	BACT-PSD
LACORR PACKAGING	LOS ANGELES CO., CA	7/12/2000	?	CLEAVER BROOKS MODEL CB-LE 500 BOILER	21	SCR	0.0090	LAER
MEDIMMUNE FREDERICK CAMPUS	FREDERICK,MD	1/28/2008	NO	4 NATURAL GAS BOILERS EACH RATED AT 29.4 MMBTU/HR	29	ULTRA LOW NOX BURNERS ON EACH OF THE FOUR IDENTICAL BOILERS	0.0110	LAER
CPV WARREN	WARREN,VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 2	97	CEM SYSTEM	0.0110	N/A
CPV WARREN	WARREN,VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 3	62	CEM SYSTEM	0.0110	N/A
CAITHNES BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	NO	AUXILIARY BOILER	29	LOW NOX BURNERS & FLUE GAS RECIRCULATION	0.0110	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	AUXILIARY BOILER	99	NATURAL GAS ONLY	0.0110	LAER
NATION WIDE BOILER	ALAMEDA CO., CA	3/15/2000	?	PORTABLE BOILER	29	NONE INDICATED	0.0110	LAER
HI-COUNTRY	RIVERSIDE CO., CA	12/16/1999	YES	FIRE TUBE BOILER	21	LNB	0.0110	LAER
UNIVERSITY OF CALIFORNIA IRVINE MEDICAL CENTER	ORANGE CO., CA	1/16/1992	?	ZURN/KEYSTONE WATERTUBE BOILER	49	SIX ALZETA CORPORATION CERAMIC FIBER RADIANT LNB	0.0110	BACT-PSD
KAL KAN FOODS, INC.	LOS ANGELES CO., CA	7/24/1990	?	COEN DAF LOW NOX WATER-TUBE BOILER	79	SCR, LNB	0.0110	LAER
MERCK - RAHWAY PLANT	UNION CO., NJ	1/14/1997	?	(3) BOILERS	100	ULTRA LNB	0.0111	OTHER
KALKAN FOODS INC.	LOS ANGELES CO., CA	7/24/1990	?	BABCOCK AND WILCOX WATER-TUBE BOILER	79	SCR, FLUE GAS RECIRC COEN DAF BURNER	0.0111	LAER
LIBERTY CONTAINER CO	LOS ANGELES CO., CA	3/17/2000	?	CLEAVER BROOKS CB (LE) 700-400	16	ULTRA LNB	0.0150	LAER
BUMBLE BEE SEAFOODS, INC.	LOS ANGELES CO., CA	3/10/2000	?	SUPERIOR MOHAWK MODEL 4X-2007-S150 FIRE TUBE BOILER	16	LNB AND FGR	0.0150	LAER
LA PORTE POLYPROPYLENE PLANT	HARRIS CO., TX	11/5/2001	NO	PACKAGE BOILER BO-4	60	ULTRA LNB	0.0150	OTHER
SANTA MONICA - UCLA MEDICAL CENTER	LOS ANGELES CO., CA	1/28/2000	?	CLEAVER BROOKS MODEL CE (LE) 200-400 FIRE-TUBE BOILER	16	LNB AND FGR	0.0180	LAER
ADM CORN PROCESSING - CEDAR RAPIDS	LINN,IA	6/29/2007	NO	NATURAL GAS BOILER (292.5 MMBTU/H)	293	ADVANCED ULNB WITH FGR AND GOOD COMBUSTION PRACTICES.	0.0200	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	AUXILIARY STEAM BOILER	80	LNB AND FGR	0.0200	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	6/19/1997	?	(2) BOILER	13	LNB, CLEAN FUEL	0.0300	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	6/19/1997	?	(2) BOILER	12	CLEAN FUEL, LNB	0.0300	BACT-PSD
VENTURA COASTAL CORP.	CALIFORNIA	11/17/1988	?	CLEAVER-BROOKS MODEL CB-400 BOILER	27	NONE INDICATED	0.0327	OTHER
PRO TEC COATING COMPANY	PUTNAM CO., OH	2/15/2001	?	(4) BOILERS	21	LNB	0.0330	SIP
COTTAGE HEALTH CARE - PUEBLO STREET	SANTA BARBARA,CA	5/16/2006	NO	BOILER: 5 TO < 33.5 MMBTU/H	25	ULTRA-LOW NOX BURNER	0.0332	BACT-PSD
GENENTECH, INC.	SAN MATEO,CA	9/27/2005	NO	BOILER:>= 50 MMBTU/H	97	ULTRA LOW NOX BURNERS: NATCOM P-97-LOG-35-2127	0.0332	BACT-PSD
TOMA-TEK INC.	CALIFORNIA	3/1/1989	?	WATER TUBE BOILER W/ DYNASWIRL BURNER	90	LNB, GCP	0.0339	BACT-PSD
HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	AUXILIARY BOILER	49	GCP	0.0340	BACT-PSD
FREMONT ENERGY CENTER, LLC	SANDUSKY CO., OH	8/9/2001	?	AUXILIARY BOILER	80	LNB	0.0340	BACT-PSD
DEMING ENERGY FACILITY	LUNA CO., NM	12/29/2000	?	AUXILIARY BOILER	44	DRY LNB, NATURAL GAS COMBUSTION AND GOOD ENGINEERING PRACTICE	0.0340	BACT-PSD
VENTURA COASTAL CORP.	CALIFORNIA	8/31/1987	?	CLEAVER-BROOKS MODEL CB-400 BOILER	31	FGR OXYGEN TRIM	0.0341	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE,OH	12/28/2004	?	BOILERS (2)	31		0.0350	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE CO., OH	12/13/2001	?	(2) BOILER	37	NONE INDICATED	0.0350	BACT-PSD
HONDA MANUFACTURING OF ALABAMA, LLC	TALLEDEGA CO., AL	2/29/2000	?	BOILERS	10	NATURAL GAS FUEL ONLY, LNB	0.0350	BACT-PSD
THYSSENKRUPP STEEL AND STAINLESS USA, LLC	MOBILE,AL	8/17/2007	NO	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	65	ULNB & EGR – SAME FLUE GAS RECIRCULATION (FGR)	0.0350	BACT-PSD
NUCOR DECATUR LLC	MORGAN,IA	6/12/2007	NO	VACUUM DEGASSER BOILER	95	ULTRA LOW NOX BURNERS	0.0350	BACT-PSD
HARRAH'S OPERATING COMPANY, INC.	CLARK,NV	1/4/2007	NO	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35	LOW-NOX BURNER AND FLUE GAS RECIRCULATION	0.0350	BACT-PSD
COPPER MOUNTAIN POWER	CLARK,NV	5/14/2004	?	AUXILIARY BOILER	60	LOW NOX BURNER (WITH EITHER INTERNAL OR EXTERNAL FGR)	0.0350	UNKNOWN
HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	MONTGOMERY,AL	3/23/2004	?	BOILERS, NATURAL GAS (3)	50	NATURAL GAS ONLY; LOW NOX BURNERS	0.0350	BACT-PSD
HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	MONTGOMERY CO., AL	3/23/2004	?	(3) BOILERS	50	NATURAL GAS ONLY; LNB	0.0350	BACT-PSD
QUAD GRAPHICS OKC FAC	OKLAHOMA CO., OK	2/3/2004	?	BOILERS	27	LNB, CLEAN FUEL AND FGR	0.0350	BACT-PSD
COB ENERGY FACILITY, LLC	KLAMATH CO., OR	12/30/2003	?	(2) AUXILIARY BOILERS	80	LNB AND FGR	0.0350	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/21/2003	?	(2) BOILER	34	LNB, NATURAL GAS	0.0350	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEF I AND II)	ARLINGTON, AZ	11/6/2003	?	(2) AUXILIARY BOILERS	33	OPERATION LIMITED TO < 6,000 HR/YR	0.0350	BACT-PSD
MURRAY ENERGY FACILITY	MURRAY CO., GA	10/23/2002	NO	AUXILIARY BOILER	36	DRY LNB, FGR (< 6,000 HR/YR)	0.0350	BACT-PSD
HONDA MANUFACTURING OF ALABAMA, LLC	TALLADEGA CO., AL	10/18/2002	?	(3) BOILERS	30	LNB, CLEAN FUEL, GOOD COMBUSTION	0.0350	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON CO., AR	4/1/2002	?	AUXILIARY BOILER	33		0.0350	BACT-PSD
MARTINSBURG PLANT	BERKELEY CO., WV	8/30/2001	?	BOILER	54	LNB AND FGR	0.0350	BACT-PSD
MARTINSBURG PLANT	BERKELEY CO., WV	8/30/2001	?	(3) BOILERS	66	LNB AND FGR	0.0350	BACT-PSD
QUAD GRAPHICS OKC FACILITY	OKLAHOMA CO., OK	8/21/2001	?	BOILERS	63	LNB	0.0350	BACT-PSD
SWEC-FALLS TOWNSHIP	GLEN ALLEN, PA	8/7/2001	?	AUXILIARY BOILER	41	NATURAL GAS ONLY	0.0350	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	AUXILIARY BOILER	96	OPERATION LIMITED TO < 500 HR/YR	0.0350	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	AUXILIARY BOILER	25	LNB, FGR (< 1,000 HR/YR)	0.0350	LAER
MORTON INTERNATIONAL	WYOMING CO., NY	8/23/1995	?	STANDBY MID-SIZE BOILER	93	LIMIT OPERATION TO 500 HOURS PER YEAR	0.0350	RACT
STAFFORD RAILSTEEL CORPORATION	CRITTENDEN CO., AR	8/17/1993	?	VTD BOILER	47	FUEL SPEC: USE OF NATURAL GAS & LNB	0.0351	BACT-PSD
CENTRAL SOYA COMPANY INC.	HURON CO., OH	11/29/2001	?	BOILER	91	USE OF LNB	0.0352	SIP
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	AUXILIARY BOILER	21	DLN COMBUSTORS	0.0352	BACT-PSD
TOLEDO SUPPLIER PARK- PAINT SHOP	LUCAS,OH	5/3/2007	No	BOILER -2 NATURAL GAS	20	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.0353	
SITHE MYSTIC DEVELOPMENT LLC	SUFFOLK CO., MA	9/29/1999	?	AUXILIARY BOILER	96	SCR	0.0354	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	ONONDAGA CO., NY	12/10/1994	?	(3) UTILITY BOILERS	33	INDUCED FGR	0.0355	BACT-OTHER
DUKE ENERGY WYTHE, LLC	RALEIGH, NC	2/5/2004	NO	AUXILIARY BOILER	37	GCP	0.0355	BACT-PSD
VA POWER - POSSUM POINT	PRINCE WILLIAM CO., VA	11/18/2002	?	AUXILIARY BOILER	99	LNB AND LOW NOX FUEL	0.0360	BACT-OTHER
DART CONTAINER CORP OF PA	LANCASTER CO., PA	12/14/2001	YES	(2) CLEAVER BROOKS BOILERS	34	LNB	0.0360	NSPS
MCCLAIN ENERGY FACILITY	MCCLAIN CO., OK	10/25/2001	?	AUXILIARY BOILER	22	NATURAL GAS FUEL AND GOOD COMBUSTION CONTROL	0.0360	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	1/5/2001	?	(2) BOILERS	12	LNB	0.0360	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	1/5/2001	?	(2) BOILERS	13	LNB	0.0360	BACT-PSD
DARLING INTERNATIONAL	FRESNO CO., CA	12/30/1996	?	NEBRASKA BOILER MODEL NS-B-40	31	LNB, FGR	0.0360	LAER
SUNLAND REFINERY	CALIFORNIA	9/24/1992	?	(2) BOILERS	13	FGR/LNB	0.0360	BACT-OTHER
WPS - WESTON PLANT	MARATHON,WI	8/27/2004	?	NATURAL GAS FIRED BOILER	46	BURNER DESIGN, NATURAL GAS FUELED	0.0361	N/A
KLAMATH GENERATION, LLC	KLAMATH CO., OR	3/12/2003	?	AUXILIARY BOILER	59	NONE INDICATED	0.0363	BACT-PSD
CLOVIS ENERGY FACILITY	CURRY CO., NM	6/27/2002	?	(2) AUXILIARY BOILERS	33	CLEAN FUEL, GCP	0.0364	BACT-PSD
CON AGRA SOYBEAN PROCESSING CO.	POSEY CO., IN	8/14/1998	?	REFINERY & HYDROGEN PLANT REFORMER BOILERS	10	LNB AND FGR	0.0365	BACT-PSD
SITIX OF PHOENIX, INC.	MARICOPA CO., AZ	2/1/1996	?	BOILER	42	FGR	0.0369	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON CO., OH	1/18/2001	?	BOILER	47	NONE INDICATED	0.0369	BACT-PSD
SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH	SWEETWATER CO., WY	2/6/1998	?	BOILER	100	LNB SYSTEM	0.0380	LAER
NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	SKAGIT,WA	6/14/2006	?	BOILER, NATURAL GAS	4	GOOD COMBUSTION PRACTICE	0.0400	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	BOILER, NATURAL GAS (1)	40	LOW NOX BURNER; FGR.	0.0400	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	BOILER	40	LNB; FGR	0.0400	BACT-PSD

Appendix E: Table E-13
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	NO_x EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
J & L SPECIALTY STEEL, INC.	BEAVER CO., PA	1/13/2003	?	DRAP LINE BOILER	34	ULTRA LNB	0.0400	BACT-OTHER
GENOVA ARKANSAS I, LLC	WASHINGTON CO., AR	8/23/2002	?	AUXILIARY BOILER	33	LNB AND/OR FGR	0.0400	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	ASCENSION PARISH, LA	5/10/2000	?	C15/C16 COLUMN REBOILER FURNACE	21	LNB	0.0400	BACT-PSD
CABOT POWER CORPORATION	SUFFOLK CO., MA	5/7/2000	?	AUXILIARY BOILER	27	SCR, DLN COMBUSTOR	0.0400	LAER
VICKSBURG CHEMICAL COMPANY	MISSISSIPPI	10/27/1998	?	BOILER	99	LNB AND FGR	0.0420	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON,AR	2/17/2004	?	BOILER,PROCESS STEAM (2) SN-PBCDF-03 -04	32	LOW-NOX BURNERS WITHOUT FLUE GAS RECIRCULATION.	0.0476	BACT-PSD
CPV CUNNINGHAM CREEK	FLUVANNA CO., VA	9/6/2002	?	AUXILIARY BOILER	80	LNB AND GCP	0.0478	BACT-PSD
MCCLELLAN AFB, U.S. GOVERNMENT	SACRAMENTO CO., CA	10/29/1986	?	BOILER	62	LNB, FGR	0.0484	BACT-PSD
GILROY ENERGY CO.	CALIFORNIA	8/1/1985	?	(2) AUXILIARY BOILER	90	LNB	0.0489	BACT-PSD
FOLSOM PRISON	SACRAMENTO CO., CA	6/12/1986	?	(2) BOILER	48	FGR	0.0490	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	12/20/2002	?	AUXILIARY BOILER	68	DLN	0.0490	BACT-OTHER
ALLEGHENY ENERGY SUPPLY CO. LLC	ST. JOSEPH CO., IN	12/7/2001	?	AUXILIARY BOILER	21	LNB	0.0490	BACT-PSD
DUKE ENERGY, VIGO LLC	VIGO CO., IN	6/6/2001	?	(2) AUXILIARY BOILERS	46	GOOD COMBUSTION. LNB	0.0490	BACT-PSD
THUNDERBIRD POWER PLT	CLEVELAND CO., OK	5/17/2001	?	AUXILIARY BOILER	20	LNB	0.0490	BACT-PSD
MIRANT SUGAR CREEK, LLC	VIGO CO., IN	5/9/2001	?	(2) AUXILIARY BOILERS	35	LNB, GOOD COMBUSTION, NATURAL GAS	0.0490	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	TULSA CO., OK	10/1/1999	?	AUXILIARY BOILER	24	LNB	0.0490	BACT-PSD
GENPOWER EARLEYS, LLC	HERTFORD CO., NC	1/9/2002	?	AUXILIARY BOILER	83	LNB	0.0490	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	AUXILIARY BOILER	33	LNB	0.0500	BACT-PSD
FPL WEST COUNTY ENERGY CENTER	WEST PALM BEACH,FL	1/10/2007	NO	TWO 99.8 MMBTU/HR GAS-FUELED AUXILIARY BOILERS	100		0.0500	BACT-PSD
OHIO RIVER PLANT	PLEASANTS CO., WV	6/9/2004	NO	BOILER	39	LNB/FGR	0.0500	BACT-PSD
LAWRENCE ENERGY	LAWRENCE CO., OH	9/24/2002	?	BOILER	99	LNB	0.0500	BACT-PSD
BARTON SHOALS ENERGY	COLBERT CO., AL	7/12/2002	?	(2) AUXILIARY BOILERS	40	LNB	0.0500	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	AUXILIARY BOILER	33	LNB	0.0500	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK CO., IA	4/10/2002	?	AUXILIARY BOILER	68	NONE INDICATED	0.0500	BACT-PSD
WEBERS FALLS ENERGY FACILITY	MUSKOGEE CO., OK	10/22/2001	?	AUXILIARY BOILER	30	LNB (< 3,000 HR/YR)	0.0500	BACT-PSD
GENPOWER KELLEY LLC	WALKER CO., AL	1/12/2001	?	BOILER	83	LNB	0.0500	BACT-PSD
AMERICAN SODA, LLP, PARACHUTE FACILITY	GARFIELD CO., CO	5/6/1999	?	INDUSTRIAL BOILER	81	LOW NOX COMBUSTION SYSTEM	0.0500	BACT-PSD
AMERICAN SODA, LLP, PINEANCE FACILITY	RIO BLANCO CO., CO	5/6/1999	?	TEST MINE HOT WATER BOILER NO.2	51	LOW NOX COMBUSTION SYSTEM	0.0500	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	ASCENSION PARISH, LA	2/13/1998	?	BOILER NO. 1	95	LNB	0.0500	BACT-PSD
I/N KOTE	ST. JOSEPH CO., IN	11/20/1989	?	PACKAGE BOILER	71	FUEL SPEC: USE OF NATURAL GAS & FGR	0.0500	BACT-PSD
I/N TEK	INDIANA	10/15/1987	?	(2) BOILER	73	FGR, NOX SUPPRESSION & BURNER DESIGN	0.0500	BACT-PSD
NAVAL STATION TREASURE ISLAND	SOLANDO CO., CA	12/19/1986	?	STEAM BOILER	24	LNB, FGR	0.0500	OTHER
SCHERING CORPORATION	UNION CO., NJ	3/7/1996	?	BOILERS 4&5	94	LNB	0.0506	BACT-PSD
BMW MANUFACTURING CORP.	SPARTANBURG CO., SC	1/7/1994	?	(3) AUXILIARY BOILERS	60	LNB AND FGR	0.0508	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	NO	(2) HOT WATER BOILER	12	LNB	0.0513	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	NO	(2) PROCESS STEAM BOILER	28	LNB	0.0528	BACT-PSD
OHIO RIVER PLANT	PLEASANTS,WV	6/9/2004	?	BOILER, NATURAL GAS 39.00 MMBTU	39	LOW-NOX BURNERS/FLUE-GAS RECIRCULATION	0.0533	BACT-PSD
RINCON POWER PLANT	EFFINGHAM CO., GA	3/24/2003	?	AUXILIARY BOILER	83	NONE INDICATED	0.0550	BACT-OTHER
DEL MONTE FOODS, USA	CALIFORNIA	9/26/1990	?	JOHNSTON BOILER	21	JOHNSTON BURNER	0.0586	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	CCR STABILIZATION REBOILER	54	NONE INDICATED	0.0600	BACT-PSD
INDELK ENERGY SERVICES OF OTSEGO	ALLEGAN CO., MI	3/16/1993	?	BOILER	99	FGR	0.0600	BACT-OTHER
INTEL CORPORATION	ARIZONA	9/1/1996	?	(10) BOILERS	54	LNB	0.0611	BACT-PSD
AMTRAK	PENNSYLVANIA	10/12/1988	?	(2) BOILER	90	LNB	0.0652	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	AUXILIARY BOILER	27	LNB	0.0700	BACT-PSD
DOW CHEMICAL CO.	MICHIGAN	2/21/1989	?	(2) BOILER	40	FGR, LOW EXCESS AIR STAGED COMBUSTION	0.0700	BACT-PSD
WAUPACA FOUNDRY - PLANT 5	PERRY CO., IN	1/19/1996	?	BOILERS	94	LNB	0.0739	BACT-PSD
REDBUD POWER PLT	OKLAHOMA CO., OK	5/6/2002	?	AUXILIARY BOILER	93	LNB	0.0750	BACT-PSD
HULS AMERICA	MOBILE CO., AL	8/31/1990	?	(2) BOILERS	39	LNB	0.0750	BACT-PSD
QUALITECH STEEL CORP.	HENDRICKS CO., IN	10/31/1996	?	BOILERS	68	NONE INDICATED	0.0794	BACT-PSD
BADAMI DEVELOPMENT FACILITY	NORTH SLOPE BOROUGH,AK	8/19/2005	No	NATCO TEG REBOILER	1	CONVENTIONAL BURNER TECHNOLOGY	0.0800	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI,AR	7/22/2004	?	BOILERS	22	LOW NOX BURNERS	0.0800	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	BOILERS	22	LNB	0.0800	BACT-PSD
INDECK-ELWOOD, LLC	BUFFALO GROVE, IL	10/10/2003	?	BOILER	99	OPERATION LIMITED TO < 2,500 HR/YR	0.0800	BACT-PSD
ABBOTT LABORATORIES, STURGIS PLANT	ST. JOSEPH CO., MI	9/16/2003	?	BOILER	99	LNB AND FGR	0.0800	BACT-PSD
HENRY COUNTY POWER	HENRY CO., VA	11/21/2002	?	(2) AUXILIARY BOILER	40	LNB AND CLEAN FUEL	0.0800	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	LAWRENCE CO., IN	10/5/2001	?	AUXILIARY BOILER	35	CLEAN FUEL, LNB	0.0800	BACT-PSD
BLOUNT MEGAWATT FACILITY	BLOUNT CO., AL	2/5/2001	?	AUXILIARY BOILER	40	LNB	0.0800	BACT-PSD
ROCKPORT WORKS	INDIANA	2/13/1997	?	(2) BOILERS BH NO. 2	76	LNB	0.0800	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	BOILER, NO. 9	95	NONE INDICATED	0.0840	BACT-PSD
DOUGLAS AIRCRAFT CO.	CALIFORNIA	4/23/1987	?	(3) BOILER	34	FGR, OXYGEN TRIM	0.0846	BACT-PSD
JACKSON COUNTY POWER, LLC	JACKSON CO., OH	12/27/2001	?	AUXILIARY BOILER	76	LNB	0.0880	BACT-PSD
QUINCY SOYBEAN COMPANY OF ARKANSAS	PHILLIPS CO., AR	3/4/1997	?	COGENERATION/WASTE HEAT RECOVERY BOILER	68	LOW NOX COMBUSTORS	0.0926	BACT-PSD
CRESCENT CITY POWER	ORLEANS,LA	6/6/2005	No	FUEL GAS HEATERS (3)	19	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.0953	BACT-PSD
CALIFORNIA DEPT. OF CORRECTIONS	CALIFORNIA	12/18/1987	?	(2) BOILER	36	FGR	0.0954	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	TALLADEGA CO., AL	10/3/2001	?	AUXILIARY BOILER	30	LOW NOX COMBUSTION	0.0960	BACT-PSD
CHARTER STEEL	CUYAHOGA,OH	6/10/2004	?	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	29	LOW NOX BURNER	0.0979	BACT-PSD
MUSTANG ENERGY PROJECT	CANADIAN CO., OK	2/12/2002	?	AUXILIARY BOILER	31	GCP AND DESIGN	0.0980	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	AUXILIARY BOILERS	31	GCP AND DESIGN	0.0980	BACT-PSD
GENERAL ELECTRIC	LOWNDES CO., AL	10/14/1988	?	BOILER	99	LNB	0.0995	BACT-PSD
SHELL OFFSHORE, INC.	ALABAMA	10/25/1989	?	BOILER	48	LNB	0.0996	BACT-PSD
PANDA-ROSEMARY CORP.	NORTH CAROLINA	9/6/1989	?	(2) BOILER	81	LNB	0.0997	BACT-PSD
SOLAR GAS TURBINE COGEN.	ECTOR CO., TX	4/3/2000	?	AUXILIARY BOILER	54	NONE INDICATED	0.1000	BACT-PSD
BP CHERRY POINT REFINERY	WHATCOM,WA	4/20/2005	?	PROCESS HEATER IHT	13	ULTRA LOW NOX BURNERS	0.1000	BACT-PSD
DRESDEN ENERGY LLC	MUSKINGUM CO., OH	10/16/2001	?	BOILER	49	NONE INDICATED	0.1000	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CO., OK	8/16/2001	?	(2) AUXILIARY BOILERS	48	DRY LLNB, OPERATES IN PRE-MIX MODE	0.1000	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	AUXILIARY BOILER	28	LNB	0.1000	BACT-PSD
PROCTER & GAMBLE PAPER PRODUCTS COMPANY	WYOMING CO., PA	2/24/2000	?	(3) BOILERS	90	LNB	0.1000	BACT-PSD
BUCKNELL UNIVERSITY	UNION CO., PA	11/26/1997	?	HEAT RECOVERY BOILER	28	NONE INDICATED	0.1000	BACT-OTHER
TOYOTA MOTOR MANUFACTURING, USA, INC	SCOTT CO., KY	5/29/1997	?	BOILER	96	NONE INDICATED	0.1000	BACT-PSD
TOYOTA MOTOR CORPORATION SVCS OF N.A.	GIBSON CO., IN	8/9/1996	?	(6) BOILERS	58	LNB & FUEL SPEC: USE OF NATURAL GAS AS FUEL	0.1000	BACT-PSD
MID-GEORGIA COGEN.	HOUSTON CO., GA	4/3/1996	?	BOILER	60	DRY LNB WITH FGR	0.1000	BACT-PSD

Appendix E: Table E-13
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	NO_x EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
OVERHALL LAUNDRY SERVICE, INC.	WASHINGTON	5/12/1992	?	BOILER	12	LNB	0.1000	BACT-OTHER
TOYOTA MOTOR MANUFACTURING	SCOTT CO., KY	6/21/1991	?	BOILER	96	NONE INDICATED	0.1000	BACT-PSD
NORTHERN CONSOLIDATED POWER	PENNSYLVANIA	5/3/1991	?	AUXILIARY BOILER	100	NONE INDICATED	0.1000	NSPS
DOW CORNING CORP.	CARROLL CO., KY	1/7/1991	?	POWER BOILERS	97	NONE INDICATED	0.1000	BACT-PSD
KAISER ALUMINUM & CHEMICAL CORP.	OHIO	9/24/1986	?	BOILER	17	NONE INDICATED	0.1000	OTHER
INTERNATIONAL PAPER CO.	DALLAS CO., TX	2/4/1984	?	PACKAGE BOILER	15	AUTOMATIC O2 CONTROL	0.1000	BACT-PSD
BOEING COMMERCIAL AIRPLANE-FREDERKSN	WASHINGTON	4/2/1992	?	(2) BOILERS	26	LNB	0.1000	BACT-OTHER
LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	FREMONT CO., WY	4/3/1998	?	AUXILIARY BOILER	23	NONE INDICATED	0.1005	OTHER
GOODSPRINGS COMPRESSOR STATION	CLARK,NV	5/16/2006	No	COMMERCIAL/INSTITUTIONAL BOILER	4	GOOD COMBUSTION PRACTICE	0.1010	BACT-PSD
BAYTOWN CARBON BLACK PLANT	HARRIS CO., TX	12/31/2002	?	BACK-UP BOILER	13	NONE INDICATED	0.1045	BACT-OTHER
O.H. KRUSE GRAIN AND MILLING	CALIFORNIA	9/19/1996	?	BOILER USED AS A BACKUP	10	NONE INDICATED	0.1060	LAER
DUKE ENERGY DALE, LLC	DALE CO., AL	12/11/2001	?	AUXILIARY BOILER	35	LNB	0.1080	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	AUTAUGA CO., AL	10/23/2001	?	BOILER	31	LNB	0.1080	BACT-PSD
GORDONSVILLE ENERGY L. P.	VIRGINIA	7/30/1993	?	AUXILIARY BOILER	22	LNB	0.1091	NSPS
PSEG WATERFORD ENERGY LLC	WASHINGTON CO., OH	3/29/2001	?	AUXILIARY BOILER	93	GAS AS SOLE FUEL, LNB	0.1100	BACT-PSD
TEX-USS	TEXAS	4/16/1981	?	STEAM BOILER	99	LNB	0.1100	BACT-PSD
TEX-USS	TEXAS	4/16/1981	?	STEAM BOILER	99	LNB	0.1100	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX CO., VA	9/25/1992	?	AUXILIARY BOILER	60	LNB	0.1117	BACT-PSD
NISSAN NORTH AMERICA, INC.	MADISON CO., MS	4/2/2001	?	BOILER	35	LNB	0.1200	BACT-PSD
DUKE ENERGY HOT SPRINGS	HOT SPRINGS CO., AR	12/29/2000	?	(2) AUXILIARY BOILERS	44	LOW NOX COMBUSTER & PROPER OPERATION	0.1200	BACT-PSD
NORTHSTAR DEVELOPMENT PROJECT	ALASKA	2/5/1999	NO	WASTE HEAT RECOVERY UNIT 10	53	< 1,000 HR/YR	0.1200	BACT-OTHER
ROCKPORT WORKS	INDIANA	2/13/1997	?	(2) BOILERS BH NO. 2	76	LNB	0.1200	BACT-PSD
SUN REFINING & MARKETING CO.	OHIO	11/2/1987	?	BOILER	68	LNB	0.1200	OTHER
SHINTECH, INC.	TEXAS	1/5/1981	?	STEAM BOILER	55	LNB	0.1200	BACT-PSD
ATOFINA CHEMICALS INCORPORATED	JEFFERSON CO., TX	12/19/2002	NO	(2) STEAM BOILERS	16	LNB	0.1297	OTHER
GENERAL ELECTRIC CO.	INDIANA	9/17/1989	?	BOILER	93	STAGED COMBUSTION AIR & LOW EXCESS AIR	0.1330	BACT-PSD
CNG TRANSMISSION CORPORATION	WEST VIRGINIA	5/3/1993	?	WATER BOILER	10	NONE INDICATED	0.1373	BACT-PSD
MACSTEEL DIVISION	SEBASTIAN CO., AR	10/28/1993	?	BOILER	45	LNB	0.1400	BACT-PSD
PORT WASHINGTON GENERATING STATION	WASHINGTON,WI	10/13/2004	?	NATURAL GAS FIRED AUXILLIARY BOILER	97	COMBUSTION OPTIMIZATION (BASED ON CF DURING OZONE SEASON > 20%)	0.1411	N/A
REYNOLDS METALS CO.	ALABAMA	7/7/1989	?	MILL BOILER	29	LNB	0.1417	BACT-PSD
HARRISONBURG RESOURCE RECOVER FACILITY	HARRISONBURG, VA	3/24/2003	?	BOILER NO. 1	43	FGR WITH LNB, CEM SYSTEM, GCP	0.1428	BACT-OTHER
STANLEY FURNITURE	HENRY CO., VA	12/1/2002	?	KEWANEE BOILER	27	NONE INDICATED	0.1434	BACT-OTHER
R. R. DONNELLEY PRINTING COMPANY	CAMPBELL CO., VA	5/2/1994	?	BOILER	47	NONE INDICATED	0.1461	BACT-PSD
EXXON CO., USA	LINCOLN CO., WY	5/22/1984	?	(3) BOILER	26	DESIGN	0.1700	BACT-PSD
ARCHER DANIELS MIDLAND	PEORIA CO., IL	5/28/1982	?	BOILER	90	EQUIPMENT DESIGN	0.1700	BACT-PSD
ARKANSAS EASTMAN CO.	ARKANSAS	7/14/1987	?	BOILER #4	78	NONE INDICATED	0.1705	OTHER
CARGILL INC - SIOUX CITY	WOODBURY CO., IA	6/1/1998	?	BACKUP BOILER	77	NONE INDICATED	0.1766	OTHER
INTERNATIONAL FLAVORS AND FRAGRANCES	MONMOUTH CO., NJ	6/9/1995	?	BOILER	96	NONE INDICATED	0.1800	RACT
NUCOR STEEL	MONTGOMERY CO., IN	11/30/1993	?	VACUUM DEGASSER BOILER	34	LNB, STAGED COMBUSTION	0.1900	BACT-PSD
INDECK-YERKES ENERGY SERVICES	ERIE CO., NY	6/24/1992	?	AUXILIARY BOILER	99	NONE INDICATED	0.2000	BACT-OTHER
DOW CORNING CORP.	CARROLL CO., KY	1/7/1991	?	POWER BOILERS	97	NONE INDICATED	0.2000	BACT-PSD
CHEVRON USA, INC.	WYOMING	5/28/1980	?	(6) BOILER	94	DESIGN	0.2000	BACT-PSD
AMOCO PRODUCTION CO.	WYOMING	12/20/1979	?	(2) BOILER	66	DESIGN	0.2000	BACT-PSD
CIG	SWEETWATER CO., WY	8/25/1976	?	(2) BOILER	48	DESIGN	0.2000	OTHER
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	RANSOM CO., ND	7/9/1998	?	NEBRASKA BOILER	28	NONE INDICATED	0.2071	BACT-PSD
PPG INDUSTRIES, INC.	TEXAS	5/27/1981	?	(2) BOILER	21	COMBUSTION CONTROL	0.2294	BACT-PSD
WALLULA POWER PLANT	WALLA WALLA CO., WA	1/3/2003	?	AUXILIARY BOILER	55	LNB PLUS FGR (<4,000 HR/YR)	0.2300	BACT-OTHER
WYCON CHEMICALS	WYOMING	7/27/1984	?	UREA PLT BOILER	26	NONE INDICATED	0.2300	OTHER
MICHELIN NORTH AMERICA, INC.	LEXINGTON CO., SC	8/14/1996	?	(2) BOILERS	95	LNB AND FGR	0.2526	BACT-PSD
QUAD/GRAPHICS, INC.	BERKELEY CO., WV	9/14/1995	?	(2) BOILERS	43	FUEL SPEC	0.3163	BACT-PSD
KAMINE/BESICORP CORNING L.P.	NEW YORK	11/5/1992	?	(3) AUXILIARY BOILERS	34	LNB, FGR	0.3200	BACT-OTHER
HYUNDAI MOTOR MANUFACTURING ALABAMA, LLC	MONTGOMERY,AL	11/22/2004	?	BOILER, NATURAL GAS (2)	25	LOW NOX BURNERS	0.3500	
WELLTON MOHAWK GENERATINGSTATION	YUMA,AZ	12/1/2004	?	AUXILIARY BOILER	38	LOW NOX BURNERS	0.3700	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	NO	AUXILIARY BOILER	38	OPERATION LIMITED TO < 480 HR/YR	0.3700	BACT-OTHER
ROCHE VITAMINS	WARREN CO., NJ	2/5/1999	?	BOILER 1	84	NONE INDICATED	0.4005	BACT-PSD
PORT HUDSON OPERATIONS	E. BATON ROUGE PARISH, LA	1/25/2002	?	POWER BOILER NO. 2	66	LNB	0.9365	BACT-OTHER

Appendix E: Table E-14
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	CO EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
UNIVERSITY OF CALIFORNIA IRVINE MEDICAL CENTER	ORANGE CO., CA	1/16/1992	?	ZURN/KEYSTONE WATERTUBE BOILER	49	SIX ALZETA CORPORATION CERAMIC FIBER RADIANT LNB	0.0068	BACT-PSD
PRO TEC COATING COMPANY	PUTNAM CO., OH	2/15/2001	?	(4) BOILERS	21	NONE INDICATED	0.0110	SIP
STAFFORD RAILSTEEL CORPORATION	CRITTENDEN CO., AR	8/17/1993	?	VTD BOILER	47	FUEL SPEC: USE OF NATURAL GAS & LNB	0.0151	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	12/20/2002	?	AUXILIARY BOILER	68	CATALYTIC OXIDATION	0.0164	BACT-OTHER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	AUXILIARY BOILER	99	NATURAL GAS ONLY	0.0200	LAER
KAISER ALUMINUM & CHEMICAL CORP.	OHIO	9/24/1986	?	BOILER	17	NONE INDICATED	0.0200	OTHER
INTERNATIONAL PAPER CO.	DALLAS CO., TX	2/4/1984	?	PACKAGE BOILER	15	NONE INDICATED	0.0300	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/30/1993	?	VACUUM DEGASSER BOILER	34	NONE INDICATED	0.0330	BACT-PSD
PANDA-ROSEMARY CORP.	NORTH CAROLINA	9/6/1989	?	(2) BOILER	81	COMBUSTION CONTROL	0.0332	BACT-PSD
CNG TRANSMISSION CORPORATION	WEST VIRGINIA	5/3/1993	?	WATER BOILER	10	NONE INDICATED	0.0343	BACT-PSD
KLAMATH GENERATION, LLC	KLAMATH CO., OR	3/12/2003	?	AUXILIARY BOILER	59	NONE INDICATED	0.0350	BACT-PSD
ROCHE VITAMINS	WARREN CO., NJ	2/5/1999	?	BOILER 1	84	NONE INDICATED	0.0355	BACT-PSD
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	RANSOM CO., ND	7/9/1998	?	NEBRASKA BOILER	28	NONE INDICATED	0.0357	BACT-PSD
R. R. DONNELLEY PRINTING COMPANY	CAMPBELL CO., VA	5/2/1994	?	BOILER	47	NONE INDICATED	0.0360	BACT-PSD
CPV WARREN	WARREN,VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 2	97	CEM SYSTEM	0.0360	N/A
CPV WARREN	WARREN,VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 3	62	CEM SYSTEM	0.0360	N/A
HARRAH'S OPERATING COMPANY, INC.	CLARK,NV	1/4/2007	NO	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35	GOOD COMBUSTION DESIGN	0.0360	BACT-PSD
CAITHNES BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	?	AUXILIARY BOILER	29	GOOD COMBUSTION PRACTICES	0.0360	BACT-PSD
WPS - WESTON PLANT	MARATHON,WI	8/27/2004	?	NATURAL GAS FIRED BOILER	46	BOILER DESIGN	0.0361	N/A
MERCK - RAHWAY PLANT	UNION CO., NJ	1/14/1997	?	(3) BOILERS	100	NONE INDICATED	0.0362	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	AUXILIARY BOILER	21	ADEQUATE FUEL RESIDENCE TIME & PROPER COMB. TEMP	0.0362	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE CO., OH	12/13/2001	?	(2) BOILER	37	NONE INDICATED	0.0369	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE,OH	12/28/2004	?	BOILERS (2)	31		0.0369	BACT-PSD
COB ENERGY FACILITY, LLC	KLAMATH CO., OR	12/30/2003	?	(2) AUXILIARY BOILERS	80	GOOD COMBUSTION	0.0370	BACT-PSD
MURRAY ENERGY FACILITY	MURRAY CO., GA	10/23/2002	NO	AUXILIARY BOILER	36	GCP (< 6,000 HR/YR)	0.0370	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	GRAYS HARBOR CO., WA	10/23/2001	?	AUXILIARY BOILER	29	NONE INDICATED	0.0370	BACT-PSD
SWEC-FALLS TOWNSHIP	GLEN ALLEN, PA	8/7/2001	?	AUXILIARY BOILER	41	NATURAL GAS ONLY	0.0370	BACT-PSD
LACORR PACKAGING	LOS ANGELES CO., CA	7/12/2000	?	CLEAVER BROOKS MODEL CB-LE 500 BOILER	21	NONE INDICATED	0.0370	LAER
LIBERTY CONTAINER CO	LOS ANGELES CO., CA	3/17/2000	?	CLEAVER BROOKS CB (LE) 700-400	16	NONE INDICATED	0.0370	LAER
NATION WIDE BOILER	ALAMEDA CO., CA	3/15/2000	?	PORTABLE BOILER	29	GCP	0.0370	LAER
SANTA MONICA - UCLA MEDICAL CENTER	LOS ANGELES CO., CA	1/28/2000	?	CLEAVER BROOKS MODEL CE (LE) 200-400 FIRE-TUBE BOILER	16	FGR	0.0370	LAER
CHILDREN'S HOSPITAL LOS ANGELES	LOS ANGELES CO., CA	12/2/1999	?	BOILER	34	GCP	0.0370	LAER
CHILDREN'S HOSPITAL LOS ANGELES	LOS ANGELES CO., CA	12/2/1999	?	(2) BOILERS	24	GCP	0.0370	LAER
COCA COLA	LOS ANGELES CO., CA	11/23/1999	?	SCOTCH MARINE CUSTOM FIRE-TUBE BOILER	32	GCP	0.0370	BACT-PSD
ARKANSAS EASTMAN CO.	ARKANSAS	7/14/1987	?	BOILER #4	78	NONE INDICATED	0.0372	OTHER
INDECK-YERKES ENERGY SERVICES	ERIE CO., NY	6/24/1992	?	AUXILIARY BOILER	99	NONE INDICATED	0.0380	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	ONONDAGA CO., NY	12/10/1994	?	(3) UTILITY BOILERS	33	NONE INDICATED	0.0382	BACT-OTHER
THYSSENKRUPP STEEL AND STAINLESS USA, LLC	MOBILE,AL	8/17/2007	NO	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	65		0.0400	BACT-PSD
GENOVA ARKANSAS I, LLC	WASHINGTON CO., AR	8/23/2002	?	AUXILIARY BOILER	33	GCP	0.0400	BACT-PSD
MID-GEORGIA COGEN.	HOUSTON CO., GA	4/3/1996	?	BOILER	60	COMPLETE COMBUSTION	0.0500	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	ASCENSION PARISH, LA	2/13/1998	?	BOILER NO. 1	95	GOOD DESIGN, PROPER OPER. PRACTICES & 2% EXCESS O2	0.0600	BACT-PSD
NUCOR DECATUR LLC	MORGAN,AL	6/12/2007	NO	VACUUM DEGASSER BOILER	95		0.0610	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/21/2003	?	(2) BOILER	34	GCP, NATURAL GAS	0.0610	BACT-PSD
QUAD GRAPHICS OKC FACILITY	OKLAHOMA CO., OK	8/21/2001	?	BOILERS	63	GOOD COMBUSTION/MAINTENANCE	0.0699	BACT-PSD
REDBUD POWER PLT	OKLAHOMA CO., OK	5/6/2002	?	AUXILIARY BOILER	93	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.0700	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN,IA	6/29/2007	NO	NATURAL GAS BOILER (292.5 MMBTU/H)	293	ULNB WITH FGR AND GOOD COMBUSTION PRACTICES	0.0720	BACT-PSD
HENRY COUNTY POWER	HENRY CO., VA	11/21/2002	?	(2) AUXILIARY BOILER	40	GOOD COMBUSTION AND DESIGN, CLEAN FUEL	0.0725	BACT-PSD
HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	AUXILIARY BOILER	49	GCP	0.0730	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	TALLADEGA CO., AL	10/3/2001	?	AUXILIARY BOILER	30	EFFICIENT COMBUSTION	0.0730	BACT-PSD
BUMBLE BEE SEAFOODS, INC.	LOS ANGELES CO., CA	3/10/2000	?	SUPERIOR MOHAWK MODEL 4X-2007-S150 FIRE TUBE BOILER	16	NONE INDICATED	0.0740	LAER
HI-COUNTRY	RIVERSIDE CO., CA	12/16/1999	YES	FIRE TUBE BOILER	21	GCP	0.0740	LAER
CON AGRA SOYBEAN PROCESSING CO.	POSEY CO., IN	8/14/1998	?	REFINERY & HYDROGEN PLANT REFORMER BOILERS	10	COMBUSTION CONTROL	0.0740	BACT-PSD
SCHERING CORPORATION	UNION CO., NJ	3/7/1996	?	BOILERS 4&5	94	NONE INDICATED	0.0774	BACT-PSD
MINNESOTA STEEL INDUSTRIES, LLC	ITASCA, MN	9/7/2007	NO	SMALL BOILERS & HEATERS(<100 MMBTU/H)	99		0.0800	BACT-PSD
PROGRESS BARTOW POWER PLANT	PINELLAS, FL	1/26/2007	NO	ONE GASEOUS-FUELED 99 MMTU/HR AUXILIARY BOILER	99		0.0800	BACT-PSD
FPL WEST COUNTY ENERGY CENTER	WEST PALM BEACH,FL	1/10/2007	NO	TWO 99.8 MMBTU/HR GAS-FUELED AUXILIARY BOILERS	100		0.0800	BACT-PSD
CRESCENT CITY POWER	ORLEANS,LA	6/6/2005	?	FUEL GAS HEATERS (3)	19	GOOD COMBUSTION PRACTICES	0.0800	BACT-PSD
WELLTON MOHAWK GENERATINGSTATION	YUMA,AZ	12/1/2004	?	AUXILIARY BOILER	38		0.0800	BACT-PSD
OHIO RIVER PLANT	PLEASANTS,WV	6/9/2004	?	BOILER, NATURAL GAS 39.00 MMBTU	44		0.0800	BACT-PSD
COPPER MOUNTAIN POWER	CLARK,NV	5/14/2004	?	AUXILIARY BOILER	60	EFF. COMB. DESIGN, 10:1TURNDOWN CAPABILITY & LNB	0.0800	LAER
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	NO	AUXILIARY BOILER	38	OPERATION LIMITED TO < 480 HR/YR	0.0800	BACT-OTHER
BLOUNT MEGAWATT FACILITY	BLOUNT CO., AL	2/5/2001	?	AUXILIARY BOILER	40	GCP	0.0800	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	ASCENSION PARISH, LA	5/10/2000	?	C15/C16 COLUMN REBOILER FURNACE	21	GCP AND ENGINEERING DESIGN CLEAN BURNING FUEL	0.0800	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	AUXILIARY BOILER	96	OPERATION LIMITED TO < 500 HR/YR	0.0800	BACT-PSD
PORT WASHINGTON GENERATING STATION	WASHINGTON,WI	10/13/2004	?	NATURAL GAS FIRED AUXILLIARY BOILER	97	NATURAL GAS FUEL, GOOD COMBUSTION PRACTICES	0.0800	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	SUFFOLK CO., MA	9/29/1999	?	AUXILIARY BOILER	96	OXIDATION CATALYST	0.0802	BACT-PSD
CPV CUNNINGHAM CREEK	FLUVANNA CO., VA	9/6/2002	?	AUXILIARY BOILER	80	GCP	0.0803	BACT-PSD
LA PORTE POLYPROPYLENE PLANT	HARRIS CO., TX	11/5/2001	NO	PACKAGE BOILER BO-4	60	NONE INDICATED	0.0807	OTHER
GORDONSVILLE ENERGY L. P.	VIRGINIA	7/30/1993	?	AUXILIARY BOILER	22	GCP	0.0818	NSPS
BARTON SHOALS ENERGY	COLBERT CO., AL	7/12/2002	?	(2) AUXILIARY BOILERS	40	GCP	0.0820	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	AUXILIARY BOILER	33	GCP	0.0820	BACT-PSD
MUSTANG ENERGY PROJECT	CANADIAN CO., OK	2/12/2002	?	AUXILIARY BOILER	31	GCP AND DESIGN	0.0820	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	AUXILIARY BOILERS	31	GCP AND DESIGN	0.0820	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	ST. JOSEPH CO., IN	12/7/2001	?	AUXILIARY BOILER	21	GCP	0.0820	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	LAWRENCE CO., IN	10/5/2001	?	AUXILIARY BOILER	35	CLEAN FUEL, GCP	0.0820	BACT-PSD
DUKE ENERGY, VIGO LLC	VIGO CO., IN	6/6/2001	?	(2) AUXILIARY BOILERS	46	GOOD COMBUSTION	0.0820	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	TULSA CO., OK	10/1/1999	?	AUXILIARY BOILER	24	BOILER DESIGN & GOOD OPERATING PRACTICES	0.0820	BACT-PSD

Appendix E: Table E-14
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	CO EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
J & L SPECIALTY STEEL, INC.	BEAVER CO., PA	1/13/2003	?	DRAP LINE BOILER	34	NONE INDICATED	0.0821	BACT-OTHER
CHARTER STEEL	CUYAHOGA,OH	6/10/2004	?	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	29		0.0822	BACT-PSD
SOLAR GAS TURBINE COGEN.	ECTOR CO., TX	4/3/2000	?	AUXILIARY BOILER	54	NONE INDICATED	0.0824	NSPS
HARRISONBURG RESOURCE RECOVER FACILITY	HARRISONBURG, VA	3/24/2003	?	BOILER NO. 1	43	CEM SYSTEM AND GCP	0.0824	NSPS
GENPOWER EARLEYS, LLC	HERTFORD CO., NC	1/9/2002	?	AUXILIARY BOILER	83	GCP AND DESIGN	0.0824	BACT-PSD
BAYTOWN CARBON BLACK PLANT	HARRIS CO., TX	12/31/2002	?	BACK-UP BOILER	13	NONE INDICATED	0.0828	BACT-OTHER
GOODSPRINGS COMPRESSOR STATION	CLARK,NV	5/16/2006	?	COMMERCIAL/INSTITUTIONAL BOILER	4	GOOD COMBUSTION PRACTICE	0.0830	BACT-PSD
WALLULA POWER PLANT	WALLA WALLA CO., WA	1/3/2003	?	AUXILIARY BOILER	55	<4,000 HR/YR	0.0830	BACT-OTHER
STANLEY FURNITURE	HENRY CO., VA	12/1/2002	?	KEWANEE BOILER	27	NONE INDICATED	0.0830	BACT-OTHER
GORDONSVILLE ENERGY L.P.	FAIRFAX CO., VA	9/25/1992	?	AUXILIARY BOILER	60	GCP	0.0833	BACT-PSD
TOLEDO SUPPLIER PARK- PAINT SHOP	LUCAS,OH	5/3/2007	NO	BOILER -2 NATURAL GAS	20		0.0833	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	BOILER, NATURAL GAS (1)	40	GOOD COMBUSTION.	0.0840	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	BOILER	40	GOOD COMBUSTION	0.0840	BACT-PSD
HONDA MANUFACTURING OF ALABAMA, LLC	TALLADEGA CO., AL	10/18/2002	?	(3) BOILERS	30	CLEAN FUEL, GCP	0.0840	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK CO., IA	4/10/2002	?	AUXILIARY BOILER	68	NONE INDICATED	0.0840	BACT-OTHER
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CO., OK	8/16/2001	?	(2) AUXILIARY BOILERS	48	COMBUSTION CONTROL	0.0840	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	AUXILIARY BOILER	28	GOOD OPERATING PRACTICES AND DESIGN	0.0840	BACT-PSD
LAWRENCE ENERGY	LAWRENCE CO., OH	9/24/2002	?	BOILER	99	NONE INDICATED	0.0840	BACT-PSD
DRESDEN ENERGY LLC	MUSKINGUM CO., OH	10/16/2001	?	BOILER	49	NONE INDICATED	0.0841	BACT-PSD
ATOFINA CHEMICALS INCORPORATED	JEFFERSON CO., TX	12/19/2002	NO	(2) STEAM BOILERS	16	NONE INDICATED	0.0842	OTHER
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	AUXILIARY BOILER	33	GCP	0.0848	BACT-PSD
WEBERS FALLS ENERGY FACILITY	MUSKOGEE CO., OK	10/22/2001	?	AUXILIARY BOILER	30	BOILER DESIGN & GOOD OPER. PRACTICE (< 3,000 HR/YR)	0.0850	BACT-PSD
GENPOWER KELLEY LLC	WALKER CO., AL	1/12/2001	?	BOILER	83	EFFICIENT COMBUSTION	0.0850	BACT-PSD
DARLING INTERNATIONAL	FRESNO CO., CA	12/30/1996	?	NEBRASKA BOILER MODEL NS-B-40	31	GOOD COMBUSTION	0.0890	LAER
HYUNDAI MOTOR MANUFACTURING OF ALABAMA,LLC	MONTGOMERY,AL	3/23/2004	?	BOILERS, NATURAL GAS (3)	50	CLEAN FUEL	0.0900	BACT-PSD
OHIO RIVER PLANT	PLEASANTS CO., WV	6/9/2004	NO	BOILER	39	NONE INDICATED	0.0900	BACT-PSD
HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	MONTGOMERY CO., AL	3/23/2004	?	(3) BOILERS	50	CLEAN FUEL	0.0900	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	BOILER, NO. 9	95	NONE INDICATED	0.0900	BACT-PSD
AMERICAN SODA, LLP, PARACHUTE FACILITY	GARFIELD CO., CO	5/6/1999	?	INDUSTRIAL BOILER	81	GOOD COMBUSTION MANAGEMENT	0.0900	BACT-PSD
AMERICAN SODA, LLP, PINEANCE FACILITY	RIO BLANCO CO., CO	5/6/1999	?	TEST MINE HOT WATER BOILER NO.2	51	GOOD COMBUSTION	0.0900	BACT-PSD
JACKSON COUNTY POWER, LLC	JACKSON CO., OH	12/27/2001	?	AUXILIARY BOILER	76	NONE INDICATED	0.0903	BACT-PSD
RINCON POWER PLANT	EFFINGHAM CO., GA	3/24/2003	?	AUXILIARY BOILER	83	NONE INDICATED	0.0930	BACT-OTHER
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	AUXILIARY STEAM BOILER	80	CLEAN BURNING FUEL AND EFFICIENT COMBUSTION	0.0980	BACT-PSD
FREMONT ENERGY CENTER, LLC	SANDUSKY CO., OH	8/9/2001	?	AUXILIARY BOILER	80	NONE INDICATED	0.0980	BACT-PSD
INDECK-ELWOOD, LLC	BUFFALO GROVE, IL	10/10/2003		BOILER	99	OPERATION LIMITED TO < 2,500 HR/YR	0.1000	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	CCR STABILIZATION REBOILER	54	NONE INDICATED	0.1000	BACT-PSD
BUCKNELL UNIVERSITY	UNION CO., PA	11/26/1997	?	HEAT RECOVERY BOILER	28	NONE INDICATED	0.1000	BACT-OTHER
CENTRAL SOYA COMPANY INC.	HURON CO., OH	11/29/2001	?	BOILER	91	NONE INDICATED	0.1338	SIP
DUKE ENERGY WYTHE, LLC	RALEIGH, NC	2/5/2004	NO	AUXILIARY BOILER	37	NONE INDICATED	0.1339	BACT-PSD
DUKE ENERGY DALE, LLC	DALE CO., AL	12/11/2001	?	AUXILIARY BOILER	35	GOOD COMBUSTION	0.1350	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	AUTAUGA CO., AL	10/23/2001	?	BOILER	31	EFFICIENT COMBUSTION	0.1350	BACT-PSD
PSEG WATERFORD ENERGY LLC	WASHINGTON CO., OH	3/29/2001	?	AUXILIARY BOILER	93	NONE INDICATED	0.1350	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON CO., OH	1/18/2001	?	BOILER	47	NONE INDICATED	0.1421	BACT-PSD
VENTURA COASTAL CORP.	CALIFORNIA	11/17/1988	?	CLEAVER-BROOKS MODEL CB-400 BOILER	27	NONE INDICATED	0.1482	OTHER
CLOVIS ENERGY FACILITY	CURRY CO., NM	6/27/2002	?	(2) AUXILIARY BOILERS	33	DRY LOW NOX (DLN) TECHNOLOGY, GCP	0.1485	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	AUXILIARY BOILER	27	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.1490	BACT-PSD
DEMING ENERGY FACILITY	LUNA CO., NM	12/29/2000	?	AUXILIARY BOILER	44	GOOD COMBUSTION CONTROL, NATURAL GAS COMBUSTION	0.1497	BACT-PSD
BADAMI DEVELOPMENT FACILITY	NORTH SLOPE BOROUGH,AK	8/19/2005	?	NATCO TEG REBOILER	1	GOOD OPERATIONAL PRACTICES	0.1500	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEF I AND II)	ARLINGTON, AZ	11/6/2003	?	(2) AUXILIARY BOILERS	33	OPERATION LIMITED TO < 6,000 HR/YR	0.1500	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON CO., AR	4/1/2002	?	AUXILIARY BOILER	33	GOOD OPERATING PRACTICE	0.1500	BACT-PSD
DUKE ENERGY HOT SPRINGS	HOT SPRINGS CO., AR	12/29/2000	?	(2) AUXILIARY BOILERS	44	PROPER COMBUSTION PROCEDURES	0.1500	BACT-PSD
CABOT POWER CORPORATION	SUFFOLK CO., MA	5/7/2000	?	AUXILIARY BOILER	27	OXIDATION CATALYST	0.1500	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	AUXILIARY BOILER	25	OPERATION LIMITED TO < 1,000 HR/YR	0.1500	BACT-PSD
INDELK ENERGY SERVICES OF OTSEGO	ALLEGAN CO., MI	3/16/1993	?	BOILER	99	COMBUSTION CONTROL	0.1500	BACT-OTHER
VA POWER - POSSUM POINT	PRINCE WILLIAM CO., VA	11/18/2002	?	AUXILIARY BOILER	99	GCP	0.1505	BACT-OTHER
QUINCY SOYBEAN COMPANY OF ARKANSAS	PHILLIPS CO., AR	3/4/1997	?	COGENERATION/WASTE HEAT RECOVERY BOILER	68	GCP	0.1559	BACT-PSD
PROCTER & GAMBLE PAPER PRODUCTS COMPANY	WYOMING CO., PA	2/24/2000	?	(3) BOILERS	90	LNB	0.1730	BACT-PSD
COTTAGE HEALTH CARE - PUEBLO STREET	SANTA BARBARA,CA	5/16/2006	?	BOILER: 5 TO < 33.5 MMBTU/H	25	ULTRA-LOW NOX BURNER	0.1845	BACT-PSD
GENENTECH, INC.	SAN MATEO,CA	9/27/2005	?	BOILER:>= 50 MMBTU/H	97	ULTRA LOW NOX BURNERS: NATCOM P-97-LOG-35-2127	0.1845	
WAUPACA FOUNDRY - PLANT 5	PERRY CO., IN	1/19/1996	?	BOILERS	94	LNB	0.2045	BACT-PSD
BP CHERRY POINT REFINERY	WHATCOM,WA	4/20/2005	?	PROCESS HEATER IHT	13	GOOD COMBUSTION PRACTICES	0.2583	BACT-PSD
DART CONTAINER CORP OF PA	LANCASTER CO., PA	12/14/2001	YES	(2) CLEAVER BROOKS BOILERS	34	GCP	0.3000	BACT-OTHER
KAL KAN FOODS, INC.	LOS ANGELES CO., CA	7/24/1990	?	COEN DAF LOW NOX WATER-TUBE BOILER	79	GCP	0.3000	LAER
MCCLAIN ENERGY FACILITY	MCCLAIN CO., OK	10/25/2001	?	AUXILIARY BOILER	22	USE OF NATURAL GAS FUEL	0.3700	BACT-PSD
PORT HUDSON OPERATIONS	E. BATON ROUGE PARISH, LA	1/25/2002	?	POWER BOILER NO. 2	66	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION	0.5618	BACT-PSD
MIRANT SUGAR CREEK, LLC	VIGO CO., IN	5/9/2001	?	(2) AUXILIARY BOILERS	35	GOOD COMBUSTION	0.8240	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI,AR	7/22/2004	?	BOILERS	22	GOOD COMBUSTION PRACTICE	0.8400	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	BOILERS	22	GCP	0.8400	BACT-PSD

Appendix E: Table E-15
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 MMBtu/hr)
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	AUXILIARY BOILER	99	NATURAL GAS ONLY (< 900 HR/YR)	0.002	LAER
INTERNATIONAL PAPER CO.	DALLAS CO., TX	2/4/1984	NO	PACKAGE BOILER	15	NONE INDICATED	0.002	BACT-PSD
ROCHE VITAMINS	WARREN CO., NJ	2/5/1999	YES	EMERGENCY GENERATOR BOILER	84	EMERGENCY GENERATING UNIT < 500 HR/YR	0.002	BACT-PSD
NUCOR STEEL	CRAWFORDSVILLE, IN	11/21/2003	?	(2) COLD MILL BOILERS	34	COMPLIANCE BY USING NATURAL GAS	0.003	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS, NC	9/6/1989	YES	(2) BOILER	81	COMBUSTION CONTROL	0.003	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/30/1993	NO	VACUUM DEGASSER BOILER	34	NONE INDICATED	0.003	BACT-PSD
CNG TRANSMISSION CORPORATION	WEST VIRGINIA	5/3/1993	NO	WATER BOILER	10	NONE INDICATED	0.003	BACT-PSD
BMW MANUFACTURING CORP.	SPARTANBURG CO., SC	1/7/1994	?	(3) AUXILIARY BOILERS	60	NONE INDICATED	0.003	LAER
FAIRLESS WORKS ENERGY CENTER (FMR. SWEC-FALLS TOWNSHIP)	GLEN ALLEN, PA	8/7/2001	YES	AUXILIARY BOILER	41	NATURAL GAS ONLY	0.003	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	NO	AUXILIARY BOILER	38	OPERATION LIMITED TO < 480 HR/YR	0.003	BACT-OTHER
MERCK - RAHWAY PLANT	UNION CO., NJ	1/14/1997	YES	(3) BOILERS	100	NONE INDICATED	0.003	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	ONONDAGA CO., NY	12/10/1994	?	(3) UTILITY BOILERS	33	NONE INDICATED	0.003	BACT-OTHER
STANLEY FURNITURE	HENRY CO., VA	12/1/2002	?	KEWANEE BOILER	27	NONE INDICATED	0.004	BACT-OTHER
ARKANSAS EASTMAN CO.	ARKANSAS	7/14/1987	?	BOILER #4	78	NONE INDICATED	0.004	OTHER
RINCON POWER PLANT	EFFINGHAM CO., GA	3/24/2003	?	AUXILIARY BOILER	83	OPERATION LIMITED TO < 1,000 HR/YR	0.004	BACT-OTHER
TENASKA TALLADEGA GENERATING STATION	TALLADEGA CO., AL	10/3/2001	?	AUXILIARY BOILER	30	EFFICIENT COMBUSTION (< 1,000 HR/YR)	0.004	BACT-PSD
VA POWER - POSSUM POINT	PRINCE WILLIAM CO., VA	11/18/2002	?	(2) AUXILIARY BOILER	99	GCP	0.004	BACT-OTHER
STAFFORD RAILSTEEL CORPORATION	CRITTENDEN CO., AR	8/17/1993	NO	VTD BOILER	47	FUEL SPEC: USE OF NATURAL GAS	0.004	OTHER
HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	AUXILIARY BOILER	49	GCP	0.005	BACT-PSD
THUNDERBIRD POWER PLT	CLEVELAND CO., OK	5/17/2001	?	AUXILIARY BOILER	20	NONE INDICATED	0.005	BACT-PSD
MID-GEORGIA COGEN.	HOUSTON CO., GA	4/3/1996	?	BOILER	60	COMPLETE COMBUSTION	0.005	BACT-PSD
KAISER ALUMINUM & CHEMICAL CORP.	OHIO	9/24/1986	NO	BOILER	17	NONE INDICATED	0.005	OTHER
CPV CUNNINGHAM CREEK	FLUVANNA CO., VA	9/6/2002	?	AUXILIARY BOILER	80	GCP	0.005	BACT-PSD
PRO TEC COATING COMPANY	LEIPSIC, OH	6/20/2001	NO	(4) HOT WATER BOILERS	21	NONE INDICATED	0.005	SIP
HARRISONBURG RESOURCE RECOVER FACILITY	HARRISONBURG, VA	3/24/2003	?	BOILER NO. 1	43	GCP	0.005	NSPS
SOLAR GAS TURBINE COGEN.	ECTOR CO., TX	4/3/2000	?	AUXILIARY BOILER	54	OPERATION LIMITED TO < 175 HR/YR	0.005	NSPS
EMERY GENERATING STATION	CERRO GORDO CO., IA	12/20/2002	?	AUXILIARY BOILER	68	CATALYTIC OXIDATION (OPER < 6,000 HR/YR)	0.005	BACT-OTHER
BARTON SHOALS ENERGY	COLBERT CO., AL	7/12/2002	?	(2) AUXILIARY BOILERS	40	GCP	0.005	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	ST. JOSEPH CO., IN	12/7/2001	?	AUXILIARY BOILER	21	GCP	0.005	BACT-PSD
DUKE ENERGY, VIGO LLC	VIGO CO., IN	6/6/2001	?	(2) AUXILIARY BOILERS	46	GOOD COMBUSTION (< 500 HR/YR)	0.005	BACT-PSD
MIRANT SUGAR CREEK, LLC	VIGO CO., IN	5/9/2001	?	(2) AUXILIARY BOILERS	35	GOOD COMBUSTION (< 5,000 HR/YR)	0.005	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	TULSA CO., OK	10/1/1999	?	AUXILIARY BOILER	24	BOILER DESIGN / GOOD OPERATING PRACTICES	0.005	BACT-PSD
GENPOWER EARLEYS, LLC	HERTFORD CO., NC	1/9/2002	?	AUXILIARY BOILER	83	GCP AND DESIGN (< 1,000 HR/YR)	0.005	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	PICKLE LINE BOILER	22	NATURAL GAS COMBUSTION ONLY	0.006	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	VACUUM DEGASSER BOILER	51	NATURAL GAS COMBUSTION ONLY	0.006	BACT-PSD
MUSTANG ENERGY PROJECT	CANADIAN CO., OK	2/12/2002	?	AUXILIARY BOILER	31	GCP AND DESIGN	0.006	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	AUXILIARY BOILERS	31	GCP AND DESIGN	0.006	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CO., OK	8/16/2001	?	(2) AUXILIARY BOILERS	48	COMBUSTION CONTROL	0.006	BACT-PSD
FREMONT ENERGY CENTER, LLC	SANDUSKY CO., OH	8/9/2001	YES	AUXILIARY BOILER	80	NONE INDICATED	0.006	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	AUXILIARY BOILER	28	GCP AND DESIGN	0.006	BACT-PSD
LAWRENCE ENERGY	LAWRENCE CO., OH	9/24/2002	YES	BOILER	99	NONE INDICATED	0.006	BACT-PSD
ATOFINA CHEMICALS INCORPORATED	JEFFERSON CO., TX	12/19/2002	NO	(2) STEAM BOILERS	16	NONE INDICATED	0.006	OTHER
LA PORTE POLYPROPYLENE PLANT	HARRIS CO., TX	11/5/2001	NO	PACKAGE BOILER BO-4	60	NONE INDICATED	0.006	OTHER
WAUPACA FOUNDRY - PLANT 5	PERRY CO., IN	1/19/1996	?	BOILERS	94	NONE INDICATED	0.006	BACT-PSD
DRESDEN ENERGY LLC	MUSKINGUM CO., OH	10/16/2001	YES	BOILER	49	OPERATION LIMITED TO < 800 HR/YR	0.006	BACT-PSD
BAYTOWN CARBON BLACK PLANT	HARRIS CO., TX	12/31/2002	?	BACK-UP BOILER	13	NONE INDICATED	0.006	BACT-OTHER
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	BOILER	40	GOOD COMBUSTION	0.006	BACT-PSD
GENPOWER KELLEY LLC	WALKER CO., AL	1/12/2001	?	BOILER	83	EFFICIENT COMBUSTION (< 1,000 HR/YR)	0.006	BACT-PSD
R. R. DONNELLEY PRINTING COMPANY	CAMPBELL CO., VA	5/2/1994	YES	BOILER	47	NONE INDICATED	0.006	BACT-PSD
COCA COLA	LOS ANGELES CO., CA	11/23/1999	YES	SCOTCH MARINE CUSTOM FIRE-TUBE BOILER	32	NONE INDICATED	0.007	BACT-OTHER
CENTRAL SOYA COMPANY INC.	HURON CO., OH	11/29/2001	YES	BOILER	91	NONE INDICATED	0.007	BACT-PSD
REDBUD POWER PLT	OKLAHOMA CO., OK	5/6/2002	?	AUXILIARY BOILER	93	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.008	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	SUFFOLK CO., MA	9/29/1999	?	AUXILIARY BOILER	96	OPERATION LIMITED TO < 250 HR/YR	0.008	LAER
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	AUXILIARY BOILER	96	OPERATION LIMITED TO < 500 HR/YR	0.008	BACT-PSD
SCHERING CORPORATION	UNION CO., NJ	3/7/1996	?	BOILERS 4&5	94	NONE INDICATED	0.008	BACT-PSD
INDELK ENERGY SERVICES OF OTSEGO	ALLEGAN CO., MI	3/16/1993	?	BOILER	99	STATE-OF-THE-ART COMBUSTION CONTROLS	0.010	BACT-OTHER
DUKE ENERGY AUTAUGA, LLC	AUTAUGA CO., AL	10/23/2001	?	BOILER	31	EFFICIENT COMBUSTION (< 2,500 HR/YR)	0.010	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	LAWRENCE CO., IN	10/5/2001	?	AUXILIARY BOILER	35	CLEAN FUEL, GCP	0.011	BACT-PSD
JACKSON COUNTY POWER, LLC	JACKSON CO., OH	12/27/2001	YES	AUXILIARY BOILER	76	OPERATION LIMITED TO < 3,000 HR/YR	0.012	BACT-PSD
DUKE ENERGY WYTHE, LLC	RALEIGH, NC	2/5/2004	NO	AUXILIARY BOILER	37	NONE INDICATED	0.014	BACT-PSD
DUKE ENERGY DALE, LLC	DALE CO., AL	12/11/2001	?	AUXILIARY BOILER	35	GOOD COMBUSTION	0.014	BACT-PSD
PSEG WATERFORD ENERGY LLC	WASHINGTON CO., OH	3/29/2001	YES	AUXILIARY BOILER	93	OPERATION LIMITED TO < 1,000 HR/YR	0.014	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	AUXILIARY BOILER	33	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.015	BACT-PSD
CLOVIS ENERGY FACILITY	CURRY CO., NM	6/27/2002	?	(2) AUXILIARY BOILERS	33	CLEAN FUELS, GCP	0.015	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON CO., OH	1/18/2001	YES	BOILER	47	NONE INDICATED	0.015	BACT-PSD
DEMING ENERGY FACILITY	LUNA CO., NM	12/29/2000	?	AUXILIARY BOILER	44	GOOD COMBUSTION DESIGN	0.016	BACT-PSD
MURRAY ENERGY FACILITY	MURRAY CO., GA	10/23/2002	NO	AUXILIARY BOILER	36	GCP (< 6,000 HR/YR)	0.016	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON CO., AR	4/1/2002	?	AUXILIARY BOILER	33	GOOD OPERATING PRACTICE	0.016	BACT-PSD
WEBERS FALLS ENERGY FACILITY	MUSKOGEE CO., OK	10/22/2001	?	AUXILIARY BOILER	30	NONE INDICATED (< 3,000 HR/YR)	0.016	BACT-PSD
DUKE ENERGY HOT SPRINGS	HOT SPRINGS CO., AR	12/29/2000	?	(2) AUXILIARY BOILERS	44	CLEAN FUELS, PROPER COMBUSTION	0.016	BACT-PSD
CABOT POWER CORPORATION	SUFFOLK CO., MA	5/7/2000	?	AUXILIARY BOILER	27	COMB CONTROLS, OXIDATION CATALYST (< 500 HR/YR)	0.016	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	AUXILIARY BOILER	27	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.016	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	GRAYS HARBOR CO., WA	10/23/2001	?	AUXILIARY BOILER	29	NONE INDICATED	0.016	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEF I AND II)	ARLINGTON, AZ	11/6/2003	?	(2) AUXILIARY BOILERS	33	OPERATION LIMITED TO < 6,000 HR/YR	0.016	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE CO., OH	12/13/2001	YES	(2) BOILER	37	NONE INDICATED	0.016	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	AUXILIARY BOILER	21	ADEQUATE FUEL RESIDENCE TIME / PROPER COMB TEMP	0.016	BACT-PSD
GENOVA ARKANSAS I, LLC	WASHINGTON CO., AR	8/23/2002	YES	AUXILIARY BOILER	33	GCP	0.018	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	AUXILIARY BOILER	33	BOILER DESIGN AND GCP	0.018	BACT-PSD

Appendix E: Table E-15
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 MMBtu/hr)
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
GORDONSVILLE ENERGY L. P.	VIRGINIA	7/30/1993	?	AUXILIARY BOILER	22	GCP	0.018	NSPS
QUAD GRAPHICS OKC FAC	OKLAHOMA CO., OK	2/3/2004	?	BOILERS	27	MAINT/OPERATION PER MFGR'S SPECS (< 336 H/YR)	0.019	BACT-PSD
INDECK-ELWOOD, LLC	BUFFALO GROVE, IL	10/10/2003	NO	BOILER	99	OPERATION LIMITED TO < 2,500 HR/YR	0.020	BACT-PSD
BLOUNT MEGAWATT FACILITY	BLOUNT CO., AL	2/5/2001	?	AUXILIARY BOILER	40	GCP	0.020	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	AUXILIARY BOILER	25	OPERATION LIMITED TO < 1,000 HR/YR	0.020	LAER
GORDONSVILLE ENERGY L.P.	FAIRFAX CO., VA	9/25/1992	?	AUXILIARY BOILER	60	GCP	0.023	BACT-PSD
QUAD GRAPHICS OKC FACILITY	OKLAHOMA CO., OK	8/21/2001	?	BOILERS	63	GOOD COMBUSTION/MAINTENANCE	0.028	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	WYOMING CO., WY	5/31/1995	?	BOILERS #2 AND #4	70	REROUTING OF PULP PLANT EMISSIONS TO BOILERS 2 AND 4	0.028	RACT
VENTURA COASTAL CORP.	CALIFORNIA	11/17/1988	?	CLEAVER-BROOKS MODEL CB-400 BOILER	27	NONE INDICATED	0.076	OTHER
BOISE CASCADE CORPORATION - YAKIMA COMPLEX	YAKIMA CO., WA	11/16/1996	?	BOILERS	27	FUEL SPEC: NATURAL GAS	0.079	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-16
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	PM/PM-10 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SUN REFINING & MARKETING CO.	OHIO	11/2/1987	?	BOILER	68	NONE INDICATED	0.0005	OTHER
STAFFORD RAILSTEEL CORPORATION	CRITTENDEN CO., AR	8/17/1993	?	VTD BOILER	47	FUEL SPEC: NATURAL GAS USAGE	0.0011	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/21/2003	?	(2) BOILER	34	COMPLIANCE BY USING NATURAL GAS	0.0019	BACT-PSD
PRO TEC COATING COMPANY	PUTNAM CO., OH	2/15/2001	?	(4) BOILERS	21	NONE INDICATED	0.0019	SIP
TOLEDO SUPPLIER PARK- PAINT SHOP	LUCAS,OH	5/3/2007	NO	BOILER -2	20		0.0020	BACT-PSD
INDECK-ELWOOD, LLC	BUFFALO GROVE, IL	10/10/2003		BOILER	99	OPERATION LIMITED TO < 2,500 HR/YR	0.0029	BACT-PSD
I/N TEK	INDIANA	10/15/1987	?	(2) BOILER	73	NONE INDICATED	0.0030	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/30/1993	?	VACUUM DEGASSER BOILER	34	FUEL SPEC: NAT GAS FIRING	0.0030	BACT-PSD
CAITHNES BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	?	AUXILIARY BOILER	29	LOW SULFUR FUEL	0.0033	BACT-PSD
WELLTON MOHAWK GENERATINGSTATION	YUMA,AZ	12/1/2004	?	AUXILIARY BOILER	38		0.0033	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	NO	AUXILIARY BOILER	38	NG (S < 0.75 GR/100 SCF) OPERATION < 480 HR/YR	0.0033	BACT-OTHER
MERCK - RAHWAY PLANT	UNION CO., NJ	1/14/1997	?	(3) BOILERS	100	NONE INDICATED	0.0033	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX CO., VA	9/25/1992	?	AUXILIARY BOILER	60	FUEL SPEC: CLEAN BURNING FUEL	0.0033	BACT-PSD
KLAMATH GENERATION, LLC	KLAMATH CO., OR	3/12/2003	?	AUXILIARY BOILER	59	NONE INDICATED	0.0042	BACT-PSD
PANDA-ROSEMARY CORP.	NORTH CAROLINA	9/6/1989	?	(2) BOILER	81	COMBUSTION CONTROL	0.0048	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN,IA	6/29/2007	NO	NATURAL GAS BOILER (292.5 MMBTU/H)	293	NATURAL GAS FUEL ONLY	0.0050	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	AUXILIARY BOILER	99	NATURAL GAS ONLY	0.0050	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	TALLADEGA CO., AL	10/3/2001	?	AUXILIARY BOILER	30	NATURAL GAS AS EXCLUSIVE FUEL	0.0050	BACT-PSD
MID-GEORGIA COGEN.	HOUSTON CO., GA	4/3/1996	?	BOILER	60	COMPLETE COMBUSTION	0.0050	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	CCR STABILIZATION REBOILER	54	NONE INDICATED	0.0050	BACT-PSD
GORDONSVILLE ENERGY L. P.	VIRGINIA	7/30/1993	?	AUXILIARY BOILER	22	FUEL SPEC: CLEAN BURNING FUEL	0.0050	NSPS
CENTRAL SOYA COMPANY INC.	HURON CO., OH	11/29/2001	?	BOILER	91	NONE INDICATED	0.0050	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	AUXILIARY STEAM BOILER	80	CLEAN FUEL AND EFFICIENT COMBUSTION TECHNIQUES	0.0051	BACT-PSD
KAMINE/BESICORP CORNING L.P.	NEW YORK	11/5/1992	?	(3) AUXILIARY BOILERS	34	COMBUSTION CONTROL	0.0051	BACT-OTHER
FREMONT ENERGY CENTER, LLC	SANDUSKY CO., OH	8/9/2001	?	AUXILIARY BOILER	80	NONE INDICATED	0.0051	BACT-PSD
ARKANSAS EASTMAN CO.	ARKANSAS	7/14/1987	?	BOILER #4	78	NONE INDICATED	0.0051	OTHER
SCHERING CORPORATION	UNION CO., NJ	3/7/1996	?	BOILERS 4&5	94	NONE INDICATED	0.0052	BACT-PSD
REDBUD POWER PLT	OKLAHOMA CO., OK	5/6/2002	?	AUXILIARY BOILER	93	NATURAL GAS/LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0053	BACT-PSD
SHINTECH, INC.	BRAZORIA CO., TX	3/17/1980	?	(2) BOILER	55	NONE INDICATED	0.0055	BACT-PSD
R. R. DONNELLEY PRINTING COMPANY	CAMPBELL CO., VA	5/2/1994	?	BOILER	47	NONE INDICATED	0.0064	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	AUXILIARY BOILER	96	OPERATION < 500 HR/YR, SULFUR CONTENT < 0.8 GR/100 CF	0.0070	BACT-PSD
HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	AUXILIARY BOILER	49	GCP	0.0070	BACT-OTHER
CARGILL, INC	TIPPECANOE CO., IN	12/3/2001	?	(2) BOILERS 1 & 2	75	NONE INDICATED	0.0070	OTHER
VA POWER - POSSUM POINT	PRINCE WILLIAM CO., VA	11/18/2002	?	AUXILIARY BOILER	99	CLEAN FUEL AND GCP	0.0071	BACT-OTHER
COCA COLA	LOS ANGELES CO., CA	11/23/1999	?	FIRE TUBE BOILER	32	NONE INDICATED	0.0071	BACT-OTHER
NORTHSTAR DEVELOPMENT PROJECT	ALASKA	2/5/1999	NO	WASTE HEAT RECOVERY UNIT 10	53	GOOD OPERATION PRACTICES (< 1,000 HR/YR)	0.0072	BACT-OTHER
SHELL CHEMICAL COMPANY - GEISMAR PLANT	ASCENSION PARISH, LA	5/10/2000	?	C15/C16 COLUMN REBOILER FURNACE	21	GCP AND ENGINEERING DESIGN CLEAN BURNING FUEL	0.0072	BACT-PSD
CPV CUNNINGHAM CREEK	FLUVANNA CO., VA	9/6/2002	?	AUXILIARY BOILER	80	GCP	0.0073	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	SUFFOLK CO., MA	9/29/1999	?	AUXILIARY BOILER	96	NATURAL GAS FUEL	0.0073	BACT-PSD
OHIO RIVER PLANT	PLEASANTS,WV	6/9/2004	?	BOILER, NATURAL GAS 39.00 MMBTU	44		0.0073	BACT-PSD
CHARTER STEEL	CUYAHOGA,OH	6/10/2004	?	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	29		0.0073	BACT-PSD
TOLEDO SUPPLIER PARK- PAINT SHOP	LUCAS,OH	5/3/2007	NO	BOILER -2	20		0.0074	BACT-PSD
CRESCENT CITY POWER	ORLEANS,LA	6/6/2005	?	FUEL GAS HEATERS (3)	19	LOW SULFUR PIPELINE NATURAL GAS AND GCP	0.0074	BACT-PSD
THUNDERBIRD POWER PLT	CLEVELAND CO., OK	5/17/2001	?	AUXILIARY BOILER	20	USE OF LOW ASH FUEL	0.0074	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	TULSA CO., OK	10/1/1999	?	AUXILIARY BOILER	24	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0074	BACT-PSD
SOLAR GAS TURBINE COGEN.	ECTOR CO., TX	4/3/2000	?	AUXILIARY BOILER	54	S < 2.5 GRAINS TOTAL SULFUR PER 100 DSCF (SHORT-TERM) AND 0.5 GRAIN TOTAL SULFUR PER 100 DSCF (12-MONTH)	0.0074	NSPS
HARRISONBURG RESOURCE RECOVER FACILITY	HARRISONBURG, VA	3/24/2003	?	BOILER NO. 1	43	GCP	0.0074	NSPS
BAYTOWN CARBON BLACK PLANT	HARRIS CO., TX	12/31/2002	?	BACK-UP BOILER	13	NONE INDICATED	0.0075	BACT-OTHER
GENPOWER EARLEYS, LLC	HERTFORD CO., NC	1/9/2002	?	AUXILIARY BOILER	83	GOOD COMBUSTION AND DESIGN	0.0075	BACT-PSD
HARRAH'S OPERATING COMPANY, INC.	CLARK,NV	1/4/2007	NO	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35	USE OF NATURAL GAS AS THE ONLY FUEL	0.0075	BACT-PSD
BARTON SHOALS ENERGY	COLBERT CO., AL	7/12/2002	?	(2) AUXILIARY BOILERS	40	NATURAL GAS ONLY	0.0075	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	12/20/2002	?	AUXILIARY BOILER	68	LOW ASH FUEL, NG	0.0075	BACT-OTHER
DUKE ENERGY, VIGO LLC	VIGO CO., IN	6/6/2001	?	(2) AUXILIARY BOILERS	46	GOOD COMBUSTION	0.0075	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	ST. JOSEPH CO., IN	12/7/2001	?	AUXILIARY BOILER	21	NATURAL GAS AS SOLE FUEL	0.0075	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY CO., TN	4/3/2002	?	BOILER, NO. 9	95	NONE INDICATED	0.0075	BACT-PSD
STANLEY FURNITURE	HENRY CO., VA	12/1/2002	?	KEWANEE BOILER	27	NONE INDICATED	0.0075	BACT-OTHER
ATOFINA CHEMICALS INCORPORATED	JEFFERSON CO., TX	12/19/2002	NO	(2) STEAM BOILERS	16	NONE INDICATED	0.0076	OTHER
THYSSENKRUPP STEEL AND STAINLESS USA, LLC	MOBILE,AL	8/17/2007	NO	3 NAT GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	65		0.0076	BACT-PSD
NUCOR DECATUR LLC	MORGAN,AL	6/12/2007	NO	VACUUM DEGASSER BOILER	95		0.0076	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI,AR	7/22/2004	?	BOILERS	22	NATURAL GAS COMBUSTION ONLY	0.0076	BACT-PSD
HYUNDAI MOTOR MANUFACTURING OF ALABAMA,LLC	MONTGOMERY,AL	3/23/2004	?	BOILERS, NATURAL GAS (3)	50	CLEAN FUEL	0.0076	BACT-PSD
MUSTANG ENERGY PROJECT	CANADIAN CO., OK	2/12/2002	?	AUXILIARY BOILER	31	LOW ASH FUEL (NATURAL GAS)	0.0076	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	AUXILIARY BOILERS	31	LOW ASH FUEL (NATURAL GAS)	0.0076	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	6/19/1997	?	(2) BOILER	13	CLEAN FUEL	0.0076	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	6/19/1997	?	(2) BOILER	12	CLEAN FUEL	0.0076	BACT-PSD
HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	MONTGOMERY CO., AL	3/23/2004	?	(3) BOILERS	50	CLEAN FUEL	0.0076	BACT-PSD
HONDA MANUFACTURING OF ALABAMA, LLC	TALLADEGA CO., AL	10/18/2002	?	(3) BOILERS	30	CLEAN FUEL, GOOD COMBUSTION	0.0076	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	BOILERS	22	NATURAL GAS COMBUSTION ONLY	0.0076	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK CO., IA	4/10/2002	?	AUXILIARY BOILER	68	NONE INDICATED	0.0076	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CO., OK	8/16/2001	?	(2) AUXILIARY BOILERS	48	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0076	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	AUXILIARY BOILER	28	GCP AND DESIGN	0.0076	BACT-PSD
PORT WASHINGTON GENERATING STATION	WASHINGTON,WI	10/13/2004	?	NATURAL GAS FIRED AUXILLIARY BOILER	97	NATURAL GAS FUEL, GOOD COMBUSTION PRACTICES	0.0076	BACT-PSD
LAWRENCE ENERGY	LAWRENCE CO., OH	9/24/2002	?	BOILER	99	NONE INDICATED	0.0077	BACT-PSD
DRESDEN ENERGY LLC	MUSKINGUM CO., OH	10/16/2001	?	BOILER	49	NONE INDICATED	0.0078	BACT-PSD
GOODSPRINGS COMPRESSOR STATION	CLARK,NV	5/16/2006	?	COMMERCIAL/INSTITUTIONAL BOILER	4	GOOD COMBUSTION PRACTICE	0.0078	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	7/15/2004	?	BOILER, NATURAL GAS (1)	40	CLEAN FUEL AND GOOD COMBUSTION.	0.0080	BACT-PSD
MIRANT SUGAR CREEK, LLC	VIGO CO., IN	5/9/2001	?	(2) AUXILIARY BOILERS	35	GOOD COMBUSTION	0.0080	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	BOILER	40	CLEAN FUEL AND GOOD COMBUSTION	0.0080	BACT-PSD

Appendix E: Table E-16
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	PM/PM-10 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
LA PORTE POLYPROPYLENE PLANT	HARRIS CO., TX	11/5/2001	NO	PACKAGE BOILER BO-4	60	NONE INDICATED	0.0080	NSPS
OHIO RIVER PLANT	PLEASANTS CO., WV	6/9/2004	NO	BOILER	39	NONE INDICATED	0.0080	BACT-PSD
DUKE ENERGY WYTHE, LLC	RALEIGH, NC	2/5/2004	NO	AUXILIARY BOILER	37	PIPELINE NATURAL GAS	0.0082	BACT-PSD
RINCON POWER PLANT	EFFINGHAM CO., GA	3/24/2003	?	AUXILIARY BOILER	83	NONE INDICATED	0.0084	BACT-OTHER
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	NO	(2) HOT WATER BOILER	12	NATURAL GAS ONLY	0.0085	BACT-PSD
DUKE ENERGY DALE, LLC	DALE CO., AL	12/11/2001	?	AUXILIARY BOILER	35	NATURAL GAS AS EXCLUSIVE FUEL	0.0090	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	AUTAUGA CO., AL	10/23/2001	?	BOILER	31	NATURAL GAS IS EXCLUSIVE FUEL	0.0090	BACT-PSD
PSEG WATERFORD ENERGY LLC	WASHINGTON CO., OH	3/29/2001	?	AUXILIARY BOILER	93	NONE INDICATED	0.0090	BACT-PSD
MCCLAIN ENERGY FACILITY	MCCLAIN CO., OK	10/25/2001	?	AUXILIARY BOILER	22	USE OF LOW ASH FUELS	0.0090	BACT-PSD
DEMING ENERGY FACILITY	LUNA CO., NM	12/29/2000	?	AUXILIARY BOILER	44	NATURAL GAS ONLY, PRE-FILTERING	0.0091	BACT-PSD
CARGILL INC - SIOUX CITY	WOODBURY CO., IA	6/1/1998	?	BACKUP BOILER	77	NONE INDICATED	0.0091	BACT-PSD
CLOVIS ENERGY FACILITY	CURRY CO., NM	6/27/2002	?	(2) AUXILIARY BOILERS	33	NATURAL GAS ONLY, GCP	0.0091	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON CO., OH	1/18/2001	?	BOILER	47	NONE INDICATED	0.0094	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON,AR	2/17/2004	?	BOILER,PROCESS STEAM (2) SN-PBCDF-03 -04	32	NATURAL GAS ONLY.	0.0095	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	GRAYS HARBOR CO., WA	10/23/2001	?	AUXILIARY BOILER	29	NONE INDICATED	0.0100	BACT-OTHER
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	AUXILIARY BOILER	27	BOILER DESIGN AND GOOD OPERATING PRACTICES	0.0100	BACT-PSD
GENPOWER KELLEY LLC	WALKER CO., AL	1/12/2001	?	BOILER	83	EFFICIENT COMBUSTION	0.0100	BACT-PSD
DUKE ENERGY HOT SPRINGS	HOT SPRINGS CO., AR	12/29/2000	?	(2) AUXILIARY BOILERS	44	CLEAN FUELS, PROPER COMBUSTION	0.0100	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON CO., AR	4/1/2002	?	AUXILIARY BOILER	33	GOOD OPERATING PRACTICE	0.0100	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEF I AND II)	ARLINGTON, AZ	11/6/2003	?	(2) AUXILIARY BOILERS	33	OPERATION LIMITED TO < 6,000 HR/YR	0.0100	BACT-PSD
MURRAY ENERGY FACILITY	MURRAY CO., GA	10/23/2002	NO	AUXILIARY BOILER	36	GCP, CLEAN FUEL (< 6,000 HR/YR)	0.0100	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	ASCENSION PARISH, LA	2/13/1998	?	BOILER NO. 1	95	GOOD DESIGN, PROPER OPER PRACTICES &NAT GAS AS FUEL	0.0100	BACT-PSD
CABOT POWER CORPORATION	SUFFOLK CO., MA	5/7/2000	?	AUXILIARY BOILER	27	NATURAL GAS FUEL	0.0100	BACT-PSD
WEBERS FALLS ENERGY FACILITY	MUSKOGEE CO., OK	10/22/2001	?	AUXILIARY BOILER	30	LOW ASH FUEL & EFFICIENT COMBUSTION (< 3,000 HR/YR)	0.0100	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	AUXILIARY BOILER	33	GCP	0.0100	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	AUXILIARY BOILER	33	GCP	0.0100	BACT-PSD
SWEC-FALLS TOWNSHIP	GLEN ALLEN, PA	8/7/2001	?	AUXILIARY BOILER	41	NATURAL GAS ONLY	0.0100	BACT-PSD
MAPEE ALCOHOL FUEL, INC.	MOORE CO., TX	3/27/1981	?	AUXILIARY BOILER	35	FUEL SPEC: USE OF NAT. GAS FUEL	0.0100	BACT-PSD
INTERNATIONAL PAPER CO.	DALLAS CO., TX	2/4/1984	?	PACKAGE BOILER	15	NONE INDICATED	0.0100	BACT-PSD
QUAD GRAPHICS OKC FACILITY	OKLAHOMA CO., OK	8/21/2001	?	BOILERS	63	NATURAL GAS FUEL, GCP	0.0100	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE CO., OH	12/13/2001	?	(2) BOILER	37	NONE INDICATED	0.0101	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE,OH	12/28/2004	?	BOILERS (2)	31		0.0101	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	ONONDAGA CO., NY	12/10/1994	?	(3) UTILITY BOILERS	33	FUEL SPECIFICATION: SULFUR CONTENT < 0.15% BY WEIGHT	0.0103	BACT-OTHER
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	NO	(2) PROCESS STEAM BOILER	28	NATURAL GAS ONLY	0.0106	BACT-PSD
GENOVA ARKANSAS I, LLC	WASHINGTON CO., AR	8/23/2002	?	AUXILIARY BOILER	33	GCP	0.0120	BACT-PSD
O.H. KRUSE GRAIN AND MILLING	CALIFORNIA	9/19/1996	?	BOILER USED AS A BACKUP	10	NONE INDICATED	0.0120	LAER
ARCHER DANIELS MIDLAND - VALDESTA, GA	LOWNDES CO., GA	10/12/1995	NO	CLEAVER-BROOKS BOILER	75	NONE INDICATED	0.0133	BACT-OTHER
BMW MANUFACTURING CORP.	SPARTANBURG CO., SC	1/7/1994	?	(3) AUXILIARY BOILERS	60	NONE INDICATED	0.0137	BACT-PSD
DARLING INTERNATIONAL	FRESNO CO., CA	12/30/1996	?	NEBRASKA BOILER MODEL NS-B-40	31	NONE INDICATED	0.0137	LAER
WAUPACA FOUNDRY - PLANT 5	PERRY CO., IN	1/19/1996	?	BOILERS	94	NONE INDICATED	0.0137	BACT-PSD
ROCHE VITAMINS	WARREN CO., NJ	2/5/1999	?	BOILER 1	84	NONE INDICATED	0.0142	BACT-PSD
PPG INDUSTRIES, INC.	TEXAS	5/27/1981	?	(2) BOILER	21	NONE INDICATED	0.0143	BACT-PSD
DOW CORNING CORP.	CARROLL CO., KY	1/7/1991	?	POWER BOILERS	97	NONE INDICATED	0.0150	OTHER
WPS - WESTON PLANT	MARATHON,WI	8/27/2004	?	NATURAL GAS FIRED BOILER	46	NATURAL GAS	0.0173	N/A
ARCHER DANIELS MIDLAND - VALDESTA, GA	LOWNDES CO., GA	10/12/1995	NO	NEBRASKA BOILER	28	NONE INDICATED	0.0179	NSPS
ARCHER DANIELS MIDLAND - VALDESTA, GA	LOWNDES CO., GA	10/12/1995	NO	CLEAVER-BROOKS BOILER	75	NONE INDICATED	0.0179	BACT-OTHER
BLOUNT MEGAWATT FACILITY	BLOUNT CO., AL	2/5/2001	?	AUXILIARY BOILER	40	GCP	0.0200	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	LAWRENCE CO., IN	10/5/2001	?	AUXILIARY BOILER	35	CLEAN FUEL, GCP	0.0200	BACT-OTHER
KAISER ALUMINUM & CHEMICAL CORP.	OHIO	9/24/1986	?	BOILER	17	NONE INDICATED	0.0200	OTHER
JACKSON COUNTY POWER, LLC	JACKSON CO., OH	12/27/2001	?	AUXILIARY BOILER	76	NONE INDICATED	0.0200	BACT-PSD
QUAD GRAPHICS OKC FAC	OKLAHOMA CO., OK	2/3/2004	?	BOILERS	27	CLEAN FUELS	0.0230	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	AUXILIARY BOILER	21	PROPER COMBUSTION CONTROL,NATURAL GAS ONLY	0.0500	BACT-PSD
PORT HUDSON OPERATIONS	E. BATON ROUGE PARISH, LA	1/25/2002	?	POWER BOILER NO. 2	66	FIRED BY NATURAL GAS	0.0508	BACT-PSD
MINNESOTA MINING AND MANUFACTURING (3M)	KENTUCKY	7/10/1991	?	BOILER	40	LOW SULFUR FUEL	0.0850	OTHER
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	RANSOM CO., ND	7/9/1998	?	NEBRASKA BOILER	28	NONE INDICATED	0.0857	BACT-PSD
TOYOTA MOTOR MANUFACTURING, USA, INC	SCOTT CO., KY	5/29/1997	?	BOILER	96	FABRIC FILTER	0.1000	BACT-PSD
TOYOTA MOTOR MANUFACTURING	SCOTT CO., KY	6/21/1991	?	BOILER	96	LOW SULFUR FUEL	0.1000	BACT-PSD
INDECK-YERKES ENERGY SERVICES	ERIE CO., NY	6/24/1992	?	AUXILIARY BOILER	99	NONE INDICATED	0.1000	BACT-OTHER
AMTRAK	PENNSYLVANIA	10/12/1988	?	(2) BOILER	90	NONE INDICATED	0.1000	OTHER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	AUXILIARY BOILER	25	OPERATION LIMITED TO < 1,000 HR/YR	0.1200	BACT-PSD
GENERAL ELECTRIC CO.	INDIANA	9/17/1989	?	BOILER	93	LNB	0.1570	OTHER
TOYOTA MOTOR CORPORATION SVCS OF N.A.	GIBSON CO., IN	8/9/1996	?	(6) BOILERS	58	LNB & FUEL SPEC: USE OF NATURAL GAS AS FUEL	0.2000	BACT-PSD
QUEBECOR WORLD FRANKLIN	SIMPSON CO., KY	7/12/2002	NO	BOILER #4	34	NONE INDICATED	0.3080	BACT-PSD
DART CONTAINER CORP OF PA	LANCASTER CO., PA	12/14/2001	YES	(2) CLEAVER BROOKS BOILERS	34	NONE INDICATED	0.4000	NSPS
SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH	SWEETWATER CO., WY	2/6/1998	?	BOILER	100	MINIMAL PARTICULATE EMISSIONS AND LOW EMITTING FUEL	5.0000	BACT-PSD

Appendix E: Table E-17
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	SO_2 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	?	FUEL GAS HEATERS (3)	19	NONE INDICATED	0.0004	BACT-PSD
PPG INDUSTRIES, INC.	TEXAS	5/27/1981	YES	(2) BOILER	21	FUEL SPEC: NATURAL GAS FIRING	0.0005	BACT-PSD
TOLEDO SUPPLIER PARK- PAINT SHOP	LUCAS, OH	5/3/2007	?	BOILER -2	20	NONE INDICATED	0.0005	UNKNOWN
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK, NY	5/10/2006	NO	AUXILIARY BOILER	29	NONE INDICATED	0.0005	BACT-PSD
PSEG WATERFORD ENERGY LLC	WASHINGTON CO., OH	3/29/2001	YES	AUXILIARY BOILER	93	LOW S NATURAL GAS 2 GR/100 SCF	0.0005	BACT-PSD
INDECK-ELWOOD, LLC	BUFFALO GROVE, IL	10/10/2003		BOILER	99	OPERATION LIMITED TO < 2,500 HR/YR	0.0006	BACT-PSD
PANDA-ROSEMARY CORP.	NORTH CAROLINA	9/6/1989	YES	(2) BOILER	81	FUEL SPEC: LOW S FUEL	0.0006	BACT-PSD
WAUPACA FOUNDRY - PLANT 5	PERRY CO., IN	1/19/1996	YES	BOILERS	94	NONE INDICATED	0.0006	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI CO., AR	7/22/2004	NO	BOILERS	22	NATURAL GAS COMBUSTION ONLY	0.0006	BACT-PSD
NUCOR STEEL	MONTGOMERY CO., IN	11/21/2003	YES	(2) BOILER	34	COMPLIANCE BY USING NATURAL GAS	0.0006	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	12/20/2002	YES	AUXILIARY BOILER	68	LOW SULFUR FUEL, NG	0.0006	BACT-OTHER
ALLEGHENY ENERGY SUPPLY CO. LLC	ST. JOSEPH CO., IN	12/7/2001	YES	AUXILIARY BOILER	21	LOW SULFUR CONTENT NATURAL GAS	0.0006	BACT-PSD
DUKE ENERGY, VIGO LLC	VIGO CO., IN	6/6/2001	YES	(2) AUXILIARY BOILERS	46	NATURAL GAS AS FUEL	0.0006	BACT-PSD
MIRANT SUGAR CREEK, LLC	VIGO CO., IN	5/9/2001	YES	(2) AUXILIARY BOILERS	35	LOW SULFUR NATURAL GAS ONLY (LESS THAN 0.8% BY WEIGHT)	0.0006	BACT-PSD
MAPEE ALCOHOL FUEL, INC.	MOORE CO., TX	3/27/1981	YES	AUXILIARY BOILER	35	FUEL SPEC: USE OF NAT. GAS FUEL	0.0006	BACT-PSD
BLUEWATER PROJECT	MISSISSIPPI, AR	7/22/2004	?	BOILERS	22	NONE INDICATED	0.0006	BACT-PSD
NUCOR DECATUR LLC	MORGAN, AL	6/12/2007	?	VACUUM DEGASSER BOILER	95	NONE INDICATED	0.0006	BACT-PSD
CENTRAL SOYA COMPANY INC.	HURON CO., OH	11/29/2001	YES	BOILER	91	NONE INDICATED	0.0006	SIP
PORT WASHINGTON GENERATING STATION	WASHINGTON, WI	10/13/2004	?	NATURAL GAS FIRED AUXILLIARY BOILER	97	USE OF NAT GAS	0.0006	BACT-PSD
ATOFINA CHEMICALS INCORPORATED	JEFFERSON CO., TX	12/19/2002	NO	(2) STEAM BOILERS	16	SWEET NATURAL GAS CONTAINING < 5 GR S/100 DSCF	0.0006	OTHER
STAFFORD RAILSTEEL CORPORATION	CRITTENDEN CO., AR	8/17/1993	YES	VTD BOILER	47	FUEL SPEC: NATURAL GAS USAGE	0.0006	OTHER
COPPER MOUNTAIN POWER	CLARK, NV	5/14/2004	?	AUXILIARY BOILER	60	NONE INDICATED	0.0007	UNKNOWN
CHARTER STEEL	CUYAHOGA, OH	6/10/2004	?	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	29	NONE INDICATED	0.0007	BACT-PSD
BAYTOWN CARBON BLACK PLANT	HARRIS CO., TX	12/31/2002	YES	BACK-UP BOILER	13	NONE INDICATED	0.0007	BACT-OTHER
COCA COLA	LOS ANGELES CO., CA	11/23/1999	YES	FIRE TUBE BOILER	32	NONE INDICATED	0.0008	BACT-OTHER
KAISER ALUMINUM & CHEMICAL CORP.	OHIO	9/24/1986	YES	BOILER	17	NONE INDICATED	0.0008	OTHER
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	AUXILIARY BOILER	21	PIPELINE QUALITY NATURAL GAS	0.0010	BACT-PSD
MCCLAIN ENERGY FACILITY	MCCLAIN CO., OK	10/25/2001	YES	AUXILIARY BOILER	22	USE OF PIPELINE QUALITY NATURAL GAS	0.0010	BACT-PSD
MERCK - RAHWAY PLANT	UNION CO., NJ	1/14/1997	YES	(3) BOILERS	100	NONE INDICATED	0.0010	BACT-PSD
VA POWER - POSSUM POINT	PRINCE WILLIAM CO., VA	11/18/2002	YES	AUXILIARY BOILER	99	LOW SULFUR FUEL AND GCP	0.0010	BACT-OTHER
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE CO., OH	12/13/2001	YES	(2) BOILER	37	THE MAXIMUM S CONTENT < 2 GRAINS PER 100 CUBIC FEET	0.0010	BACT-PSD
DRESDEN ENERGY LLC	MUSKINGUM CO., OH	10/16/2001	YES	BOILER	49	THE MAXIMUM SULFUR CONTENT < 0.3 GRAINS PER 100 SCF	0.0010	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	GRAYS HARBOR CO., WA	10/23/2001	YES	AUXILIARY BOILER	29	NONE INDICATED	0.0010	BACT-PSD
WPS - WESTON PLANT	MARATHON, WI	8/27/2004	?	NATURAL GAS FIRED BOILER	46	USE OF NAT GAS	0.0011	UNKNOWN
ROCHE VITAMINS	WARREN CO., NJ	2/5/1999	YES	BOILER 1	84	NONE INDICATED	0.0012	BACT-PSD
ANNISTON ARMY DEPOT	CALHOUN CO., AL	6/19/1997	YES	(2) BOILER	13	CLEAN FUEL	0.0012	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	AUXILIARY BOILER	25	OPERATION LIMITED TO < 1,000 HR/YR	0.0012	BACT-PSD
SWEC-FALLS TOWNSHIP	GLEN ALLEN, PA	8/7/2001	?	AUXILIARY BOILER	41	NATURAL GAS ONLY	0.0020	BACT-PSD
CABOT POWER CORPORATION	SUFFOLK CO., MA	5/7/2000	YES	AUXILIARY BOILER	27	NATURAL GAS FUEL OF < .8 GRAINS PER 100 SCF	0.0022	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	NO	AUXILIARY BOILER	38	NG (S < 0.75 GR/100 SCF) OPERATION LIMITED TO < 480 HR/YR	0.0023	BACT-OTHER
WELLTON MOHAWK GENERATINGSTATION	YUMA, AZ	12/1/2004	?	AUXILIARY BOILER	38	NONE INDICATED	0.0023	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEF I AND II)	ARLINGTON, AZ	11/6/2003	?	(2) AUXILIARY BOILERS	33	OPERATION LIMITED TO < 6,000 HR/YR	0.0024	BACT-PSD
GOODSPRINGS COMPRESSOR STATION	CLARK, NV	5/16/2006	?	COMMERCIAL/INSTITUTIONAL BOILER	4	NONE INDICATED	0.0026	BACT-PSD
REDBUD POWER PLT	OKLAHOMA CO., OK	5/6/2002	YES	AUXILIARY BOILER	93	USE OF NATURAL GAS/LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0029	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	AUXILIARY BOILER	96	OPERATION < 500 HR/YR, SULFUR CONTENT < 0.8 GR/100 CF	0.0029	BACT-PSD
CLOVIS ENERGY FACILITY	CURRY CO., NM	6/27/2002	YES	(2) AUXILIARY BOILERS	33	NATURAL GAS ONLY, GCP	0.0030	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	SUFFOLK CO., MA	9/29/1999	YES	AUXILIARY BOILER	96	NATURAL GAS FUEL < .8 GRAINS OF SULFUR PER 100 CU FT	0.0031	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	NO	(2) PROCESS STEAM BOILER	28	LOW-SULFUR NATURAL GAS ONLY	0.0035	BACT-PSD
PORT HUDSON OPERATIONS	E. BATON ROUGE PARISH, LA	1/25/2002	YES	POWER BOILER NO. 2	66	FIRING NATURAL GAS	0.0040	BACT-PSD
MUSTANG ENERGY PROJECT	CANADIAN CO., OK	2/12/2002	YES	AUXILIARY BOILER	31	< 2 GR/100 SCF SULFUR	0.0056	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	YES	AUXILIARY BOILERS	31	< 2 GR/100 SCF SULFUR	0.0056	BACT-PSD
LAWRENCE ENERGY	LAWRENCE CO., OH	9/24/2002	YES	BOILER	99	NONE INDICATED	0.0057	BACT-PSD
DUKE ENERGY DALE, LLC	DALE CO., AL	12/11/2001	YES	AUXILIARY BOILER	35	NATURAL GAS	0.0057	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	AUTAUGA CO., AL	10/23/2001	YES	BOILER	31	NATURAL GAS IS EXCLUSIVE FUEL	0.0057	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	LAWRENCE CO., IN	10/5/2001	YES	AUXILIARY BOILER	35	GCP	0.0060	BACT-PSD
FREMONT ENERGY CENTER, LLC	SANDUSKY CO., OH	8/9/2001	YES	AUXILIARY BOILER	80	NONE INDICATED	0.0060	BACT-PSD
BLOUNT MEGAWATT FACILITY	BLOUNT CO., AL	2/5/2001	YES	AUXILIARY BOILER	40	GCP	0.0060	BACT-PSD
DUKE ENERGY HOT SPRINGS	HOT SPRINGS CO., AR	12/29/2000	YES	(2) AUXILIARY BOILERS	44	LOW SULFUR FUELS	0.0060	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	TULSA CO., OK	10/1/1999	YES	AUXILIARY BOILER	24	USE OF NATURAL GAS	0.0060	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	YES	AUXILIARY BOILER	28	USE OF NATURAL GAS WITH LOW SULFUR CONTENT	0.0060	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON CO., OH	1/18/2001	YES	BOILER	47	NONE INDICATED	0.0060	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	YES	AUXILIARY BOILER	33	LOW SULFUR FUEL	0.0061	BACT-PSD
JACKSON COUNTY POWER, LLC	JACKSON CO., OH	12/27/2001	YES	AUXILIARY BOILER	76	LOW SULFUR FUEL, NATURAL GAS SULFUR LIMIT - 2 GR/100 SCF	0.0066	BACT-PSD
U.S. ARMY, PINE BLUFF ARSENAL	JEFFERSON CO., AR	2/17/2004	YES	(2) HOT WATER BOILER	12	LOW-SULFUR NATURAL GAS ONLY	0.0085	BACT-PSD
SOLAR GAS TURBINE COGEN.	ECTOR CO., TX	4/3/2000	YES	AUXILIARY BOILER	54	< 2.5 GRAINS TOTAL SULFUR PER 100 DSCF (SHORT-TERM) AND 0.5 GRAIN TOTAL SULFUR PER 100 DSCF (12-MONTH)	0.0143	NSPS
ARKANSAS EASTMAN CO.	ARKANSAS	7/14/1987	YES	BOILER #4	78	FUEL SPEC: MAX SULFUR LIMIT	0.0154	OTHER
LA PORTE POLYPROPYLENE PLANT	HARRIS CO., TX	11/5/2001	YES	PACKAGE BOILER BO-4	60	NONE INDICATED	0.0158	NSPS
HULS AMERICA	MOBILE CO., AL	8/31/1990	YES	(2) BOILERS	39	LOW SULFUR NATURAL GAS	0.0411	BACT-PSD
HARRISONBURG RESOURCE RECOVER FACILITY	HARRISONBURG, VA	3/24/2003	YES	BOILER NO. 1	43	CEM SYSTEM AND GCP	0.0507	NSPS
SUNLAND REFINERY	CALIFORNIA	9/24/1992	YES	(2) BOILERS	13	FUEL SPEC: LOW SULFUR FUEL	0.1690	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CO., OK	8/16/2001	YES	(2) AUXILIARY BOILERS	48	NATURAL GAS W/SULFUR CONTENT 2 GRAINS SULFUR/100 SCF	0.2000	BACT-PSD
CPV WARREN	WARREN, VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 3	62	NONE INDICATED	0.2000	UNKNOWN
INTERNATIONAL PAPER CO.	DALLAS CO., TX	2/4/1984	YES	PACKAGE BOILER	15	FUEL SPEC:	0.2200	BACT-PSD
MINNESOTA MINING AND MANUFACTURING (3M)	KENTUCKY	7/10/1991	YES	BOILER	40	LOW SULFUR FUEL	0.2240	OTHER
CALIFORNIA DEPT. OF CORRECTIONS	CALIFORNIA	12/18/1987	YES	(2) BOILER	36	FUEL SPEC: LOW S FUEL, <0.12% S	0.2431	BACT-PSD
WEBERS FALLS ENERGY FACILITY	MUSKOGEE CO., OK	10/22/2001	YES	AUXILIARY BOILER	30	USE OF NATURAL GAS (< 3,000 HR/YR)	0.2533	BACT-PSD
TOYOTA MOTOR MANUFACTURING, USA, INC	SCOTT CO., KY	5/29/1997	YES	BOILER	96	THE SULFUR CONTENT OF NO.2 FUEL < 0.3%	0.3000	BACT-PSD
TOYOTA MOTOR MANUFACTURING	SCOTT CO., KY	6/21/1991	YES	BOILER	96	SULFUR CONTENT LIMITED	0.3000	OTHER
CPV WARREN	WARREN, VA	1/14/2008	NO	AUXILIARY BOILER - SCENARIO 2	97	NONE INDICATED	0.3200	UNKNOWN
R. R. DONNELLEY PRINTING COMPANY	CAMPBELL CO., VA	5/2/1994	YES	BOILER	47	NONE INDICATED	0.4170	BACT-PSD
MICHELIN NORTH AMERICA, INC.	LEXINGTON CO., SC	8/14/1996	YES	(2) BOILERS	95	USE OF NATURAL GAS AS PRIMARY FUEL	0.5000	BACT-PSD
DOW CORNING CORP.	CARROLL CO., KY	1/7/1991	YES	POWER BOILERS	97	CLEAN BURNING FUEL	0.5000	BACT-PSD
STANLEY FURNITURE	HENRY CO., VA	12/1/2002	YES	KEWANEE BOILER	27	NONE INDICATED	0.5132	BACT-OTHER

Appendix E: Table E-17
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas-Fired Auxiliary Boilers (10 - 100 mmBtu/hr)
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT MMBTU/HR	CONTROL DESCRIPTION	SO_2 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
QUEBECOR WORLD FRANKLIN	SIMPSON CO., KY	7/12/2002	YES	BOILER #4	34	CLEAN FUEL	1.0570	BACT-PSD
BADAMI DEVELOPMENT FACILITY	NORTH SLOPE ,AK	8/19/2005	?	NATCO TEG REBOILER	1	NONE INDICATED	1.2800	BACT-PSD
NORTHSTAR DEVELOPMENT PROJECT	ALASKA	2/5/1999	YES	WASTE HEAT RECOVERY UNIT 10	53	H2S CONTENT OF NATURAL GAS FUEL < 50 PPMV (< 1,000 HR/YR)	2.5500	BACT-OTHER
DART CONTAINER CORP OF PA	LANCASTER CO., PA	12/14/2001	YES	(2) CLEAVER BROOKS BOILERS	34	LOW SULFUR FUEL	4.0000	NSPS
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	YES	BOILER	40	LOW SULFUR FUEL 0.8 GR/SCF CALENDAR YEAR AVERAGE	--	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON CO., AR	4/1/2002	YES	AUXILIARY BOILER	33	FUELS LIMIT: < 2 GR/100 DSCF	--	BACT-PSD
SCHERING CORPORATION	UNION CO., NJ	3/7/1996	YES	BOILERS 4&5	94	NONE INDICATED	--	BACT-PSD

Appendix E: Table E-18
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas Fuel Heaters
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	3/1/2004	?	DEW POINT HEATER	8.4	NONE INDICATED	0.036	BACT-PSD
OCEAN PEAKING POWER	LAKEWOOD, NJ	2002	YES	(3) GAS HEATER	4.6	LOW NOX FORCED DRAFT BURNERS	0.036	LAER
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	?	NATURAL GAS BOILER	11.0	NONE INDICATED	0.040	BACT-PSD
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	4/10/2002	?	(2) EFFICIENCY HEATERS #1,#2	18.5	NONE INDICATED	0.041	BACT-PSD
POWER IOWA ENERGY CENTER	CEDAR RAPIDS, IA	12/20/2002	?	(2) GAS HEATERS (EU3&EU4)	20.0	DLN BURNER	0.049	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	DEW POINT HEATER	9.0	DLN	0.049	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) GAS PREHEATERS	3.08	NATURAL GAS ONLY	0.050	LAER
ENTERGY HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	(2) FUEL PREHEATER	6.5	NONE INDICATED	0.054	BACT-PSD
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK CO, NY	5/10/2006	NO	FUEL GAS PREHEATER	5.0	FORCED DRAFT LNB	0.058	LAER
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) FUEL SUPPLY HEATERS	11.5	NONE INDICATED	0.094	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) RECUPERATOR PRE-HEATERS	12.8	NONE INDICATED	0.094	BACT-PSD
CRESENT CITY POWER, LLC	ORLEANS CO, LA	6/6/2005	NO	(3) FUEL GAS HEATERS	19.0	NONE INDICATED	0.095	BACT-PSD
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	NATURAL GAS HEATER	5.0	NONE INDICATED	0.096	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	(2) NATURAL GAS HEATER STATIONS	0.8	FIRING NATURAL GAS	0.097	BACT
WEPCO PORT WASHINGTON GENERATING STA	WASHINGTON CO, WI	10/13/2004	?	GAS CONDITIONING HEATER	10.0	NONE INDICATED	0.100	N/A
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FUEL PREHEATER	7.0	NONE INDICATED	0.100	BACT
TALBOT ENERGY FACILITY	TALBOT CO, GA	6/9/2003	?	(3) FUEL GAS PREHEATERS	5.0	DLN BURNERS	0.110	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	FUEL DEW POINT HEATER	3.7	LNB	0.110	LAER
AES RED OAK LLC	MIDDLESEX CO., NJ	10/24/2001	?	FUEL GAS HEATER	16.2	NONE INDICATED	0.120	LAER
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG	12/23/2002	YES	HEATER, STARTUP GAS	2.4	NONE INDICATED	0.140	BACT-PSD
NUCOR STEEL CORP.	STANTON, NE	6/22/2004	?	BILET POST HEATER	6.8	NONE INDICATED	0.147	OTHER
ROQUETTE AMERICA	LEE CO., IA	1/31/2003	?	DEW POINT HEATER	1.6	GCP	0.150	BACT-PSD
QUAD GRAPHICS	OKLAHOMA	2/3/2004	?	HEATERS	16.0	NONE INDICATED	0.155	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	FUEL GAS WATER BATH HEATER	13.4	HEATER DESIGN & GOOD OPER PRACTICES	0.179	BACT-PSD
MCINTOSH COMBINED CYCLE FACILITY	EFFINGHAM CO, GA	4/17/2003	?	FUEL GAS HEATER	5.0	NONE INDICATED	0.370	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES, LNB = LOW NOX BURNERS

Appendix E: Table E-19
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas Fuel Heaters
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
TALBOT ENERGY FACILITY	TALBOT CO, GA	6/9/2003	?	(3) FUEL GAS PREHEATERS	5.0	GCP	0.022	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	FUEL GAS WATER BATH HEATER	13.4	HEATER DESIGN & GOOD OPER PRACTICES	0.025	BACT-PSD
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	4/10/2002	?	(2) EFFICIENCY HEATERS #1,#2	18.5	NONE INDICATED	0.032	BACT-PSD
ENTERGY HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	(2) FUEL PREHEATER	6.5	NONE INDICATED	0.033	BACT-PSD
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	3/1/2004	?	DEW POINT HEATER	8.4	NONE INDICATED	0.036	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) RECUPERATOR PRE-HEATERS	12.8	NONE INDICATED	0.040	BACT-PSD
WEPCO PORT WASHINGTON GENERATING STA	WASHINGTON CO, WI	10/13/2004	?	GAS CONDITIONING HEATER	10.0	NONE INDICATED	0.047	BACT-PSD
AES RED OAK LLC	MIDDLESEX CO., NJ	10/24/2001	?	FUEL GAS HEATER	16.2	GCP	0.054	BACT-PSD
CRESENT CITY POWER, LLC	ORLEANS CO, LA	6/6/2005	NO	(3)FUEL GAS HEATERS	19.0	NONE INDICATED	0.080	BACT-PSD
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004		NATURAL GAS BOILER	11.0	NONE INDICATED	0.080	BACT-PSD
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	(2) NATURAL GAS HEATER STATIONS	0.8	FIRING NATURAL GAS	0.080	BACT
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	NATURAL GAS HEATER	5.0	GCP	0.082	BACT
POWER IOWA ENERGY CENTER	CEDAR RAPIDS, IA	12/20/2002	?	(2) GAS HEATERS (EU3&EU4)	20.0	NONE INDICATED	0.082	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	DEW POINT HEATER	9.0	GCP	0.082	BACT-PSD
MCINTOSH COMBINED CYCLE FACILITY	EFFINGHAM CO, GA	4/17/2003	?	FUEL GAS HEATER	5.0	NONE INDICATED	0.083	BACT-PSD
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK CO, NY	5/10/2006	NO	FUEL GAS PREHEATER	5.0	GCP	0.084	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) GAS PREHEATERS	3.08	NATURAL GAS ONLY	0.084	BACT
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) FUEL SUPPLY HEATERS	11.5	NONE INDICATED	0.084	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FUEL PREHEATER	7.0	NONE INDICATED	0.084	BACT
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	FUEL DEW POINT HEATER	3.7	GCP	0.092	BACT
OCEAN PEAKING POWER	LAKEWOOD, NJ	2002	YES	(3) GAS HEATER	4.6	NONE INDICATED	0.150	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-20
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas Fuel Heaters
Volatile Organic Compounds Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	NATURAL GAS HEATER	5.0	GCP	0.005	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	(2) NATURAL GAS HEATER STATIONS	0.8	FIRING NATURAL GAS	0.005	BACT
POWER IOWA ENERGY CENTER	CEDAR RAPIDS, IA	12/20/2002	?	(2) GAS HEATERS (EU3&EU4)	20.0	NONE INDICATED	0.005	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	GAS HEATER	9.0	GCP	0.005	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	GAS HEATER	16.4	NONE INDICATED	0.005	Other Case-by-Case
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FUEL PREHEATER	7.0	NONE INDICATED	0.006	BACT
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	FUEL DEW POINT HEATER	3.7	GCP	0.006	LAER
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	3/1/2004	?	DEW POINT HEATER	8.4	NONE INDICATED	0.006	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) FUEL SUPPLY HEATERS	11.5	NONE INDICATED	0.006	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) RECUPERATOR PRE-HEATERS	12.8	NONE INDICATED	0.006	BACT-PSD
PORT WASHINGTON GENERATING STATION	WASHINGTON CO., WI	10/13/2004	?	GAS HEATER	10.0	NONE INDICATED	0.006	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	FUEL GAS WATER BATH HEATER	13.4	HEATER DESIGN / GOOD OPER PRACTICES	0.007	BACT-PSD
AES RED OAK LLC	MIDDLESEX CO., NJ	10/24/2001	?	FUEL GAS HEATER	16.2	GCP	0.007	LAER
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	4/10/2002	?	(2) EFFICIENCY HEATERS #1,#2	18.5	NONE INDICATED	0.022	BACT-PSD
ENTERGY HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	(2) FUEL PREHEATER	6.5	GCP	0.033	Other Case-by-Case
OCEAN PEAKING POWER	LAKEWOOD, NJ	2002	YES	(3) GAS HEATER	4.6	NONE INDICATED	0.050	LAER

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-21
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas Fuel Heaters
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FUEL PREHEATER	7.0	NONE INDICATED	0.001	BACT
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	3/1/2004	?	DEW POINT HEATER	8.4	NONE INDICATED	0.005	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	FUEL GAS WATER BATH HEATER	13.4	HEATER DESIGN / GOOD OPER PRACTICES	0.006	BACT-PSD
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	4/10/2002	?	(2) EFFICIENCY HEATERS #1,#2	18.5	NONE INDICATED	0.006	BACT-PSD
CRESENT CITY POWER, LLC	ORLEAN CO, LA	6/6/2005	NO	(3) FUEL GAS HEATERS	19.0	NONE INDICATED	0.007	BACT-PSD
ACE ETHANOL- STANLEY	CHIPPEWA, WI	1/21/2004	?	NATURAL GAS BOILER	11.0	NONE INDICATED	0.0075	BACT-PSD
QUAD GRAPHICS	OKLAHOMA	2/3/2004	?	HEATERS	16.0	NONE INDICATED	0.0075	BACT-PSD
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK CO, NY	5/10/2006	NO	FUEL GAS PREHEATER	5.0	LOW SULFUR FUEL	0.0076	BACT-PSD
POWER IOWA ENERGY CENTER	CEDAR RAPIDS, IA	12/20/2002	?	(2) GAS HEATERS (EU3&EU4)	20.0	NONE INDICATED	0.008	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	DEW POINT HEATER	9.0	LOW ASH FUEL	0.008	BACT-PSD
WEPCO PORT WASHINGTON GENERATING STA	WASHINGTON CO, WI	10/13/2004	?	GAS CONDITIONING HEATER	10.0	NONE INDICATED	0.008	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) GAS PREHEATERS	3.08	NATURAL GAS ONLY	0.008	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	(2) NATURAL GAS HEATER STATIONS	0.8	FIRING NATURAL GAS	0.008	BACT
ROQUETTE AMERICA	LEE CO., IA	1/31/2003	?	DEW POINT HEATER	1.6	GCP	0.008	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) FUEL SUPPLY HEATERS	11.5	NONE INDICATED	0.008	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) RECUPERATOR PRE-HEATERS	12.8	NONE INDICATED	0.008	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	FUEL DEW POINT HEATER	3.7	GCP	0.008	BACT
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	NATURAL GAS HEATER	5.0	PROPER COMBUSTION CONTROL	0.009	BACT
ENTERGY HAWKEYE GENERATING, LLC	ADAIR CO., IA	7/23/2002	?	(2) FUEL PREHEATER	6.5	GCP	0.010	BACT-PSD
OCEAN PEAKING POWER	LAKEWOOD, NJ	2002	YES	(3) GAS HEATER	4.6	CLEAN FUELS, NATURAL GAS ONLY	0.011	BACT-PSD
AES RED OAK LLC	MIDDLESEX CO., NJ	10/24/2001	?	FUEL GAS HEATER	16.2	NONE INDICATED	0.027	BACT-PSD
HANDSOME LAKE ENERGY	KENNERDELL, PA	8/4/2003	YES	FUEL HEATER	9.5	NONE INDICATED	0.400	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-22
CPV Valley Energy Center
Recent BACT/LAER Determinations for Natural Gas Fuel Heaters
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	(2) NATURAL GAS HEATER STATIONS	0.8	FIRING NATURAL GAS	0.001	BACT
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FUEL PREHEATER	7.0	NONE INDICATED	0.001	BACT
POWER IOWA ENERGY CENTER	CEDAR RAPIDS, IA	12/20/2002	?	(2) GAS HEATERS (EU3&EU4)	20.0	NONE INDICATED	0.001	BACT-PSD
EMERY GENERATING STATION	CERRO GORDO CO., IA	6/26/2003	?	DEW POINT HEATER	9.0	LOW SULFUR FUEL, NATURAL GAS	0.001	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	FUEL GAS WATER BATH HEATER	13.4	NONE INDICATED	0.001	BACT-PSD
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	3/1/2004	?	DEW POINT HEATER	8.4	NONE INDICATED	0.001	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) FUEL SUPPLY HEATERS	11.5	MAXIMUM SULFUR < 0.6 GRAINS PER 100 SCF	0.002	BACT-PSD
NORTON ENERGY STORAGE, LLC	SUMMIT CO., OH	5/23/2002	YES	(9) RECUPERATOR PRE-HEATERS	12.8	MAXIMUM SULFUR < 0.6 GRAINS PER 100 SCF	0.002	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	FUEL DEW POINT HEATER	3.7	GCP	0.002	BACT
GREATER DES MOINES ENERGY CENTER	DES MOINES, IA	4/10/2002	?	(2) EFFICIENCY HEATERS #1,#2	18.5	NONE INDICATED	0.002	BACT-PSD
OCEAN PEAKING POWER	LAKEWOOD, NJ	2002	YES	(3) GAS HEATER	4.6	NONE INDICATED	0.003	BACT-PSD
AES RED OAK LLC	MIDDLESEX CO., NJ	10/24/2001	?	FUEL GAS HEATER	16.2	NATURAL GAS FUEL	0.004	BACT-PSD
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	NATURAL GAS HEATER	5.0	PIPELINE QUALITY NATURAL GAS	0.005	BACT
HANDSOME LAKE ENERGY	KENNERDELL, PA	8/4/2003	YES	FUEL HEATER	9.5	USE OF NATURAL GAS	4.000	BACT-PSD

GCP = GOOD COMBUSTION PRACTICES

Appendix E - Table E-23
CPV Valley Energy Center
Recent BACT/LAER Determinations for Emergency Diesel Generators
Nitrogen Oxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	Output (KW)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY,KS	10/18/2005	?	EMERGENCY BLACK START GENERATOR	2343	GOOD ENGINE DESIGN IS PROPOSED AS BACT	0.2909	BACT-PSD
DUTCH HARBOR POWER PLANT	ALEUTIANS WEST CENSUS AREA,AK	1/31/2007	NO	I.C. ENGINE	5000	REDUCE NOX BY 90%	0.2915	BACT-PSD
DUTCH HARBOR POWER PLANT	ALEUTIANS WEST CENSUS AREA,AK	1/31/2007	NO	I.C. ENGINE	5000	NONE INDICATED	0.2915	BACT-PSD
USAF EARECKSON AIR STATION	ANCHORAGE, AK	9/29/2003	?	IC ENGINE, DIESEL, (2)	3000	SCR	0.3143	BACT-PSD
ORCHARD PARK GENERATING STATION	FRANKLIN, PA	11/8/2002	?	IC ENGINE, GENERATOR	6030	LEAN BURN, SCR, LOW EMISSION COMBUSTION CONTROL	0.4311	OTHER
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 2	531	NONE INDICATED	0.8572	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	NO	EMERGENCY GENERATOR	1500	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD)	1.2932	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 5	1060	NONE INDICATED	1.3716	BACT-PSD
MAIDSVILLE	MONONGAHELA,WV	3/2/2004	?	EMERGENCY GENERATOR	1343	GOOD COMBUSTION PRACTICES	1.5128	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	NO	FIREWATER PUMP DIESEL ENGINE	391	GCP & DESIGN INCORPORATING TIMING RETARDATION	1.6736	BACT-PSD
MIDAMERICAN ENERGY COMPANY	POTTAWATTAMIE,IA	6/17/2003	?	EMERGENCY GENERATOR	1302	GOOD COMBUSTION PRACTICES	1.7100	BACT-PSD
CITY OF PELLA	MARION, IA	9/25/2002	?	IC ENGINES DIESEL (14)	1918	COMBUSTION AIR CHILLER	1.7100	OTHER
MEDIMMUNE FREDERICK CAMPUS	FREDERICK,MD	1/28/2008	NO	(3) DIESEL FIRED EMERGENCY GENERATORS	2500	NONE INDICATED	1.7416	LAER
BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	WILSON, NC	1/24/2003	?	IC ENGINE, DIESEL GENERATOR (2)	434	IGNITION TIMING RETARD	1.7489	BACT-PSD
DUTCH HARBOR SEAFOOD PROCESSING FACILITY	ALEUTIANS WEST,AK	10/10/2003	?	IC ENGINE, GENERATOR, FUEL OIL, (3)	2220	WATER INJECTION, LOW NOX DESIGN	1.8522	BACT-PSD
PACIFIC BELL	SACREMENTO,CA	2/1/2003	?	IC ENGINES	2189	NONE INDICATED	1.9830	LAER
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIREWATER PUMP DIESEL ENGINES 1-6	1655	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	1.9830	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	NO	FIREWATER PUMP DIESEL ENGINE	492	GCP & DESIGN INCORPORATING TIMING RETARDATION	1.9890	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON, OH	8/14/2003	?	EMERGENCY DIESEL-FIRED GENERATOR	600	LOW SULFUR FUEL, COMBUSTION CONTROL	2.0090	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	BRYAN, OK	3/18/2003	?	IC ENGINES, EMERGENCY GENERATORS (2)	2000	ENGINE DESIGN AND LIMITED HOURS (<500 H/YR)	2.0350	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS, OK	3/21/2003	?	IC ENGINE, BACKUP GENERATOR DIESEL	559	ENGINE DESIGN AND LIMITED HRS (<100 H/YR)	2.1600	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	NO	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	1617	GCP & DESIGN INCORPORATING TIMING RETARDATION	2.2819	BACT-PSD
INGENCO - CHARLES CITY PLANT	CHARLES CITY COUNTY,VA	6/20/2003	?	IC ENGINES, (48)	410	AIR TO FUEL RATIO CONTROL, TURBOCHARGING & CHARGE AIR COOLING SYSTEMS.	2.4000	N/A
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIREWATER PUMP DIESEL ENGINES 1-4	492	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	2.4097	BACT-PSD
SNAKE RIVER POWER PLANT	NOME CENSUS AREA,AK	11/5/2004	?	WARTSILA 12V32B DIESEL ELECTRIC GENERATOR	5211	TIMING RETARD, SEPARATE LOW TEMP COOLING WATER SYSTEM / AFTER COOLER (LT SECTION)	2.4997	BACT-PSD
BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	WILSON, NC	1/24/2003	?	IC ENGINE, DIESEL GENERATOR (2)	1526	IGNITION TIMING RETARD	2.7873	BACT-PSD
SCE&G - JASPER COUNTY GENERATING FACILITY	JASPER, SC	5/23/2002	?	GENERATOR,EMERGENCY DIESEL FUEL	2000	NONE INDICATED	2.8920	BACT-PSD
DUTCH HARBOR POWER PLANT	ALEUTIANS WEST CENSUS AREA,AK	1/31/2007	NO	I.C. ENGINE	5711	FUEL INJECTION TIMING RETARD (FITR) AND AFTERCOOLING (PART OF ENGINE DESIGN)	2.9146	BACT-PSD
DUTCH HARBOR POWER PLANT	ALEUTIANS WEST CENSUS AREA,AK	1/31/2007	NO	I.C. ENGINE	5211	FUEL INJECTION TIMING RETARD AND AFTERCOOLER	2.9146	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY, OK	6/13/2002	?	DIESEL ENGINE, BACKUP GENERATOR	750	ENGINE DESIGN AND LIMITATION OF HOURS	3.0100	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	6/5/2007	NO	EMERGENCY GENERATOR	1750	NONE INDICATED	3.1286	BACT-PSD
REDBUD POWER PLT	OKLAHOMA, OK	5/6/2002	?	DIESEL ENGINE, EMERGENCY GENERATOR	1356	NONE INDICATED	3.1286	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK, IA	4/10/2002	?	EMERGENCY GENERATOR	700	RETARDED INGITION TIMING (3-4 DEGREES)	3.1510	BACT-PSD
FAIRBAULT ENERGY PARK	RICE, MN	7/15/2004	?	IC ENGINE, LARGE, FUEL OIL (1)	500	GOOD COMBUSTION.	3.2800	BACT-PSD
TRIGEN	MERCER, NJ	3/8/2008	NO	DUAL FUEL ENGINES ON 100 % DISTILLATE FUEL OIL	1520	NONE INDICATED	3.4486	RACT
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY,KS	10/18/2005	?	EMERGENCY BLACK START GENERATOR	2343	EMERGENCY DIESEL GENERATORS HAVE NOT BEEN REQUIRED TO INSTALL ADDITIONAL NOX CONTROLS BECAUSE OF INTERMITTENT OPERATION.	3.5187	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH.MN	12/4/2003	?	INTERNAL COMBUSTION ENGINE, LARGE	1380	GOOD COMBUSTION	3.6498	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON, AR	4/1/2002	?	GENERATOR,DIESEL-FIRED	500	GOOD OPERATING PRACTICE	4.0234	BACT-PSD
FIRST QUALITY TISSUE, LLC	CLINTON, PA	10/20/2004	?	FIRE PUMP	429	NONE INDICATED	4.0411	BACT-PSD
STERNE ELECTRIC GENERATING FACILITY	NACOGDOCHES,TX	12/6/2002	?	EMERGENCY GENERATOR	1007	NONE INDICATED	4.0459	BACT-PSD
						GCP, TIMING RETARD		

Appendix E: Table E-24
CPV Valley Energy Center
Recent BACT/LAER Determinations for Emergency Diesel Generators
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	OUTPUT (KW)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CARDINAL FG CO./ CARDINAL GLASS PLANT	BRYAN, OK	3/18/2003	?	IC ENGINES, EMERGENCY GENERATORS (2)	2000	ENGINE DESIGN & LIMIT ON HRS(<500 H/YR)	0.2020	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH.MN	12/4/2003	?	INTERNAL COMBUSTION ENGINE, LARGE	1380	GOOD COMBUSTION	0.2874	BACT-PSD
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY,KS	10/18/2005	?	EMERGENCY BLACK START GENERATOR	2343	GOOD ENGINE DESIGN	0.2909	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY, OK	6/13/2002	?	DIESEL ENGINE, BACKUP GENERATOR	750	ENGINE DESIGN	0.3100	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK, IA	4/10/2002	?	EMERGENCY GENERATOR	700	NONE INDICATED	0.3972	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	N	FIREWATER PUMP DIESEL ENGINE	391	GCP & DESIGN, TIMING RETARDATION	0.3973	BACT-PSD
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	?	DIESEL ENGINES FOR SWITCHING LOCOMOTIVE & FIRE PUMP	1119	GOOD COMBUSTION PRACTICE	0.6100	BACT-PSD
MAIDSVILLE	MONONGAHELA,WV	3/2/2004	?	EMERGENCY GENERATOR	1343	GOOD COMBUSTION PRACTICES	0.6406	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	6/5/2007	N	EMERGENCY GENERATOR	1750	NONE INDICATED	0.7170	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	N	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	1617	GCP & DESIGN, TIMING RETARDATION	0.7360	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	N	EMERGENCY GENERATOR	1500	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFIED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD)	0.7472	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 3	531	NONE INDICATED	0.7501	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 6	1060	NONE INDICATED	0.7501	BACT-PSD
FAIRBAULT ENERGY PARK	RICE, MN	7/15/2004	?	IC ENGINE, LARGE, FUEL OIL (1)	500	GOOD COMBUSTION	0.7600	BACT-PSD
HAWKEYE GENERATING,LLC	ADAIR. IA	7/23/2002	?	EMERGENCY GENERATOR	28	GCP, TIMING RETARD	0.7604	BACT-PSD
SCE&G - JASPER COUNTY GENERATING FACILITY	JASPER, SC	5/23/2002	?	GENERATOR,EMERGENCY DIESEL FUEL	2000	NONE INDICATED	0.7680	BACT-PSD
MIDAMERICAN ENERGY COMPANY	POTTAWATTAMIE,IA	6/17/2003	?	EMERGENCY GENERATOR	1302	GOOD COMBUSTION PRACTICES	0.8500	BACT-PSD
STERNE ELECTRIC GENERATING FACILITY	NACOGDOCHES,TX	12/6/2002	?	EMERGENCY GENERATOR	1007	NONE INDICATED	0.8710	BACT-PSD
GARYVILLE REFINERY	ST. JOHN THE BAPTIST,LA	12/27/2006	?	EMERGENCY GENS (DOCK & TANK FARM) (21-08 & 22-08)		USE OF ULSD	0.8734	BACT-PSD
FIRST QUALITY TISSUE, LLC	CLINTON, PA	10/20/2004	?	FIRE PUMP	429	NONE INDICATED	0.8734	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIREWATER PUMP DIESEL ENGINES 1-7	1655	GOOD ENGINE DESIGN & OPERATING PRACTICES	2.4428	BACT-PSD
PACIFIC BELL	SACREMENTO,CA	2/1/2003	?	IC ENGINES	2189	NONE INDICATED	2.4428	LAER
DUKE ENERGY-JACKSON FACILITY	JACKSON, AR	4/1/2002	?	GENERATOR,DIESEL-FIRED	500	GOOD OPERATING PRACTICE	2.4428	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS, OK	3/21/2003	?	IC ENGINE, BACKUP GENERATOR DIESEL	559	GCP AND ENGINE DESIGN	2.6600	BACT-PSD
INGENCO - CHARLES CITY PLANT	CHARLES CITY COUNTY,VA	6/20/2003	?	IC ENGINES, (48)	410	LIMITING TREATED LANDFILL GAS HEAT INPUT RATIO TO 50% & LANDFILL GAS TRMT SYSTEM	3.3000	OTHER
REDBUD POWER PLT	OKLAHOMA, OK	5/6/2002	?	DIESEL ENGINE, EMERGENCY GENERATOR	1356	ENGINE DESIGN	7.1697	BACT-PSD
		9/26/2007						

Appendix E: Table E-25
CPV Valley Energy Center
Recent BACT/LAER Determinations for Emergency Diesel Generators
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	VOC EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	EMERGENCY GENERATOR	11.4	NONE INDICATED	0.007	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	EMERGENCY GENERATOR	5.2	GCP, TIMING RETARD	0.014	BACT-PSD
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	?	DIESEL GENERATOR SET	14.8	NONE INDICATED	0.033	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	?	EMERGENCY GENERATOR	14.8	GOOD COMBUSTION PRACTICES	0.033	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	0.057	OTHER
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	?	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	GOOD COMBUSTION CONTROL	0.068	LAER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	NO	EMERGENCY GENERATOR	8.0	GOOD COMBUSTION PRACTICES	0.069	LAER
SCE&G - JASPER COUNTY GENERATING FACILITY	COLUMBIA, SC	5/23/2002	?	GENERATOR, EMERGENCY DIESEL FUEL	22.8	NONE INDICATED	0.075	LAER
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	NO	EMERGENCY GENERATOR	16.1	NONE INDICATED	0.083	BACT-PSD
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	NO	EMERGENCY GENERATOR	14.4	GOOD COMBUSTION PRACTICES	0.084	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	0.084	OTHER
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	?	EMERGENCY DIESEL GENERATORS (2)	17.2	NONE INDICATED	0.090	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	EMERGENCY GENERATOR	13.7	GCP	0.090	BACT-PSD
REDBUD POWER PLT PEREZ"	OKLAHOMA	5/6/2002	?	DIESEL ENGINE, EMERGENCY GENERATOR	14.0	ENGINE DESIGN	0.091	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	NO	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	0.091	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	?	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	ENGINE DESIGN, LIMIT OPERATION (<500 H/YR)	0.095	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	1500 KW EMERGENCY GENERATOR	17.3	GOOD COMBUSTION PRACTICES	0.096	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	EMERGENCY GENERATOR	14.1	NONE	0.099	OTHER
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	?	FUEL OIL IC ENGINE GENERATOR	4.9	GOOD COMBUSTION PRACTICES	0.100	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.127	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.127	BACT-PSD
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	?	BACKUP GENERATORS (2)	5.4	NONE INDICATED	0.205	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	NO	EMERGENCY GENERATOR	49.0	GOOD COMBUSTION	0.246	LAER
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	0.257	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	?	DIESEL ENGINE GENERATOR	7.6	ENGINE DESIGN	0.283	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	NORTH CAROLINA	6/30/1999	?	IC ENGINE, EMERGENCY GENERATOR	2.9	LIMITED TO 500 H/YR OF OPERATION	0.295	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	0.324	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	?	EMERGENCY GENERATOR	10.1	GCP, 250 HR/YR	0.334	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	?	(6) BLACK START DIESEL GENERATORS	19.1	GCP, 500 HR/YR	0.353	BACT-PSD
UNION OIL CO. OF CALIFORNIA"	KENAI, AK	8/4/1989	YES	GENERATOR, EMERGENCY DIESEL FIRED	449.0	NONE INDICATED	0.641	BACT-PSD
BRISTOL HOSPITAL, INC."	BRISTOL	10/24/1989	YES	GENERATOR, EMERGENCY DIESEL FIRED	7.1	NONE INDICATED	0.730	BACT-PSD
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	?	1 EMERGENCY GENERATOR	17.1	RETARD TIMING 6 DEGREES	0.959	NSPS

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-26
CPV Valley Energy Center
Recent BACT/LAER Determinations for Emergency Diesel Generators
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	OUTPUT (KW)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SLOAN QUARRY	CLARK COUNTY, NV	12/11/2006	?	LARGE INTERNAL COMBUSTION ENGINE"	160	USE OF LOW-SULFUR DIESEL OIL	0.0030	LAER
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 7	1060	NONE INDICATED	0.0043	BACT-PSD
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	?	DIESEL ENGINES FOR SWITCHING LOCOMOTIVE & FIRE PUMP	1119	LOW SULFUR FUEL - %0.05 BY WEIGHT	0.0160	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	TOMPKINS,NY	3/12/2008	N	EMERGENCY DIESEL GENERATORS (2)	1000	ULTRA LOW SULFUR DIESEL AT 15 PPM S.	0.0185	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	TOMPKINS,NY	3/12/2008	N	EMERGENCY DIESEL GENERATORS (2)	1000	ULTRA LOW SULFUR DIESEL AT 15 PPM S	0.0185	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	TOMPKINS,NY	3/12/2008	N	EMERGENCY DIESEL GENERATORS (2)	1000	ULTRA LOW SULFUR DIESEL AT 15 PPM S	0.0185	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH.MN	12/4/2003	?	INTERNAL COMBUSTION ENGINE, LARGE	1380	GOOD COMBUSTION	0.0201	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH.MN	12/4/2003	?	INTERNAL COMBUSTION ENGINE, LARGE	1380	GOOD COMBUSTION	0.0201	BACT-PSD
PACIFIC BELL	SACREMENTO,CA	2/1/2003	?	IC ENGINES	2189	NONE INDICATED	0.0287	LAER
GENOVA OK I POWER PROJECT	GRADY, OK	6/13/2002	?	DIESEL ENGINE, BACKUP GENERATOR	750	COMBUSTION CONTROL AND GOOD ENGINE DESIGN	0.0330	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	N	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	1617	GCP, GOOD ENGINE DESIGN AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.0415	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	4/14/2005	?	FIRE WATER PUMPS NOS 1 AND 4	531	NONE INDICATED	0.0429	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	N	EMERGENCY GENERATOR	1500	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED	0.0431	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	N	EMERGENCY GENERATOR	1500	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED	0.0431	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	BRYAN, OK	3/18/2003	?	IC ENGINES, EMERGENCY GENERATORS (2)	2000	ENGINE DESIGN	0.0444	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	6/5/2007	N	EMERGENCY GENERATOR	1750	NONE INDICATED	0.0521	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	N	FIREWATER PUMP DIESEL ENGINE	391	GCP, GOOD ENGINE DESIGN, & USE OF LOW SULFUR AND LOW ASH DIESEL	0.0695	BACT-PSD
MAIDSVILLE	MONONGAHELA,WV	3/2/2004	?	EMERGENCY GENERATOR	1343	GOOD COMBUSTION PRACTICES	0.0818	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	6/5/2007	N	EMERGENCY GENERATOR	1750	NONE INDICATED	0.0913	BACT-PSD
SCE&G - JASPER COUNTY GENERATING FACILITY	JASPER, SC	5/23/2002	?	GENERATOR,EMERGENCY DIESEL FUEL	2000	CLEAN FUEL(LOW SULFUR DIESEL), GOOD COMBUSTION PRACTICES	0.0923	BACT-PSD
FAIRBAULT ENERGY PARK	RICE, MN	7/15/2004	?	IC ENGINE, LARGE, FUEL OIL (1)	500	CLEAN FUEL AND GOOD COMBUSTION.	0.1000	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIREWATER PUMP DIESEL ENGINES 1-5	1655	GOOD COMBUSTION PRACTICES	0.1151	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON, OH	8/14/2003	?	EMERGENCY DIESEL-FIRED GENERATOR	600	LOW SULFUR FUEL, COMBUSTION CONTROL	0.1167	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS, OK	3/21/2003	?	IC ENGINE, BACKUP GENERATOR DIESEL	559	COMBUSTION CONTROL AND GOOD ENGINE DESIGN	0.1240	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	8/15/2007	N	FIREWATER PUMP DIESEL ENGINE	492	GCP, GOOD ENGINE DESIGN, & USE OF LOW SULFUR AND LOW ASH DIESEL	0.1264	BACT-PSD
GREATER DES MOINES ENERGY CENTER	POLK, IA	4/10/2002	?	EMERGENCY GENERATOR	700	NONE INDICATED	0.1319	OTHER
MIDAMERICAN ENERGY COMPANY	POTTAWATTAMIE,IA	6/17/2003	?	EMERGENCY GENERATOR	1302	GOOD COMBUSTION PRACTICES	0.1400	BACT-PSD
MIDAMERICAN ENERGY COMPANY	POTTAWATTAMIE,IA	6/17/2003	?	EMERGENCY GENERATOR	1302	GOOD COMBUSTION PRACTICES	0.1400	BACT-PSD
INGENCO - CHARLES CITY PLANT	CHARLES CITY COUNTY,VA	6/20/2003	?	IC ENGINES, (48)	410	GOOD COMBUSTION PRACTICES.	0.2000	N/A
INGENCO - CHARLES CITY PLANT	CHARLES CITY COUNTY,VA	6/20/2003	?	IC ENGINES, (48)	410	GOOD COMBUSTION PRACTICES	0.2000	N/A
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIREWATER PUMP DIESEL ENGINES 1-3	492	GOOD COMBUSTION PRACTICES	0.2449	BACT-PSD
GARYVILLE REFINERY	ST. JOHN THE BAPTIST,LA	12/27/2006	?	EMERGENCY GENS (DOCK & TANK FARM) (21-08 & 22-08)		USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.2868	BACT-PSD
STERNE ELECTRIC GENERATING FACILITY	NACOGDOCHES,TX	12/6/2002	?	EMERGENCY GENERATOR	1007	NONE INDICATED	0.2868	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	JACKSON, AR	4/1/2002	?	GENERATOR,DIESEL-FIRED	500	GOOD OPERATING PRACTICE	0.2914	BACT-PSD
HAWKEYE GENERATING,LLC	ADAIR. IA	7/23/2002	?	EMERGENCY GENERATOR	28	GCP, TIMING RETARD	1.1751	BACT-PSD
HAWKEYE GENERATING,LLC	ADAIR. IA	7/23/2002	?	EMERGENCY GENERATOR	28	GCP, TIMING RETARD	1.1751	BACT-PSD
SNAKE RIVER POWER PLANT	NOME CENSUS AREA,AK	11/5/2004	?	WARTSILA 12V32B DIESEL ELECTRIC GENERATOR	5211	GOOD COMBUSTION PRACTICES	3.8429	BACT-PSD
INGENCO K&O FACILITY	BRUNSWICK, VA	9/26/2007	N	ELECTRIC GENERATION	410	GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES	6.2717	N/A
								N/A

Appendix E: Table E-27
CPV Valley Energy Center
Recent BACT/LAER Determinations for Emergency Diesel Generators
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	OUTPUT (KW)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CORNELL COMBINED HEAT & POWER PROJECT	TOMPKINS,NY	3/12/2008	?	EMERGENCY DIESEL GENERATORS (2)	1000	ULTRA LOW SULFUR DIESEL AT 15 PPM S	0.0002	BACT-PSD
SCE&G - JASPER COUNTY GENERATING FACILITY	JASPER, SC	5/23/2002	?	GENERATOR,EMERGENCY DIESEL FUEL	2000	LOW SULFUR (0.05%) DIESEL	0.0437	BACT-PSD
PACIFIC BELL	SACREMENTO,CA	2/1/2003	?	IC ENGINES	2189		0.0460	LAER
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	?	EMERGENCY GENERATOR	1500	LOW-SULFUR DIESEL 0.05% BY WT OR LESS NOT TO EXCEED NSPS RQMT	0.0489	BACT-PSD
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY,KS	10/18/2005	?	EMERGENCY BLACK START GENERATOR	2343	GOOD COMBUSTION CONTROL	0.0498	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	BRYAN, OK	3/18/2003	?	IC ENGINES, EMERGENCY GENERATORS (2)	2000	LOW SULFUR FUEL, < 0.05% S	0.0500	BACT-PSD
FAIRBAULT ENERGY PARK	RICE, MN	7/15/2004	?	IC ENGINE, LARGE, FUEL OIL (1)	500	LOW SULFUR FUEL.	0.0510	BACT-PSD
MIDAMERICAN ENERGY COMPANY	POTTAWATTAMIE,IA	6/17/2003	?	EMERGENCY GENERATOR	1302	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	0.0520	BACT-PSD
FAIRBAULT ENERGY PARK	RICE,MN	6/5/2007	?	EMERGENCY GENERATOR	1750		0.0521	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS, OK	3/21/2003	?	IC ENGINE, BACKUP GENERATOR DIESEL	559	USE OF LOW SULFUR DIESEL FUEL (< 0.05% S BY WT)	0.0522	BACT-PSD
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	?	DIESEL ENGINES FOR SWITCHING LOCOMOTIVE & FIRE PUMP	1119	LOW SULFUR FUEL. LESS TAN 0.05 BY WHEIGHT	0.0600	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	WASHINGTON, OH	8/14/2003	?	EMERGENCY DIESEL-FIRED GENERATOR	600	LOW SULFUR FUEL, COMBUSTION CONTROL	0.0648	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH.MN	12/4/2003	?	INTERNAL COMBUSTION ENGINE, LARGE	1380	LOW SULFUR FUEL	0.1696	BACT-PSD
STERNE ELECTRIC GENERATING FACILITY	NACOGDOCHES,TX	12/6/2002	?	EMERGENCY GENERATOR	1007	DISTILLATE FUEL OIL CONTAINING NO MORE THAN 0.2 WT% SULFUR.	0.2675	BACT-PSD
REDBUD POWER PLT	OKLAHOMA, OK	5/6/2002	?	DIESEL ENGINE, EMERGENCY GENERATOR	1356		0.4000	BACT-PSD
MAIDSVILLE	MONONGAHELA,WV	3/2/2004	?	EMERGENCY GENERATOR	1343	SULFUR CONTENT IN THE FUEL LIMITED TO 0.05% BY WEIGHT	0.4705	BACT-PSD
INGENCO - CHARLES CITY PLANT	CHARLES CITY COUNTY,VA	6/20/2003	?	IC ENGINES, (48)	410	GOOD COMBUSTION PRACTICES	0.5000	RACT
INGENCO K&O FACILITY	BRUNSWICK, VA	9/26/2007	?	ELECTRIC GENERATION	410	GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES	1.6613	N/A
BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	WILSON, NC	1/24/2003	?	IC ENGINE, DIESEL GENERATOR (2)	1526		2.3000	Other Case-by-Case
BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	WILSON, NC	1/24/2003	?	IC ENGINE, DIESEL GENERATOR (2)	434		2.3000	Other Case-by-Case

Appendix E - Table E-28
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 2	5.46	NONE INDICATED	0.860	N/A
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	NO	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	1.200	Other Case-by-Case
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	?	DIESEL FIRE PUMP	1.30	LEAN BURN ENGINE	1.300	BACT-OTHER
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 5	10.90	NONE INDICATED	1.370	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	1.571	LAER
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	4.20	GCP AND DESIGN, TIMING RETARDATION	1.674	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	DIESEL FIRE PUMP	1.10	NONE INDICATED	1.850	LAER
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	1.850	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	?	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	RETARD ENGINE TIMING; TURBOCHARGER AFTERCOOLINC	1.852	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-6	17.76	GOOD DESIGN & PROPER OPERATING PRACTICES	1.983	BACT-PSD
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	?	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	1.984	LAER
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	5.28	GCP AND DESIGN, TIMING RETARDATION	1.989	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	FIRE PUMP	1.82	GCP, TIMING RETARD	2.088	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	DIESEL FIRE PUMP	1.50	< 100 HR/YR OPERATION	2.200	N/A
VAUGHAN FURNITURE COMPANY	STUART, VA	8/28/1996	YES	DIESEL FIRE PUMP (IC ENGINE)	1.85	300 HOURS/YEAR LIMIT	2.381	BACT
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-4	5.28	GOOD DESIGN & PROPER OPERATING PRACTICES	2.410	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	2.514	BACT
DUKE ENERGY - AUDRAIN GENERATING STATION	VANDALIA, MO	5/9/2000	YES	EMERGENCY DIESEL FIRE PUMP	1.50	WATER SPRAY INJECTION SYSTEM	2.563	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	FIRE WATER PUMP	2.40	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	2.700	LAER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	YES	(2) FIRE PUMP DIESEL ENGINE	3.20	LIMIT OPERATING HOURS	2.750	OTHER
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	NO	FIRE WATER PUMP	2.03	NONE INDICATED	2.819	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	FIRE WATER PUMP	3.11	GOOD WORKING ORDER & OPER PER MFGR SPECS	2.966	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	3.200	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	3.440	BACT-OTHER
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	3.800	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	3.868	BACT-PSD
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	3.873	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	3.875	BACT
BELL ENERGY FACILITY	TEMPLE	6/26/2001	NO	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL	3.875	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	NO	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	3.875	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	?	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	3.875	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	3.876	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	3.881	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.40	NONE INDICATED	3.886	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	3.894	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	3.894	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	EMERGENCY DIESEL FIRE PUMP ENGINE	3.20	LOW SULFUR FUEL COMBUSTION CONTROL	4.000	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	4.000	BACT-OTHER
FIRST QUALITY TISSUE, LLC	CLINTON, PA	3/10/2005	?	FIRE PUMP	4.60	NONE INDICATED	4.040	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	?	FIRE PUMP	1.50	NONE INDICATED	4.250	BACT-OTHER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	4.339	LAER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	IGNITION TIMING RETARD	4.410	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.89	GCP	4.410	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	4.410	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.00	ENGINE DESIGN AND LIMITATION OF HOURS	4.410	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	FIRE WATER PUMP DIESEL ENGINE	1.60	ENGINE DESIGN AND LIMITATION OF HOURS	4.410	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	FIRE WATER PUMP (IC ENGINE)	2.12	ENGINE DESIGN AND HOURS LIMIT (<100 H/YR)	4.410	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP EQUIPMENT USAGE LIMITS	4.411	BACT-PSD
LAKEWAOOD COGENERATION, LP	LAKEWOOD, NJ	1993	YES	DF FIRE PUMP	2.6	NONE INDICATED	4.423	BACT-OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.50	NONE INDICATED	4.429	OTHER
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	DIESEL EMERGENCY FIRE WATER PUMP	2.30	OPERATION LIMITED TO < 500 HR/YR	4.435	BACT-OTHER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	YES	(2) FIRE PUMP DIESEL ENGINE	2.20	LIMIT OPERATING HOURS	4.727	OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	5.000	BACT
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	NO	FIRE PUMP ENGINE	2.07	NONE INDICATED	5.081	BACT-PSD
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	?	EMERGENCY FIRE PUMP	0.92	LIMITED TO 1,128 GAL/YR DIESEL FUEL	7.750	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	29.800	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDEI

GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-29
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	5.28	GCP AND DESIGN, TIMING RETARD	0.0593	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	0.069	BACT
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-3	5.28	GOOD ENGINE DESIGN & PROPER OPERATING PRACTICES	0.1086	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	0.180	BACT-OTHER
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	NO	FIRE WATER PUMP	2.03	NONE INDICATED	0.312	BACT-OTHER
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	?	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	0.331	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	4.20	GCP AND DESIGN, TIMING RETARD	0.3973	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	DIESEL FIRE PUMP	1.10	NONE INDICATED	0.400	BACT
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	NO	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	0.527	Other Case-by-Case
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	0.611	BACT
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	FIRE WATER PUMP	3.11	GOOD WORKING ORDER / OPER PER MFGR SPECS.	0.618	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	FIRE WATER PUMP	2.40	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	0.635	BACT
DUKE ENERGY - AUDRAIN GENERATING STATION	VANDALIA, MO	5/9/2000	YES	EMERGENCY DIESEL FIRE PUMP	1.50	GOOD COMBUSTION	0.689	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	?	DIESEL FIRE PUMP	1.30	COMBUSTION CONTROL	0.710	BACT-OTHER
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	0.750	BACT-OTHER
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 3	5.46	NONE INDICATED	0.750	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 6	10.90	NONE INDICATED	0.750	BACT-PSD
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	YES	(2) FIRE PUMP DIESEL ENGINE	2.20	NONE INDICATED	0.773	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.800	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	DIESEL FIRE PUMP	1.50	< 100 HR/YR OPERATION	0.800	N/A
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.817	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.817	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	0.821	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.833	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	NO	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.833	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	?	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	0.833	Other Case-by-Case
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.834	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.835	BACT
BELL ENERGY FACILITY	TEMPLE	6/26/2001	NO	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL	0.844	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	0.849	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.850	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.40	ENGINE DESIGN	0.854	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	EMERGENCY DIESEL FIRE PUMP ENGINE	3.20	LOW SULFUR FUEL COMBUSTION CONTROL	0.863	BACT-PSD
FIRST QUALITY TISSUE, LLC	CLINTON, PA	3/10/2005	?	FIRE PUMP	4.60	NONE INDICATED	0.8734	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	0.933	BACT
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.50	NONE INDICATED	0.943	OTHER
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	YES	DF FIRE PUMP	2.6	NONE INDICATED	0.946	BACT-OTHER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	GCP	0.950	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.89	GCP	0.950	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	0.950	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.00	GCP AND DESIGN	0.950	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	FIRE WATER PUMP DIESEL ENGINE	1.60	GOOD ENGINE DESIGN	0.950	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	0.950	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	FIRE WATER PUMP (IC ENGINE)	2.12	ENGINE DESIGN AND GCP	0.950	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP EQUIPMENT USAGE LIMITS	0.950	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	DIESEL EMERGENCY FIRE WATER PUMP	2.30	OPERATION LIMITED TO < 500 HR/YR	0.957	BACT-OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	1.059	BACT
NORTHSTAR DEVELOPMENT PROJECT	ALASKA	2/5/1999	?	FIRE WATER PUMP	6.04	NONE INDICATED	1.060	BACT-PSD
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	?	EMERGENCY FIRE PUMP	0.92	LIMITED TO 1,128 GAL/YR DIESEL FUEL	1.674	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	NO	FIRE PUMP ENGINE	2.07	NONE INDICATED	2.144	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-7	17.76	GOOD ENGINE DESIGN & PROPER OPERATING PRACTICES	2.4428	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	FIRE PUMP	1.82	GCP, TIMING RETARD	2.582	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	?	FIRE PUMP	1.50	NONE INDICATED	2.880	BACT-OTHER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	YES	(2) FIRE PUMP DIESEL ENGINE	3.20	NONE INDICATED	3.719	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-30
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Volatile Organic Compounds Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	VOC EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	?	FIRE WATER PUMP	5.28	GOOD COMBUSTION PRACTICES	0.0133	BACT-PSD
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	NO	DIESEL FIRED WATER PUMP	3.40	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.0147	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	0.0220	LAER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	0.0333	BACT
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	NO	FIRE WATER PUMP	2.03	NONE INDICATED	0.0477	BACT-OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	NO	DIESEL ENGINE FIRE PUMP	1.70	GOOD COMBUSTION PRACTICES	0.0480	LAER
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	?	FIRE PUMP	1.50	NONE INDICATED	0.0550	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	0.0611	BACT
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	DIESEL FIRE PUMP	1.50	<= 100 HR/YR OPERATION	0.0700	N/A
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	?	EMERGENCY DIESEL FIRE PUMP	1.60	NONE INDICATED	0.0875	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.0912	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	DIESEL FIRE PUMP	1.10	NONE INDICATED	0.1000	LAER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	0.1100	BACT-OTHER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	?	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	0.1295	LAER
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	NO	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	0.1400	Other Case-by-Case
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	FIRE WATER PUMP	3.11	GOOD WORKING ORDER / OPERATION PER MFGR SPECS.	0.2472	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	0.2500	BACT-OTHER
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	?	BACKUP DIESEL FIRE PUMP	1.40	NONE INDICATED	0.2857	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	FIRE PUMP	1.82	GCP, TIMING RETARD	0.2967	BACT-OTHER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	0.2985	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.3000	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.3090	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	NO	FIRE PUMP ENGINE	2.07	NONE INDICATED	0.3097	BACT-PSD
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.3098	BACT
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	0.3113	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.40	ENGINE DESIGN	0.3125	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	NO	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL	0.3125	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.3125	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	NO	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.3125	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.3125	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	?	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	0.3125	Other Case-by-Case
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.3302	BACT
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	FIRE WATER PUMP (IC ENGINE)	2.12	ENGINE DESIGN	0.3302	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.50	NONE INDICATED	0.3429	OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.89	GCP	0.3500	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	0.3500	BACT-PSD
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	?	DIESEL FIRE PUMP	2.17	NONE	0.355	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	GCP	0.3600	BACT-OTHER
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	0.3600	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.00	COMBUSTION PRACTICES AND DESIGN	0.3600	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP, EQUIPMENT USAGE LIMITS	0.3605	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	YES	DF FIRE PUMP	2.60	NONE INDICATED	0.3615	BACT-OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	0.3824	BACT
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	?	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	FUEL SELECTION; GOOD COMBUSTION	0.7037	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.7100	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	?	DIESEL FIRE PUMP	0.95	GCP, 500 HR/YR	0.9739	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-31
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 7	10.90	NONE INDICATED	0.004	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	0.019	BACT
EL PASO MANATEE ENEREGY CENTER	MANATTE CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	?	FIRE WATER PUMP DIESEL ENGINE	1.60	ENGINE DESIGN AND GOOD COMBUSTION	0.031	BACT-PSD
ARIZONA CLEAN FUELS YUMA	YUMA, AZ	8/25/2006	?	FIRE WATER PUMPS NOS 1 AND 4	5.46	NONE INDICATED	0.040	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	0.044	BACT
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	FIRE WATER PUMP	2.40	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	0.047	BACT
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	0.060	BACT-OTHER
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	?	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	0.061	BACT-PSD
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	NO	FIRE WATER PUMP	2.03	NONE INDICATED	0.062	BACT-OTHER
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	4.20	GCP AND DESIGN,USE OF LOW SULFUR AND LOW ASH DIESEL	0.070	BACT-PSD
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	NO	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	0.070	Other Case-by-Case
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.100	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP USE OF FUEL < 0.05% S BY WT. EQUIPMENT USAGE LIMIT	0.100	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-5	17.76	GOOD COMBUSTION PRACTICES	0.115	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	0.120	BACT
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	0.120	BACT
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	FIRE PUMP	1.82	GCP, TIMING RETARD	0.121	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	YES	FIRE PUMP	1.82	GCP, TIMING RETARD	0.121	BACT-PSD
CREOLE TRAIL LNG IMPORT TERMINAL	CAMERON, LA	4/22/2008	?	FIREWATER PUMP DIESEL ENGINE	5.28	GCP AND DESIGN,USE OF LOW SULFUR AND LOW ASH DIESEL	0.126	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	DIESEL FIRE PUMP	1.50	SULFUR <= 0.2% BY WEIGHT; <= 100 HR/YR OPERATION	0.170	N/A
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	?	FIRE PUMP	1.50	FUEL SPECIFICATION: SULFUR CONTENT </= 0.15% BY WT	0.200	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	?	FIRE PUMP	1.50	FUEL SPECIFICATION: SULFUR CONTENT </= 0.15% BY WT	0.200	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	FIRE WATER PUMP	3.11	GOOD WORKING ORDER AND OPERATION PER MFGR SPECS	0.210	BACT-PSD
SABINE PASS LNG IMPORT TERMINAL	CAMERON, LA	5/9/2007	?	FIREWATER PUMP DIESEL ENGINES 1-3	5.28	GOOD COMBUSTION PRACTICES	0.245	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES, S < 0.05% (< 500 HR/YR)	0.250	BACT-OTHER
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	?	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	FUEL SELECTION; GOOD COMBUSTION	0.259	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.260	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.260	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	0.261	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	NO	FIRE PUMP ENGINE	2.07	NONE INDICATED	0.271	BACT-PSD
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.274	BACT
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.274	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.274	BACT-PSD
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.274	BACT
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	EMERGENCY DIESEL FIRE PUMP ENGINE	3.20	LOW SULFUR FUEL COMBUSTION CONTROL	0.275	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.4	NONE INDICATED	0.275	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	NO	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.275	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	?	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	0.275	Other Case-by-Case
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.276	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	NO	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL AND USE OF LOW-SULFUR DIESEL	0.281	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.300	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	YES	DF FIRE PUMP	2.60	NONE INDICATED	0.308	BACT-OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	DIESEL FIRE PUMP	1.10	NONE INDICATED	0.310	BACT
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	LOW ASH FUEL AND GOOD OPERATING PRACTICES	0.310	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.89	GCP	0.310	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	FIRE WATER PUMP (IC ENGINE)	2.12	COMBUSTION CONTROL AND GOOD ENGINE DESIGN	0.310	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	LOW ASH FUEL AND GCP	0.310	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.89	GCP	0.310	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	0.310	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.00	LOW ASH FUEL	0.310	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	0.311	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.50	NONE	0.314	OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.50	NONE	0.314	OTHER
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	?	EMERGENCY FIRE PUMP	0.92	NONE INDICATED	0.543	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	?	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	2.110	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDEI
GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-32
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	SO_2 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	DIESEL FIRE PUMP	1.1	NONE INDICATED	0.020	BACT
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	?	DIESEL FIRED EMERGENCY PUMP	2.2	LIMITED OPERATION < 500 HR/YR	0.047	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	FIRE WATER PUMP	2.1	LOW SULFUR FUEL	0.047	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	FIRE PUMP ENGINE	2.9	LOW SULFUR FUEL OIL (< 0.05% S)	0.048	BACT
LA COUNTY PROBATION/FAC PLANNING/ISD	LOS ANGELES, CA	8/14/2003	YES	IC ENGINE FIRE PUMP	1.9	LOW SULFUR FUEL OIL (TO BE CONVERTED TO ULTRA LOW S FUEL)	0.050	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.5	LIMITED TO 500 H/YR OF OPERATION	0.050	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	DIESEL FIRE PUMP	1.5	SULFUR MUST BE <= 0.2% BY WEIGHT; <= 100 HR/YR OPERATION	0.050	N/A
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.0	LOW SULFUR DIESEL FUEL	0.050	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.4	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.051	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	EMERGENCY DIESEL FIRE PUMP	2.1	LIMITED TO 200 H/YR OPERATION	0.051	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	?	DIESEL FIRE PUMP	3.9	GCP AND LOW SULFUR FUEL	0.052	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	DIESEL FIRE PUMP ENGINE	1.5	NONE INDICATED	0.053	BACT-PSD
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	?	FIRE PUMP	3.4	LOW SULFUR FUEL AND LIMITED OPERATION	0.059	BACT
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	NO	DIESEL ENGINE FIRE PUMP	12.0	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.060	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.101	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.101	BACT-PSD
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	NO	DIESEL FIRED WATER PUMP	3.4	NONE INDICATED	0.180	BACT-PSD
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	NO	DIESEL ENGINE FIRE PUMP	1.7	LOW SULFUR FUEL	0.203	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	?	FIRE WATER PUMP (IC ENGINE)	2.1	USE OF VERY LOW SULFUR DIESEL FUEL (<0.05% S BY WT)	0.236	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	NO	FIREWATER PUMP ENGINE	3.2	GOOD COMBUSTION CONTROLS, USE OF LOW SULFUR (0.05%) FUELS	0.250	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	DIESEL FIREWATER PUMP ENGINE	1.6	GOOD COMB CONTROL / MODERN ENGINES, S < 0.05% (< 500 HR/YR)	0.250	BACT-OTHER
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.1	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.255	BACT
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.7	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.255	BACT
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	NO	FIREWATER PUMP ENGINE	2.4	DISTILLATE FUEL OIL < 0.3 WEIGHT PERCENT SULFUR	0.258	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	?	(2) FIRE WATER PUMPS	2.4	DIESEL </+ 0.3% S, MAX OPER 100 H/YR, NON-EMERGENCY USE	0.258	Other Case-by-Case
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	FIRE WATER PUMP ENGINE	2.7	NONE INDICATED	0.261	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	EMERGENCY DIESEL FIRE PUMP ENGINE	3.2	LOW SULFUR FUEL COMBUSTION CONTROL	0.263	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	DIESEL FIRE PUMP	1.8	LOWE SULFUR FUEL AND LIMITED OPERATION	0.283	BACT
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	?	BACKUP DIESEL FIRE PUMP	1.4	NONE INDICATED	0.286	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	DIESEL FIRE PUMP	3.5	NONE INDICATED	0.286	BACT-OTHER
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	YES	DF FIRE PUMP	2.6	NONE INDICATED	0.288	BACT-OTHER
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	EMERGENCY DIESEL FIRE PUMP ENGINE	3.8	DIESEL FUEL SULFUR CONTENT OF 0.05% & EQUIPMENT USAGE LIMITS	0.289	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	EMERGENCY FIRE PUMP (IC ENGINE)	2.6	LOW SULFUR FUEL	0.290	BACT-OTHER
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	NO	DIESEL-FIRED FIRE PUMP	2.3	GCP, INLET AIR FILTER	0.322	BACT
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	FIRE WATER PUMP	3.1	GOOD WORKING ORDER AND OPERATION PER MANUFACTURER SPECS.	0.371	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	?	FIRE WATER PUMP DIESEL ENGINE	2.4	NONE INDICATED	0.400	BACT-PSD
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	NO	EMERGENCY FIREWATER PUMP	2.0	NONE INDICATED	0.420	Other Case-by-Case
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	?	EMERGENCY DIESEL FIRE PUMP	1.6	LOW SULFUR FUEL	0.500	BACT-PSD
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	NO	FIRE WATER PUMP	2.0	NONE INDICATED	0.507	BACT-OTHER
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	?	DIESEL FIRE PUMP	1.0	SULFUR LIMITED TO 0.05% BY WEIGHT, 500 HR/YR	0.794	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	NO	FIRE PUMP ENGINE	2.1	NONE INDICATED	1.597	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Appendix E: Table E-33
CPV Valley Energy Center
Recent BACT/LAER Determinations for Diesel Fire Pumps
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	HEAT INPUT (MMBTU/HR)	CONTROL DESCRIPTION	H2SO4 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.0017	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	?	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	FUEL SELECTION	0.0017	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	?	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.0038	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	?	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.0144	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	NO	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.0144	BACT-PSD
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.0380	BACT
WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	NO	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.0392	BACT

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

APPENDIX F

CONTROL COST ANALYSES

Appendix F: Table F-1
CPV Valley Energy Center
BACT Economic Impact Analysis
Auxiliary Boiler CO Control

DIRECT CAPITAL COSTS	
Purchased Equipment Costs (PEC)	
CO Catalyst System	$200,000
Direct Installation Costs	
Instrumentation Cost (10% of PEC)	$20,000
Taxes	N/A
Freight (5% of PEC)	$10,000
TOTAL DIRECT CAPITAL COSTS (TDC)	**$230,000**
INDIRECT COSTS	
General Facilities (5% of TDC)	$11,500
Engineering and Home Office Fees (10% of TDC)	$23,000
Start-up (2% of TDC)	$4,600
Performance Testing (1% of TDC)	$2,300
Contingencies (3% of TDC)	$6,900
TOTAL INDIRECT CAPITAL COSTS (TIC)	**$48,300**
TOTAL CAPITAL INVESTMENT (TCI)	**$278,300**
DIRECT ANNUAL COSTS	
Operating Labor ($25/hr*.25hr/shift*2000hr/yr*shift/8hr)	$1,563
Supervisory Labor (15% of Operating Labor)	$234
Maintenance Labor ($13/hr*.25hr/shift*2000hr/yr*shift/8hr)	$813
Maintenance Materials (100% of Maintenance Labor)	$813
Catalyst Replacement Cost ($90,000/3 year service life)	$30,000
TOTAL DIRECT ANNUAL COSTS	**$33,422**
INDIRECT ANNUAL COSTS	
Overhead (60% of sum of Operating Labor & Maintenance Labor & Cost)	$19,913
Property Tax (1% of TCI)	$2,783
Insurance (1% of TCI)	$2,783
Administration (2% of TCI)	$5,566
TOTAL INDIRECT ANNUAL COSTS	**$31,045**
TOTAL ANNUAL COSTS	**$64,466**
CAPITAL RECOVERY FACTOR, CRF = $(i * (1+i)^n)/((1+i)^n - 1)$	0.1490
Equipment Life (years) 10	
Interest Rate 8.0%	
TOTAL CAPITAL REQUIREMENT	$278,300
TOTAL ANNUALIZED CAPITAL REQUIREMENT	**$41,475**
TOTAL ANNUALIZED COST (Total annual cost and annualized capital cost)	**$105,941**
BASELINE UNCONTROLLED POTENTIAL CO EMISSIONS (TPY)	
Boiler CO Emission Rate (tons/yr based on 2,000 hrs/yr)	**3.70**
Oxidation Catalyst Control Efficiency 90%	
Annual Amount of CO Controlled by Oxidation Catalyst (tons/yr)	**3.33**
COST-EFFECTIVENESS ($ per ton of CO removed)	**$31,814**

APPENDIX G

REVISED AIR QUALITY MODELING PROTOCOL

AIR QUALITY MODELING PROTOCOL (REVISED)

For CPV Valley Energy Center

Wawayanda, New York

TRC Project Number: 150338.000006.000000

Prepared For:

CPV Valley LLC

Prepared By:

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November 2008

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APPENDICES

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1.0 INTRODUCTION

This revised air quality modeling protocol for the CPV Valley Energy Center describes the techniques and analytical procedures that are proposed for completing air quality modeling analyses that will be submitted to support air permit applications and Environmental Impact Statement (EIS) reports. A prior modeling protocol was submitted to the U.S. Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC) in September 2008. The revised protocol incorporates subsequent project design changes and also addresses comments received from EPA and NYSDEC.

CPV Valley LLC is proposing to construct and operate a 630 megawatt (MW) combined cycle electric power generating facility to be known as the CPV Valley Energy Center (hereafter referred to as Project or Facility) in the Town of Wawayanda, New York. The Project will include two combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), one steam turbine generator (STG), and other ancillary equipment. Sources of potential emissions to the air from the Project include the combustion turbines (CTs) and HRSGs, which will collectively be referred to as the combined cycle units; an auxiliary boiler; an emergency diesel generator; a diesel fire water pump, and two small fuel gas heaters.

Exhaust steam from the STG will be condensed and cooled using an air-cooled condenser, and the resulting water will be returned to the HRSG for reuse. Air-cooled condensing will be used to minimize water use and to avoid the emissions and impacts associated with cooling tower plumes. The air-cooled condensers will not be a source of emissions to the air.

The CTs will be fired primarily with natural gas. Backup use of ultra-low sulfur diesel oil (ULSD) with a sulfur content equal to or less than 15 parts per million (ppm) by weight is also proposed in the CTs. The use of ULSD in the CTs will be limited on an annual basis and is designed to increase reliability of the electrical distribution system if natural gas supplies are needed to meet residential heating or other demands or otherwise interrupted. The HRSGs will incorporate supplementary duct firing with natural gas. Emissions of nitrogen oxides (NO_x) from the combined cycle units will be controlled by the use of a Selective Catalytic Reduction (SCR) system. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) from the combined cycle units will be controlled by an oxidation catalyst system. The auxiliary boiler will fire natural gas. The emergency generator and the fire water pump will fire ULSD. The fuel gas heaters will fire natural gas exclusively.

Potential to emit for the Project will exceed 100 tons per year (tpy) for NO_x and CO. The Project will be proposing an enforceable emissions cap on particulate matter (PM), including PM with an aerodynamic diameter of 10 microns or less (PM_{10}) and of 2.5 microns or less ($PM_{2.5}$) along with associated recordkeeping and reporting measures in its air permit application to limit emissions of PM to 95 tpy on a rolling 12-month basis. Based on the Project potential to emit, it is anticipated that a Prevention of Significant Deterioration (PSD) permit will be required from EPA and that a preconstruction major source permit will be required from the New York State Department of Environmental Conservation (NYSDEC).

Potential to emit for the Project will also exceed the applicable major source thresholds for nonattainment new source review (NNSR) in ozone nonattainment for NO_x (100 tpy) and ozone (50 tpy). However, as mentioned previously, an enforceable emissions cap for PM equal to 95 tpy will be proposed to limit Project emissions to less than the NNSR major source threshold for $PM_{2.5}$ (100 tpy). It is anticipated that any major source NNSR requirements (and PSD requirements) will be incorporated in the state air facility permit that will be issued by NYSDEC.

Potential to emit for hazardous air pollutants (HAP) will be below applicable major source thresholds of 25 tpy for total HAP and 10 tpy for each individual HAP.

This modeling protocol has been prepared to describe the techniques that are proposed for completing the air quality modeling analyses that will be required to demonstrate that the Project will comply with requirements related to ambient impacts, such as compliance with ambient air quality standards, PSD increments, and state ambient guideline concentrations for air toxics. The proposed modeling procedures are intended to be consistent with guidance provided by EPA in the "Guideline on Air Quality Models" which appears in the Code of Federal Regulations (CFR) at Appendix W of 40 CFR Part 51) and by NYSDEC in "NYSDEC Guidelines on Dispersion Modeling Procedures for Air Quality Impact Analysis" (DAR-10).

2.0 FACILITY DESCRIPTION AND SOURCES

The information in this section provides an overview of the Project location, proposed equipment and operations, and the associated stack parameters and emission rates that will be modeled for the proposed Project.

2.1 Site Location and Surroundings

The Project will be located within an approximately 15-acre site located within a larger 122-acre parcel. The site is located in the northeast portion of the Town of Wawayanda near the boundary with the City of Middletown. The parcel is located north of Interstate Route 84, east of New York Route 17M, and south and west of New York Route 6.

The site is currently undeveloped land consisting of tracts previously used for agricultural purposes and wooded areas. Topography in the immediate area generally slopes downward from Route 6 on the north to Interstate 84 on the south. Typical terrain elevations on the Project site are in the range of 450 to 460 feet above mean sea level (MSL).

The Project location and surroundings are depicted in Figure 2-1, a base map showing portions of the 7.5 minute U. S. Geological Survey (USGS) topographic quadrangle for Middletown. An aerial photograph of the Project site appears as Figure 2-2. In each figure, the outline of the larger 122-acre parcel is delineated.

The Project site is located within a broad valley with an axis oriented roughly south-southwest to north-northeast. A well-defined ridge with typical peak elevations on the order of 350 meters (approximately 1150 feet (ft)) MSL is located approximately 11.5 kilometers (km) to the west-northwest and has the same orientation. Some higher terrain elevations occur on more northerly portions of this ridge. Smaller hills and ridges with a similar orientation occur to the west-northwest within a few km of the Project site.

Figure 2-3 depicts the terrain surrounding the Project location and clearly shows the well defined ridge to the west-northwest and a broader area of high terrain located beyond this ridge. Elevated terrain representing the eastern edge of the valley is apparent at greater distances from the Project site. Figure 2-3 also shows the location of the Project site, Orange County Airport (MGJ), and Stewart International Airport (SWF). The Hudson River runs north to south and is located approximately 35 km to the east. The nearest portion of Long Island Sound is located approximately 80 km to the southeast.

2.2 Air Quality Status Designations

The EPA has established National Ambient Air Quality Standards (NAAQS) for each of the following criteria air pollutants: PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), CO, and lead (Pb).

Areas in which the NAAQS are being met are referred to as attainment areas. Areas in which the NAAQS are not being met are referred to as nonattainment areas. Areas that were formerly nonattainment areas but are now in attainment and covered by a maintenance plan are referred to as maintenance areas. Areas for which sufficient data are not available to determine a classification are referred to as unclassifiable.

The federal attainment status designations of areas in New York with respect to NAAQS are listed at 40 CFR 81.333. The Project is located in Orange County in the Hudson Valley Intrastate Air Quality Control Region (AQCR), also known as AQCR 161.

The only criteria pollutants for which the Project is located in a nonattainment area are ozone and $PM_{2.5}$. Orange County is designated as a Subpart 2 / Moderate Nonattainment area with respect to the 8-hour ozone NAAQS. The Project is in a portion of Orange County (the Poughkeepsie Area) that was formerly designated as moderate nonattainment with respect to the 1-hour ozone NAAQS. However, the 1-hour ozone standard was revoked effective June 15, 2005 in all areas of New York. Orange County is also designated as nonattainment with respect to $PM_{2.5}$.

It should be noted that New York State's current nonttainment area regulations in the New York Codes, Rules and Regulations (NYCRR) at Part 231-2 still reference the 1-hour ozone NAAQS and have not yet incorporated the 8-hour NAAQS. The Project site is located in the "Lower Hudson Valley area" as defined in Part 200.1(av)(3)(ii)(a), an area designated as moderate nonattainment for ozone. Therefore, under both federal and state rules, the Project is in a nonattainment area for ozone.

2.3 Facility Operations and Sources

The proposed facility will be a combined cycle electric generating facility. In a combined cycle power plant, the hot exhaust gas from a gas turbine generator is used to generate steam in an HRSG. The hot steam is then expanded in a steam turbine to drive a generator to generate additional electricity.

The facility will have a 2x1 configuration, with two CTGs, two HRSGs, and one STG. The current facility design is based on the use of two Siemens Westinghouse SGT6-5000F CTGs. The CTG is an internal combustion engine that operates with a rotary motion to rotate a shaft to generate electricity. The CTG consists of three main sections: the compressor, the combustor, and the power turbine. Ambient air is drawn into the compressor section where it is compressed and then sent to the combustor section in which fuel is introduced, ignited, and burned. Hot gases from the combustion section are diluted with additional air from the compressor section and then directed to the power turbine section at high temperature where they expand. Energy is recovered in the form of shaft horsepower and used to drive the internal compressor and to drive the turbine and generate electricity.

High-temperature exhaust gases leave the CTGs and are directed to the HRSGs via ductwork. In the HRSGs, the heat from the exhaust gases is transferred to water/steam tubes and used to boil water into steam and to superheat the steam for use in the steam turbine generator to generate additional electricity. The exhaust gas from the HRSGs is routed to exhaust stacks. Each HRSG will have supplemental fuel firing provided by a natural gas-fired duct burner with a heat input capacity of approximately 500 million British thermal units per hour (MMBtu/hr) on a higher heater value (HHV) basis at an ambient temperature of 90 ^oF. Duct firing would occur only with natural gas and only when natural gas was also being combusted in the CTs. Figure 2-4 provides a conceptual flow diagram for a 2x1 combined cycle facility.

The CTs will mostly fire natural gas, although some backup use of ULSD is proposed. The CTs incorporate advanced dry low-NO_x combustion techniques when firing natural gas and water injection when firing ultra low sulfur distillate oil. Additional emissions controls on the combined cycle units consist of SCR systems to reduce emissions of NO_x and oxidation catalyst systems to reduce emissions of CO and VOC. The proposed emissions controls will be designed to reduce emissions from the CTs to the following concentration levels in parts per million (ppm) on a dry volume basis (ppmvd) at 15 percent oxygen (15% O_2):

- 2.0 ppmvd NO_x when firing natural gas;
- 6.0 ppmvd NO_x when firing ULSD
- 2.0 ppmvd CO when firing natural gas;
- 2.0 ppmvd CO when firing ULSD.

These emissions of NO_x and CO are based on ammonia slip levels of 2.0 ppmvd when firing natural gas and 5.0 ppmvd when firing ULSD. A sulfur content of 0.8 grains per 100 standard cubic feet (scf) of natural gas is assumed along with a SO_2 to SO_3 conversion rate of 20% in the emissions calculations for the combined cycle units.

Each CT will have a maximum heat input capacity of approximately 2,145 million British thermal units per hour (MMBtu/hr) when firing oil at an ambient temperature of -5 ^oF and a maximum heat input capacity of approximately 2,234 MMBtu/hr when firing natural gas at an ambient temperature of -5 ^oF. Each HRSG will have a maximum duct burner heat input capacity of approximately 500 MMBtu/hr when firing natural gas. The listed heat input capacities are on a HHV basis.

The ancillary sources of air emissions consist of some additional small combustion sources (an auxiliary boiler, an emergency diesel generator, a diesel fire water pump, and two fuel gas “dew point” heaters) and a 965,000 gallon oil storage tank. The auxiliary boiler will fire natural gas and will have a heat input capacity of approximately 73.5 MMBtu/hr. The emergency generator will fire only ULSD and will have an output rating of approximately 1,500 kilowatts (kW). The fire water pump will fire only ULSD and will have an output rating of approximately 325 brake horsepower (bhp). The diesel fire water pump will serve as a backup unit for an electric fire water pump. The fuel gas heaters will fire only natural gas and will have a heat input capacity of approximately 5 MMBtu/hr per heater.

Most of the ancillary combustion sources are expected to operate for limited periods of time. For example, the auxiliary boiler is expected to operate for no more than a few hours a day to assist with start-ups of the combined cycle units. The emergency generator and fire water pump will typically operate for up to two hours per week for readiness testing or maintenance purposes. In the event of a facility upset or emergency, these standby units could operate for longer periods during which the combined cycle units would not be operating. However, for the purposes of assessing worst-case short-term impacts, it will initially be assumed that these units could operate during any hour concurrent with the combined cycle units. The fuel gas heaters would be used to heat the incoming gas before it is fired in the combustion turbines and duct burners. It would be permitted to fire for the entire year.

2.4 Facility Potential to Emit

Annual potential to emit for the Project has been calculated based on the following assumptions regarding operation of equipment:

- Up to 8,760 hours of operation for each CTG firing natural gas;
- Up to 720 hours of operation for each CTG firing ultra low sulfur distillate oil;
- Up to the equivalent of 2,628 hours of supplementary duct firing for each HRSG/duct burner on natural gas (up to the equivalent of 5,256 total hours of supplementary duct firing for both HRSGs/duct burners per year), equivalent to a 30% plant capacity factor for duct firing;
- Up to 275 start-ups per year per turbine, including up to 40 cold starts per year;
- Up to 2,000 hours of operation per year for the auxiliary boiler;
- Up to 500 hours of operation per year for the emergency engine;
- Up to 500 hours of operation per year for the fire water pump; and
- Up to 8,760 hours of operation per year for each of the fuel gas heaters.

Emissions of PM from the combined cycle units include the filterable emissions associated with combustion in the CTs and duct burners as well as the condensable particulate emissions that would be measured by EPA Reference Method 202. The potential to emit for PM also includes emissions of ammonium sulfate salts that can form from the reaction of SO_3 with ammonia in the flue gas downstream of the SCR.

The resulting estimate of potential to emit for the Project is summarized in Table 2-1. The facility potential to emit for PM_{10}/$PM_{2.5}$ incorporates the effect of the proposed annual emissions cap. The facility potential to emit for VOC includes some negligible potential emissions from the oil storage tank due to working and breathing losses.

Table 2-2 compares the potential to emit from the Project to various regulatory thresholds. Potential to emit from the Project will exceed 100 tons per year (tpy) for NO_x and CO. Therefore, the Project will be a major stationary source subject to PSD permitting requirements. PSD review requirements, such as Best Available Control Technology (BACT) and/or ambient impact analyses, will apply to all pollutants with a potential to emit that exceeds the PSD significant emission rates (i.e, for NO_x, CO, SO_2, PM_{10}, and H_2SO_4).

The potential to emit for NO_x and VOC also exceeds the applicable nonattainment new source review (NNSR) major source thresholds of 100 tpy and 50 tpy, respectively, which apply in the project area. Therefore, major NNSR permitting requirements, such as lowest achievable emission rate (LAER) and emissions offsets, will apply to NO_x and VOC. The proposed annual emissions cap for PM will keep the Project potential to emit below the NNSR major source threshold of 100 tpy for $PM_{2.5}$. Therefore, major NNSR requirements will not apply to $PM_{2.5}$.

Potential to emit for hazardous air pollutants (HAP) will be below 25 tpy for total HAP and less than 10 tpy for each individual HAP. Therefore, the Project will not be a major source for HAP.

2.5 Selection of Sources for Modeling

The emission sources responsible for most of the potential emissions from the Project are the combined cycle units. These units will be included in and are the main focus of the modeling analyses. As discussed in Section 2.6, the modeling will include consideration of operation over a range of turbine loads and ambient temperatures for each fuel. The effects of supplementary duct firing and evaporative cooling will also be considered. Initial modeling of the combined cycle units by themselves for each fuel will be conducted to identify those operating conditions for each pollutant and averaging period that yield the maximum predicted impacts. Any subsequent modeling incorporating other emissions units at the plant or other facilities will include the combined cycle unit operating conditions that yield the maximum predicted impacts along with the operating cases that have the maximum emission rates. Modeling conducted for PM_{10} and $PM_{2.5}$ will include filterable and condensable PM.

Additional modeling to predict the short-term impacts of CO, PM, and SO_2 emissions from the combined cycle units during unit start-up will also be conducted to assess the potential effect of these emissions relative to established significant impact levels, short-term ambient standards, and short-term PSD increments.

Several ancillary sources (the emergency generator, the diesel firewater pump, the auxiliary boiler, and the fuel gas heaters) will also be included in the modeling. The emergency generator and diesel firewater pump may operate for up to two hours in any day for readiness testing and maintenance purposes. The emergency generator could also operate to assist with facility shutdown if external power to the facility is lost. Operation of the emergency generator for longer periods of time in an emergency mode would not be expected to occur when the combined cycle units are operating. It is expected that the auxiliary boiler will only be used for a few hours in any day to assist with startups of the combined cycle units. The fuel gas heaters could operate at any time that the combined cycle units are firing natural gas.

Although only limited operation is expected from many of the ancillary sources, initial modeling to assess short-term Project impacts will conservatively assume concurrent and continuous operation of the emergency generator, the firewater pump, the auxiliary boiler, and the fuel gas heaters along with the combined cycle units. However, the fuel gas heaters may only be included for those cases when the combined cycle units are firing natural gas.

2.6 Stack and Emission Parameters

2.6.1 Combined Cycle Units

Emissions and stack flow parameters for combustion turbines vary with turbine load and with ambient temperature. Emissions and associated stack parameters have been calculated for combinations of three turbine loads and three ambient temperatures for each of two proposed fuels (natural gas and ULSD).

The three modeled loads for each fuel were selected to span the range of normal operating loads. For natural gas, the modeled loads were base load (at or near 100%), 80%, and 60%. For ULSD, the modeled loads were base load, 85%, and 70%. The minimum selected loads are different for each fuel (i.e., 60% for natural gas and 70% for ULSD) to reflect the expected minimum normal operating load for the combustion turbines for each fuel. Lower operating loads are associated with transitional start-up operations.

The ambient temperatures for which stack and emissions parameters were defined are the annual average temperature for the Project area (51 ^oF) and representative high (90 ^oF) and low (-5 ^oF) ambient temperatures for the area and were selected based on discussions with NYSDEC staff. Operating conditions for operating cases with supplementary duct firing (for natural gas only) and for evaporative cooling were also defined.

Table 2-3 summarizes the emission rates of criteria pollutants that will be modeled and the associated stack flow parameters for the combined cycle units for fifteen (15) natural gas-firing operating cases and for ten (10) oil firing operating cases. These cases are designed to cover the envelope of normal operating conditions for the combined cycle units. All of the defined operating cases will be modeled for each hour of the 5-year meteorological period of record. This approach is conservative, since it includes combinations of emissions and meteorological conditions that are unlikely to occur at the same time (such as 90 °F emissions cases being modeled in January and the -5 °F emissions cases being modeled in July).

The emission rates in Table 2-3 will be used to predict maximum short-term impacts for the combined cycle units. Maximum annual impacts for gas firing for the entire year will also use the same emission rates. Maximum annual impacts reflecting the maximum amount of proposed oil firing (720 hours per year per unit) with gas firing for the rest of the year will be determined by summing annual impacts predicted separately from oil firing and from gas firing using emission rates scaled to account for 720 hours and 8,040 hours per year of operation on oil and gas, respectively, per unit and using stack parameters for the worst-case normal annual operating condition for the associated fuel. The identification of the worst-case operating conditions for the combined cycle units is discussed in Section 4.1.

Startup cases for the combined cycle units will be modeled separately using stack flow parameters associated with startup and calculated emission rates characteristic of startup. Information concerning startup and shutdown emissions is summarized in Table 2-4. Emissions associated with shutdown are lower than those for startup and have a shorter duration. Therefore, impacts during startup would be expected to exceed those during shutdown, and shutdown emissions will not be modeled. Additional information concerning startup operations, emissions, and modeling for startup is provided in Section 4.4.

Each combined cycle unit will exhaust to a dedicated stack. The proposed stack heights for the two combined cycle units will be 275 feet above a base elevation of approximately 464 feet (141.43 meters (m)) above MSL and will have an inner exit diameter of 19 feet (5.791 m).

2.6.2 Emergency Generator

Stack parameters and emission rates of criteria pollutants from the emergency generator are summarized in Table 2-5. The proposed stack height for the emergency generator is 50 feet (15.24 m) above local grade.

2.6.3 Auxiliary Boiler

Stack parameters and emission rates of criteria pollutants from the auxiliary boiler are summarized in Table 2-6. It is expected that the auxiliary boiler will exhaust to the atmosphere through the southern combined cycle stack. However, no credit in the modeling will be taken from any potential merging of exhaust from a combined cycle unit and the auxiliary boiler. The auxiliary boiler will be modeled with stack parameters that reflect only the volumetric flow rate from the boiler.

2.6.4 Firewater Pump

Stack parameters and emission rates of criteria pollutants from the firewater pump are summarized in Table 2-7. The proposed stack height for the firewater pump is 50 feet (15.24 m) above local grade.

2.6.5 Fuel Gas Heaters

Stack parameters and emission rates of criteria pollutants from the fuel gas heaters are summarized in Table 2-8. The current proposed stack height for the heaters is 125 feet (38.1 m). Emissions from the fuel gas heaters will be modeled assuming a single stack location with an emission rate associated with two heaters but with a volumetric flow rate associated with a single heater. Therefore, no credit is being taken in the modeling for any merging of fuel gas heater flows or plumes.

2.7 Stack Locations

Stack locations based on the current Project design are summarized in Table 2-9. Locations are provided in Universal Transverse Mercator (UTM) coordinates for Zone 18 referenced to the North American Datum of 1983 (NAD 83).

2.8 Good Engineering Practice Stack Height Analysis

Section 123 of the Clean Air Act Amendments of 1977 required EPA to promulgate regulations to assure that the control of any air pollutant under an applicable State Implementation Plan (SIP) was not affected by stack heights that exceed Good Engineering Practice (GEP) or by any other prohibited dispersion technique. The EPA provides specific guidance for determining GEP stack height in the "Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack height Regulations)" (EPA-454/4-80-023R, June, 1985). GEP, with respect to stack height, is defined in Section 123 of the Clean Air Act

Amendments of 1977 as "the height necessary to insure 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 which may be created by the source itself, nearby structures, or nearby terrain obstacles." GEP is further defined in 40 CFR 51.100(ii) for new stacks as the greater of 65 meters (the *de minimis* GEP height) or the height calculated as described below.

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 significant adverse aerodynamics (downwash) are avoided. The stack height regulations specify that the GEP formula stack height be calculated in the following manner:

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

where:
- HB = the height of adjacent or nearby structure, and
- L = the lesser dimension (height or projected width) of the structures.

The largest structures proposed for the Project site are listed in Table 2-10.

The largest structures at the Project site will be the air cooled condensers. This structure is squat (projected width exceeds height), and each stack is within range of this structure (within 5L). The most recent version of the Building Profile Input Program for PRIME (BPIPPRM), dated 04274, was used to determine GEP stack height and the effective building dimensions as a function of flow vector for each of the stacks that will be modeled. The resulting GEP formula height for the combined cycle unit stacks is 287.5 feet. GEP formula height for the FWP stack is slightly lower (283.5 ft) due to its slightly higher stack base elevation relative to the air cooled condensers. Figure 2-5 provides a schematic plot showing the proposed locations of the buildings and stacks superimposed on the site plan. Figure 2-6 provides a more detailed general arrangement site plan.

The proposed combined cycle stacks will be slightly below GEP formula stack height. Therefore, the modeling will account for the potential effects of building downwash on emissions from the combine cycle stacks. Stacks for other Project sources (auxiliary boiler, ESD, FWP, and fuel gas heaters) will also be lower than GEP formula stack height. Therefore, the modeling will account for the potential effects of building downwash on emissions from these other stacks as well.

Representative BPIPPRM input and output files, including the sector specific building parameters to be used in the modeling for the proposed stack locations, are presented in Appendix A.

3.0 MODELING METHODOLOGY

This section describes the procedures that are proposed for conducting the air quality modeling analyses to support the air permit application and EIS. The following subsections describe the model to be used, model input options, meteorological data, land use, and model receptors.

3.1 Model Selection and Options

The AERMOD model (version 07026) will be used to determine predicted impacts from the proposed Project. AERMOD is identified by EPA in the "Guideline on Air Quality Models" (40 CFR 51, Appendix W) as a recommended refined model for a wide range of regulatory applications in all types of terrain and in cases where aerodynamic downwash is important. AERMOD includes the PRIME downwash algorithm which accounts for potential building wake and cavity effects on stack emissions. AERMOD also includes a refined complex terrain algorithm and can provide predicted impacts in all terrain regimes.

The proposed stack heights are below the maximum GEP formula height calculated based on proposed buildings and structures, so building downwash may affect stack emissions. In addition, some stack heights are short enough relative to nearby structures that building cavity effects on stack emissions may be important. As mentioned above, AERMOD can account for building wake and cavity effects on stack emissions. The receptor grid, described later, includes some receptors in simple terrain and others that are in complex terrain (i.e., terrain that exceeds the height of the stacks). In complex terrain, AERMOD employs the dividing streamline concept to treat the effects of plume and terrain interactions. As mentioned previously, AERMOD is recommended for use in all terrain regimes. For these reasons, AERMOD is an appropriate and recommended model to use for estimating impacts from Project emissions. Therefore, AERMOD with regulatory default model options is proposed for use for these modeling analyses.

3.2 Receptor Grid

The basic receptor grid for the AERMOD analyses will be defined by the intersections of concentric circles and radial lines paced at ten degree intervals from the center of the circles. The circles will be centered on a point in the power generation area of the Project. The grid will be "polar" in nature, but the receptor coordinates will be provided to AERMOD as discrete Cartesian receptors in UTM coordinates referenced to zone 18 (NAD 83). The basic grid origin will be centered on a point with the following coordinates: (545,909.0 meters E, 4,584,682.75 meters N). Receptors will be located every 10 degrees at the following distances from the origin:

- At 100m intervals from 200m to 5,000m;
- At 200m intervals from 5,000m to 10,000m;
- At 500m intervals from 10,000m to 15,000m; and
- At 1,000m intervals from 15,000m to 30,000m.

Fence line receptors will be included at intervals of 10 meters or less surrounding the facility. Grid receptors within fenced plant property will be excluded from the grid.

The final proposed receptor grid consists of 3,552 grid receptors and 180 fence line receptors for a total of 3,732 model receptors. Figure 3-1 displays the fence line along with the locations of proposed Project stacks and major buildings and structures. Figure 3-2 shows the grid receptors out to 5,000 meters, while Figure 3-3 shows the entire receptor grid out to 30,000 meters. The receptor grid points are plotted over a background that depicts the underlying terrain field.

The AERMAP (Version 06341) preprocessor program will be used to extract receptor elevations and hill heights based on 10m Digital Elevation Model (DEM) data. The analysis will use 7.5-minute DEM data obtained from the US Geological Survey (USGS). The DOMAINXY keyword will be used to define the geographic extent of domains for the inner and outer grids using UTM coordinates (NAD83). Since receptor locations will be in UTM coordinates, the ANCHORXY keyword line will use the same values for the user coordinates and UTM coordinates of the anchor point for each grid. Appendix B contains extracts from the AERMAP input files showing the control pathway lines.

3.3 Meteorological Data

According to the "Guideline on Air Quality Models" the meteorological data used in modeling analyses should be selected based on their spatial and climatological representativeness with respect to the proposed facility site and its ability to characterize transport and dispersion over the modeling domain. The representativeness of the meteorological data is assessed based on several factors, including the proximity of the meteorological monitoring site, the complexity and nature of the terrain, the exposure of the monitoring site, and the period of time during which data were collected. Both hourly surface data and twice-daily upper air observations are needed for modeling analyses with the AERMOD model.

3.3.1 Surface Level Meteorological Data

The nearest sources of hourly surface level meteorological data for modeling impacts from the Project are Orange County Airport (MGJ) in Montgomery, New York and Stewart International Airport (SWR) in Newburgh, New York. Five years of hourly surface level data for the period (2002-2006) were obtained for each site and reviewed to determine their representativeness for the Project location and their suitability for regulatory air dispersion modeling using the AERMOD model. Figure 2-3 shows the location of each airport relative to the Project site and the surrounding terrain.

Orange County Airport (MGJ)

MGJ is located approximately 18 km northeast of the Project site and has a similar setting relative to the broad surrounding terrain. The base elevation at MGJ (approximately 110 meters MSL) is comparable to that at the Project site. Hills rising to approximately 150 to 200 meters MSL occur along a southwest to northeast axis approximately 2 to 3 km to the northwest that conforms to the general orientation of the higher terrain that defines the broader valley walls. The well defined ridge with typical peak elevations on the order of 350 meters MSL that is located about 11.5 km to the west-northwest of the Project site is located about 17 km to the west-northwest of MGJ and has the same orientation before broadening and turning slightly to more of a southwest to northeast orientation as it heads north. The Hudson River is approximately 21 km to the east, and Long Island Sound is located approximately 80 km to the southeast.

A wind rose plot for MGJ based on five years of surface level meteorological data (Figure 3-4) shows prevailing winds from the south-southwest and north-northeast, consistent with the orientation of the broad valley. Winds from the west-northwest and southwest are also fairly frequent, likely reflecting larger scale synoptic flows that vary seasonally with frequent winds from the northwest in the winter and winds from the southwest in the summer. Based on the similar setting of the project site and Orange MGJ relative to nearby and larger scale terrain features and the conformance of the prevailing winds at MGJ to the broad valley orientation, it is concluded that the wind flow data measured at MGJ should be representative of conditions that would be expected at the Project site.

Five years of hourly surface observations (2002-2006) from MGJ were obtained from the United States National Climatic Data Center and reviewed for completeness and for out of range values. Table 3-1 summarizes the percentage of data capture and acceptance for wind speed, wind direction, ceiling height, temperature, relative humidity, and surface pressure. The data capture and acceptance rates in the meteorological data set from MGJ for these parameters were well over the 90 percent level required for projects subject to PSD.

The five year period of record (2002-2006) selected for MGJ satisfies EPA and NYSDEC requirements related to length of record (i.e., five consecutive years) and currency for the use of off-site meteorological data. As discussed previously, the meteorological data from MGJ should be representative of conditions at the Project site and satisfy data capture rates required for PSD projects. Therefore, the surface level meteorological data from MGJ are suitable for modeling the Project.

Stewart International Airport (SWF)

Stewart International Airport (SWF) is located approximately 30 km east-northeast of the Project site. Although it is located in the same broad valley and has a comparable base elevation (approximately 140 meters MSL), there are some significant differences in its setting relative to the Project site. The well-define ridge of terrain discussed previously is considerably more distant, approximately 29 km to the northwest of the Project site, and some of the terrain elevations associated with the nearest portion of the ridge are on the order of 600 meters MSL. Smaller hills with peaks on the order of 200 meters MSL occur 1 to 2 km north and south of SWF. The Hudson River is located approximately 8 km to the east, and the nearest portion of Long Island Sound is approximately 70 km to the southeast.

A wind rose plot for SWF based on five years (2002-2006) of surface level meteorological data (Figure 3-5) shows prevailing winds from the west. The wind rose does not show any effect of the broad valley orientation. Rather, the wind rose appears to reflect what may be some strong local flow channeling due to nearby terrain features as well as average larger scale flows from the west. The wind distribution at SWF is significantly different from the broad valley orientation and from the distribution observed at MGJ. The wind speeds at SWF are also higher than those at MGJ, indicating greater exposure and a flow less impeded by nearby hills at SWF. Given the distinctly different wind rose distribution from that expected at the Project site and given the greater distances of the airport from the Project site, the surface level meteorological data from SWF are not likely to be representative of conditions at the Project site.

Data capture rates for winds from SWF for the five-year period average about 80%, well below the 90% data capture rate required for PSD projects. For this reason alone, the data from SWF would not be suitable for modeling for the Project.

3.3.2 Upper Level Meteorological Data

A concurrent five year period (2002-2006) of upper air data collected from Albany International Airport (ALB) is proposed for use in the air quality impact assessment for the Project. Albany International Airport is located approximately 158 km north-northeast of the Project site and represents the nearest source of representative upper air data for the Project. Other potential sites with upper air data, such as Brookhaven National Laboratory (OKX) and Atlantic City (ACY), are either more distant from the Project site (as is the case for ACY) or located in coastal or near coastal environments (OKX and ACY). Use of upper air data from Brookhaven or Atlantic City would likely introduce marine influences and effects that would not be expected to occur at an inland location like the Project site.

The meteorological data will be processed with the AERMET meteorological preprocessor (Version 06341). The output from AERMET will be used as the meteorological database for the air quality modeling analyses and will consist of a surface data file and a vertical profile data file. The required boundary layer parameters needed for AERMET are discussed in the following section.

3.4 Land Use

The AERMOD modeling system uses AERMET to process meteorological data. Values of three surface characteristics (surface roughness length, Bowen ratio, and albedo) are required inputs for AERMET.

EPA's AERSURFACE tool (most recent version dated 08009) was used to determine the needed surface characteristic values. AERSURFACE was developed by EPA to provide realistic and objectively determined surface characteristic values for use in the AERMET meteorological preprocessor. Although the use of AERSURFACE is not required for regulatory applications involving AERMOD, EPA states that the calculation methods recommended by in the AERSURFACE User's Guide and implemented in AERSURFACE should be followed unless a case-specific justification is provided for an alternative method.

AERSURFACE requires the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92 data). AERSURFACE determines values of surface roughness length based on an inverse-distance weighted geometric mean for an upwind distance of 1 km relative to the surface level meteorological measurement site and allows for the use of sectors of 30 degrees or larger to account for variations in land cover in the vicinity of the measurement location. For the Bowen ratio and albedo, AERSURFACE calculates simple unweighted averages (geometric mean for Bowen ratio and arithmetic mean for albedo) over a 10 km by 10 km area centered on the measurement site.

Figure 3-6 presents a plot of land use (NLCD92 data) in the vicinity of the meteorological tower location at MGJ. The location of the meteorological tower (41.509° N latitude, 74.266° W longitude) was provided by NYSDEC based on verified geographic information system (GIS) data. Following a review of NLCD92 data within 1 km of the measurement location, four sectors were defined to reflect the distribution of land use. Since AERSURFACE calculates surface roughness length based on an inverse distance weighted geometric mean value for each sector, land uses closest to the meteorological measurement site are more important in determining a representative surface roughness length for a given sector. The land uses with the highest associated surface roughness lengths in the vicinity of the measurement site are those for forest and low intensity residential. The distribution of these land uses was the primary factor used in defining the four sectors.

AERSURFACE was then run using NLCD92 data. NYSDEC staff had suggested the use of data from the New York State Land Cover Data Set for 1997. However, these data are not compatible with AERSURFACE. Comparison of the pattern of land use as represented in the NLCD92 data versus that in the New York State data from 1997 (see Figure 3-7) shows little change or difference. Given the lack of any significant changes from 1992 to 1997 in the land use, there was no compelling reason to incorporate the use of the more recent data, especially given its lack of compatibility with AERSURFACE.

The AERMET User's Guide (Table 2-2) provides seasonal values for various land use categories and characterizes winter, spring, summer, and autumn in reference to vegetative growth cycles. Months were assigned to AERMET seasonal categories in accordance with guidance from NYSDEC as follows:

- June, July, August, and September were assigned to Seasonal Category 1 (Midsummer with lush vegetation);
- October and November were assigned to Seasonal Category 2 (Autumn with unharvested cropland);
- December, January, February, and March were assigned to Seasonal Category 3 (Late autumn after frost and harvest, or winter with no snow); and
- April and May were assigned to Seasonal Category 5 (Transitional spring with partial green coverage or short annuals).

AERSURFACE input and output files are provided in Appendix C.

Current EPA guidance calls for the use of surface parameters based on the area surrounding the meteorological measurement site. Section 3.3.1 previously discussed and justified the selection of surface level meteorological data from MGJ as representative of the Project site. In response to agency requests, Figure 3-8 is provided to show the land uses surrounding the Project site.

In order to compare the land use surrounding MGJ and the Project site and the associated surface parameters, AERSURFACE was run for each site. A single 360 degree wide sector was used in each case for the purpose of obtaining average values of surface roughness length for the area surrounding each site. Table 3-2 provides the resulting monthly values for each of the surface parameters, the ratio of the monthly values at each site, and annual averages of the surface parameter values and ratios.

Review of the values in Table 3-2 shows that: (1) the monthly albedo values are identical at each site; (2) the Bowen ratio is slightly higher at the airport but always within 10 percent of the value at the airport; and (3) surface roughness lengths are more variable, as would be expected, since surface roughness is determined based on a more limited area. However, the average surface roughness values are always fairly small (less than 0.3 meters), and the average values and calculated ratios are not significantly different. The annual average values of surface roughness at each site are within 7 percent. The ratios of the natural logarithms of the monthly average values of surface roughness are always within 20 percent, and the annual arithmetic average of these monthly ratios differs only by about 1 percent. Natural logarithms were used to compare the respective surface roughness lengths at the two sites consistent with the manner in which this parameter is used by AERMOD.

Based on these comparisons, it is concluded that differences in land usage surrounding the airport and Project site will not have any significant effect on the associated surface parameters used in AERMOD and that the land usage surrounding MGJ is suitably representative of land usage at the Project site.

4.0 MODELING ANALYSES

Air quality modeling analyses will be conducted for a variety of purposes, including: to determine worst-case operating conditions for the combined cycle units, to compare Project impacts to significant impact levels (SILs) and significant monitoring concentrations (SMCs), to demonstrate that the Project will not cause or contribute to violations of NAAQS or Class II PSD increments, and to demonstrate that emissions of non-criteria pollutants from the Project will not exceed acceptable air concentrations defined by NYSDEC for non-criteria pollutants. Visibility screening modeling will be conducted to demonstrate that predicted impacts on visibility in the nearest Class I area will be below default screening threshold levels. A visibility screening modeling analysis will be conducted to assess potential effects at significant peaks in the Catskills State Park. Additional analyses to assess other potential Project impacts will also be conducted, including impacts from a hypothetical failure of the Project ammonia storage tank, potential visible water vapor plumes from the combined cycle stacks, and potential acidic deposition at identified sensitive receptors in New York. The following subsections discuss the modeling analyses that are proposed.

4.1 Identification of Worst-Case Operating Conditions for Combined Cycle Units

Modeling for the combined cycle units has been conducted for the matrix of representative normal operating conditions described previously to identify the worst-case operating condition (i.e., the operating condition that yields the maximum predicted ground-level impacts). The worst-case operating condition for the combined cycle units has been identified for each fuel and modeled criteria pollutant and associated averaging period for which a NAAQS or PSD increment has been defined. The resulting worst-case operating conditions will be included for the associated pollutant and averaging period along with the maximum emissions case in any subsequent modeling to determine impacts from the Project itself or cumulative impacts from the Project and other facilities.

Table 4-1 provides a summary of the results of modeling conducted for the combined cycle units using procedures described in this protocol. The normal combined cycle unit operating condition identified as worst case for each combination of fuel, load, and ambient temperature is indicated in the table by shading. Table 4-2 lists the operating case ID, as cross referenced to Table 2-3, identified as the worst-case normal combined cycle unit operating condition for each fuel, pollutant, and averaging period. Table 2-3 also lists the maximum emissions cases for each fuel and pollutant combination.

4.2 Modeling to Compare Project Impacts to SILs and SMCs

Modeling will be conducted to allow for a comparison of maximum predicted Project impacts with Class II SILs that have been established by EPA at 40 CFR 51.165(b)(2) and with SMCs defined at 40 CFR 52.21(i)(5)(i). A demonstration that maximum impacts will be less than the corresponding SIL for a given pollutant and averaging period will establish that the proposed Project will not, by definition, be capable of causing or contributing to any violation of a corresponding NAAQS or PSD increment.

Under longstanding EPA guidance and interpretations, the SILs are used to determine if a source makes or could make a significant contribution to a predicted violation of a NAAQS or Class II PSD increment. If a major source or major modification is predicted to have maximum impacts that are below the SILs, then a cumulative (or "full") impact analysis that includes other facilities is not required, and the impacts of the project are considered to be *de minimis* or insignificant. By showing that maximum predicted Project impacts will be below the corresponding SILs for a given pollutant, the Project will be exempt from the requirement to conduct any additional analyses to demonstrate compliance with NAAQS and/or Class II PSD increments for that pollutant.

It is expected that the modeling conducted to compare Project impacts to SILs will also serve to demonstrate that impacts from the Project will be below SMCs defined at 40 CFR 52.21(i)(5)(i). If a major new source or major modification can demonstrate that its impact is less than the SMC, then the source is exempt from preconstruction monitoring requirements that might otherwise apply under the PSD program. Table 4-3 also includes the established SMCs. The Project will submit requests to EPA and NYSDEC for a waiver from preconstruction monitoring requirements when the modeling of Project impacts has been completed.

Modeling to determine Project impacts relative to SILs and SMCs will include the combined cycle units for those operating conditions that are predicted to yield the maximum predicted impacts from those units and for those conditions that have the highest emission rates as described in Section 4.2. Potential impacts associated with turbine startups, as discussed in Section 4.5, will also be considered in assessing Project impacts relative to SILs and SMCs. The ancillary sources will also be included in this assessment. Modeling for comparison of Project impacts to short-term SILs and SMCs will use emission rates associated with short-term emissions. Modeling for comparison with annual SILs and SMCs will account for any limits on annual hours of operation for the ancillary units and for the maximum proposed level of ULSD firing in the combined cycle units. Prediction of annual NO_2 impacts will incorporate use of the Ambient Ratio Method in which initial estimates of maximum NO2 impacts based on an assumed total conversion of NO_x to NO_2 are then multiplied by the national annual default NO_2/NO_x ratio of 0.75 recommended by EPA.

Table 4-3 lists the NAAQS, Class II PSD increments, and SILs that have been established by EPA and as well as some New York Ambient Air Quality Standards that have been established by NYSDEC.

4.3 Modeling for $PM_{2.5}$

No SILs have been formally established by EPA or NYSDEC for $PM_{2.5}$. EPA has proposed a range of possible SILs for $PM_{2.5}$ but has not taken final action on its proposed rulemaking.

NYSDEC Commission's Policy 33 (CP-33), "Assessing and Mitigating Impacts of Fine Particulate Matter Emissions" was issued on December 29, 2003 for use with projects for which NYSDEC is the lead agency conducting a review for purposes of the State Environmental Quality Review Act (SEQRA). CP-33 requires an assessment of ambient impacts from projects with potential PM_{10} emissions exceeding a *de minimis* threshold of 15 tpy. For projects with emissions exceeding this emissions threshold, CP-33 uses 24-hour and annual Project impact levels of 5 micrograms per cubic meter ($\mu g/m^3$) and 0.3 for $\mu g/m^3$, respectively, to determine if a Project has a “potentially significant adverse impact.” A Project that exceeds either of these impact levels is then required to prepare an Environmental Impact Statement (EIS). NYSDEC is not the lead agency for SEQRA review for the project, so CP-33 may not strictly apply to this Project. Nonetheless, a full EIS is being prepared for the Project and will include consideration of potential $PM_{2.5}$ impacts.

Northeast States for Coordinated Air Use Management (NESCAUM) has recommended that states adopt interim SILs for $PM_{2.5}$ for assessing project impacts until SILs are issued by EPA. NESCAUM originally recommended that levels of 2.0 $\mu g/m^3$ for the 24-hour averaging period and 0.3 $\mu g/m^3$ for the annual averaging period be used as surrogate SILs for $PM_{2.5}$ until values are formally established by EPA. Both NYSDEC and EPA have stated that use of the surrogate SILs recommended by NESCAUM is not unreasonable at this time. EPA has noted that NESCAUM subsequently indicated its support for a lower value (1.2 $\mu g/m^3$) corresponding to the lowest of three values proposed by EPA. However, these surrogate SILs proposed by NESCAUM have no regulatory standing at this time.

The Project is in a $PM_{2.5}$ nonattainment area. As discussed previously, the Project will propose an enforceable annual PM emissions cap of 95 tpy along with associated recordkeeping and reporting measures to ensure that actual PM emissions will not exceed 95 tpy on a rolling 12-month basis. Therefore, the Project will not be subject to major NNSR requirements, such as emission offsets and LAER, for $PM_{2.5}$. In addition, other requirements that would apply to a new major $PM_{2.5}$ source in a $PM_{2.5}$ nonattainment area, such as the requirement to demonstrate a net air quality benefit, will therefore not apply to the Project. Instead, the Project will be subject to minor NNSR permitting requirements for $PM_{2.5}$. The modeling requirements associated with minor NNSR permitting for $PM_{2.5}$ have not yet been clearly established by either EPA or NYSDEC.

The Project proposes to conduct modeling to determine its predicted 24-hour and annual $PM_{2.5}$ impacts. Impacts for 24-hour periods will include overall maximum values as well as values corresponding to the 98th percentile in order to be consistent with the form of the associated NAAQS for $PM_{2.5}$. The maximum annual and 98th percentile 24-hour predicted Project impacts will also be considered in conjunction with representative background values and compared to the NAAQS for $PM_{2.5}$.

4.4 Modeling for Non-Criteria Pollutants

Modeling of non-criteria pollutants from the proposed Project will also be conducted. The modeling will consider the full range of normal operating conditions for the combined cycle units as well as emissions from the ancillary combustion sources. Maximum predicted impacts will be compared to Annual Guideline Concentrations (AGCs) and 1-hour Short-Term Guideline Concentrations (SGCs) defined by NYSDEC in order to demonstrate that these ambient limits for non-criteria pollutants will be met.

Each combined cycle operating case and each ancillary source will be modeled with a unit emission rate, and impacts for each case and ancillary source will be determined by scaling the resulting impacts by the pollutant-specific emission rate. Annual impacts for particular sources will be adjusted to account for proposed annual limits on operation. The combined cycle case yielding the maximum predicted impact for each criteria pollutant will be identified and then added to the maximum predicted impacts for each of the ancillary sources for comparison with associated AGCs and SGCs. The initial estimates of total impacts will be based on the sum of individual predicted maximum impacts for Project sources. These maximum predicted impacts from different sources may not occur at the same time or at the same location. If the total predicted impact for any non-criteria pollutant exceeds an associated guideline concentration, the pollutant-specific modeling to obtain total concentrations on a temporally and spatially consistent basis will be conducted to demonstrate compliance with the associated AGC and SGC as necessary.

4.5 Modeling for Startup Operation

Startup is a short-term, transitional mode of operation for the combined cycle units. Emission rates of some pollutants may be higher during startup operations because emissions controls may not become fully effective until a minimum threshold operating load is attained.

The need for additional modeling to account for predicted short-term Project impacts during startup of the combined cycle units will be assessed for those criteria pollutants whose short-term emission rates during startup may exceed those during normal operation and for which a short-term NAAQS or PSD increment has been defined (i.e., for CO and PM). In addition, the need for startup modeling will be assessed for SO_2. The short-term duration of startup and the relatively limited cumulative time of startup relative to normal operation mean that startup impacts will not have an appreciable effect on annual impacts. For these reasons, no modeling for the annual impacts of startup operation is proposed.

Startup emissions and associated stack parameters have been estimated for each fuel and for three varieties of startup (cold, warm, and hot) based on available data and engineering judgment. Startup emissions and emission rates based on the average of two combined cycle units during startup were calculated. The duration of startup varies between about 1.4 hours and about 2.3 hours depending on the type of startup and the fuel. The modeling to estimate impacts during startup will assume that startup will last for 2 hours. Modeling for startup will use the full short-term (g/s) emission rate for CO, PM, and SO_2 calculated as the total emissions per start divided by the duration of the start as listed in Table 2-4. For cold startups, which may last for more than 2 hours, the g/s emission rate for startup will be scaled up by the ratio of the event duration to 2 hours to ensure that total cold startup emissions during individual starts are not underestimated.

Table 4-1 contains results of startup modeling for the combined cycle units. Maximum 1-hour predicted impacts during startup are listed along with maximum 1-hour predicted impacts during non-startup operating conditions.

A comparison of the maximum 1-hour start-up and non-startup impacts for SO_2 indicates that impacts from startup emissions are smaller than impacts for non-startup operating cases that will already be fully considered in modeling to determine maximum impacts from the Project. For example, the maximum predicted 1-hour SO_2 startup impacts for gas firing are less than the maximum predicted 1-hour SO_2 impacts for cases SG02, SG06, and SG10 (for gas firing) that will already be considered in the modeling. Although the maximum predicted 1-hour cold startup SO_2 impacts for ULSD firing exceed the maximum 1-hour SO_2 impacts predicted for cases SF01, SF09, and SF10 (for ULSD firing), these cold startup SO_2 impacts are less than those for the 1-hour gas firing cases that will be modeled for SO_2. Therefore, maximum short-term SO2 impacts are those associated with normal operation when firing gas in the combustion turbines, and there is no need to consider SO_2 startup emissions in further modeling to determine maximum Project impacts.

Similarly, the maximum predicted 1-hour PM startup impacts during gas firing are less than the maximum predicted 1-hour PM impacts for cases SG02 and SG06 that will be modeled to determine maximum short-term PM impacts. Therefore, there is no need to consider PM startup emissions during gas firing in further modeling to determine maximum impacts from the Project.

The maximum predicted 1-hour PM startup impacts during ULSD firing are somewhat greater than the maximum predicted 1-hour PM impacts for cases SF03 and SF06 that will be modeled to determine maximum short-term PM impacts from the Project. The maximum startup 1-hour impacts of PM are predicted to occur for cold startups, so consideration of PM impacts during startup of the turbines will be limited to the worst case of cold starts.

The following procedure was followed to develop a proposed method to account for the potential effect of cold starts on PM impacts. The combined cycle units were modeled for all five years assuming continuous operation in cold start mode when firing ULSD, and maximum predicted 2-hour impacts in each year were determined. It was observed that the maximum cold start (2-hour) PM impacts in each year were associated with cold temperatures, light winds, and winds from the southwest blowing towards higher terrain to the northwest. The worst-case cold start PM impacts were predicted to occur during hours 1 and 2 in 2002, during hours 21 and 22 in 2003, during hours 23 and 24 in 2004, during hours 5 and 6 in 2005, and during hours 21 and 22 in 2006. The predicted maximum 2-hour PM impacts during cold starts were highest in 2005. In each year, additional model runs for PM will be made assuming that the combined cycle units operate in cold start mode for two hours every day (during the hours that yielded the maximum predicted 2-hour cold start impacts for that year) with the combined cycle units operating in the worst-case normal impact case during ULSD firing (i.e., SF06) for the remaining 22 hours of each day. This approach can be considered conservative because: (1) it includes the worst-case cold startup episode for each year; (2) it uses a short-term cold start emission rate that has been scaled upward to account for the total startup emissions per start as if it occurred within a 2-hour period; and (3) because it assumes continuous operation of the combined cycle units throughout the day using the normal operating condition associated with maximum predicted 24-hour PM impacts, while a cold start would normally be preceded by 48 hours or more of turbine downtime.

A comparison of the maximum 1-hour start-up and non-startup impacts for CO shows that the maximum 1-hour startup impacts of CO are much greater than the maximum predicted non-startup emissions. Therefore, the effect of CO startup impacts will be considered in subsequent modeling to determine maximum potential Project CO impacts.

The maximum 1-hour turbine impacts are those associated with cold ULSD startups. Therefore, consideration of startup impacts for CO for the 1-hour averaging period will use the worst-case operating conditions associated with cold startups on ULSD. For the 8-hour averaging period, a worst-case operating scenario that includes a cold start on ULSD along with normal operation on ULSD for the remainder of the 8-hour period will be assumed to occur each day. The daily cold starts in a particular year will be assumed to occur during the same two hours that correspond to the day with the associated maximum 2-hour cold startup impacts during that year, with normal operation on ULSD assumed for the remainder of the day for the normal ULSD operating case associated with maximum 8-hour CO impacts (i.e., SF06).

In modeling that combines startup impacts from the combined cycle units on ULSD with other sources, emissions from the natural gas heaters may be excluded, since the heaters would not be operating or needed during periods of oil firing in the combined cycle units.

4.6 Background Air Quality Levels

Conservative estimates of background ambient air quality have been determined by reviewing available sources of ambient monitoring data. Data for the three most recent years (2005-2007 for most pollutants) were obtained from EPA's AIRDATA database.

Table 4-4 summarizes the monitoring locations that were selected to represent background air quality concentrations and ambient levels that were measured at these stations in recent years. Most of the selected monitoring sites are located in areas that are more urban than the Project site and at which higher air pollution levels would be expected compared to the Project site.

The proposed annual background levels of most pollutants are based on the highest annual concentration measured at the selected sites over the three most recent years. The proposed short-term annual background levels of most pollutants are based on the highest second-high concentration measured at the selected sites over the three most recent years.

An annual PM-2.5 background value equal to 10.8 $\mu g/m^3$ is proposed based on the average annual concentration at this monitor over the last three years. A 24-hour $PM_{2.5}$ background value of 29.3 $\mu g/m^3$ is proposed based on the average of the 98^{th} percentile values at this monitor over the last three years, consistent with the form of the 24-hour $PM_{2.5}$ standard.

4.7 Cumulative Impact Modeling

Cumulative impact modeling involving other facilities will only be conducted for pollutants that satisfy all of the following criteria:

- the Project is in an attainment or unclassified area for the pollutant; and

- the Project has predicted impacts exceeding SILs.

If Project impacts are below SILs for a given pollutant, then no cumulative impact modeling analysis is required for the air permit applications. If Project impacts exceed SILs for a given pollutant, then other facilities will be modeled over a receptor grid that covers the predicted significant impact area for the Project. The other facilities to be modeled will be selected in accordance with guidance in Appendix C and information in Appendix D of NYSDEC's DAR-10. In any cumulative impact modeling, the Project will be included for the worst-case operating scenarios previously defined, including a startup scenario if appropriate.

Preliminary modeling conducted consistent with procedures in this modeling protocol indicates that cumulative impact modeling will only be needed for PM_{10} for oil firing and that the significant impact area for PM_{10} (24-hour) extends less than 5 km..

The Project has requested PM_{10} emission inventory information from NYSDEC, from the Pennsylvania Department of Environmental Protection, and from the New Jersey Department of Environmental Protection. The Project is currently reviewing and analyzing the available information that has been received in response.

4.8 Additional Impact Analyses

PSD regulations require additional analyses to determine potential facility impacts to soils and vegetation, impacts to visibility, impacts to Class I areas, and impacts to industrial, commercial, and residential growth. Proposed analysis techniques for additional impacts are provided in the following sections.

4.8.1 Impacts to Soils and Vegetation

An evaluation of potential impacts on sensitive vegetation in the vicinity of the Project will be conducted in accordance with "A Screening Procedure of the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA, 1980). Predicted impacts of the Project for SO_2, NO_2, and CO will be determined and added to ambient background levels. The resulting total concentrations will be compared to screening concentrations that represent the minimum levels at which adverse effects to plants have been reported.

As an extension to the analysis of impacts to soils and vegetation, the CPV Valley Energy Center has consulted with the U.S. Fish and Wildlife Service (FWS) to determine if there are any endangered or threatened species in the vicinity of the Project. CPV Valley Energy Center is continuing to work with FWS to ensure that the Project .will have no adverse effect on endangered or threatened species or associated habitat.

4.8.2 Class I Impacts and Impacts on Visibility

There are no Class I areas located within 100 km of the Project site. Therefore, long-range modeling analyses using more sophisticated techniques (such as the CALPUFF model) should not be required for this Project and are not included in this protocol.

The closest Class I area to the Project is the Brigantine Wilderness Area in New Jersey. The closest portion of the Brigantine Wilderness Area is approximately 206 km from the Project site. The next closest Class I area is the Lye Brook Wilderness Area in Vermont. The closest portion of this area is approximately 215 km from the Project site. Other Class I areas are well beyond 300 km from the Project site.

Given the potential to emit of the Project and the distance to the nearest Class I areas, it is expected that the Project will qualify for an exemption from potential Class I impact modeling requirements for air quality related values (AQRVs) and visibility. The Project has consulted with the Federal Land Managers for the nearest Class I areas to request a determination that the Project would be exempt from any Class I modeling requirement.

Even though the Project will likely be exempt from the need for any Class I impact modeling, a Level-1 visibility impact screening analysis using the EPA VISCREEN model with default assumptions will be conducted using maximum proposed short-term (lb/hr) emission rates of NO_x, PM, and primary sulfate as represented by sulfuric acid mist (H_2SO_4) emissions for the Project. The resulting visibility impacts inside the Brigantine Wilderness Area and the Lye Brook Wilderness Area due to maximum proposed emissions from the Project will be compared to the established default screening thresholds of 2.00 for plume perceptibility (Delta-E) and 0.05 for plume contrast.

The VISCREEN analysis will be conducted using the standard Level-1 default parameters. A visual range of 159 km for Brigantine Wilderness Area and 195 km for Lye Brook Wilderness Area will be used based on the annual average of monthly natural conditions visual range values provided in Table V.1-6 of the June 2008 draft "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report – Revised."

4.8.3 Class II Impacts on Visibility

NYSDEC has requested that a visibility impact analysis be conducted for the Catskills State Park. Class II areas are not subject to the stringent protection that is provided to Class I areas. Nonetheless, potential impacts on visibility due to Project emissions will be assessed for those locations for which impacts from the plume would be most likely to be discerned (i.e., from prominent elevation peaks throughout Catskills State Park).

The analysis will consider locations associated with all high peaks (those with elevations equal to or greater than 3500 feet MSL) in the Catskills State Park as identified on the Catskills GIS website). An observer will be assumed to be at the nearest peak to the Project, and a background visual range of 40 km will be assumed consistent with recommended values provided in Figure 4-3 of EPA's "Tutorial Package for the VISCREEN Model. Predicted Project impacts will be compared to the stringent Class I default screening threshold for plume perceptibility and plume contrast.

4.9 Environmental Justice

EPA and NYSDEC both have environmental justice (EJ) policies that require an evaluation of whether minority or low-income communities are affected adversely or disproportionately by the actions of federal agencies, including approvals under the PSD program.

One EJ area within a 2 mile radius of the Project has been identified. In addition, NYSDEC identified six additional EJ areas located in parts of Middletown located beyond 2 miles from the Project.

The EJ analysis will present isopleths or other visual displays showing the spatial pattern of predicted Project impacts so that impacts predicted within the EJ communities can be compared to impacts predicted elsewhere. The displays will allow conclusions to be drawn concerning whether the identified EJ areas would receive a disproportionate share of any adverse air quality related impacts.

4.10 Additional Analyses for SEQRA

Some additional modeling analyses will be conducted to satisfy NYSDEC requirements under the State Environmental Quality Review Act (SEQRA) process. These include analyses for: (1) impacts from an accidental release of ammonia; (2) analysis of the potential for visible water vapor plumes from the combined cycle stacks; and (3) potential for acidic deposition on sensitive receptors in New York identified in the State Acid Deposition Control Act (SADCA). Brief summaries of the proposed modeling for these analyses are provided in the following sections.

4.10.1 Accidental Ammonia Release

Aqueous ammonia will be stored on site for use in the SCR emissions control system for NO_x. An aqueous solution of less than 20 percent by weight will be stored in a 15,000 gallon tank. The tank will be located within an impermeable concrete containment area approximately 20 feet long and 20 feet wide and surrounded by a wall. The floor of the containment area will be covered with plastic balls designed to float on the liquid surface in the event of a spill. The plastic balls would reduce the surface area of the exposed liquid and thereby reduce the rate of evaporation of ammonia to the atmosphere in the event of an accidental release of aqueous ammonia from the tank.

Facilities that store aqueous ammonia solutions containing less than 20 percent ammonia by weight are not subject to the EPA Risk Management Planning (RMP) Rule. However, an analysis of potential impacts from a hypothetical ammonia tank failure will be conducted. The assessment will use the most recent version of the Areal Locations of Hazardous Atmosphere (ALOHA) model (version 5.6.1). ALOHA was developed by EPA and the National Oceanic and Atmospheric Administration (NOAA) and is designed for use for emergency response to chemical releases and for emergency planning and training.

Consistent with RMP Rule guidance, worst-case and alternate scenarios will be modeled. In each case, the total failure of the ammonia tank resulting in the spilling of tank contents into the containment area will be assumed. The worst-case scenario will assume F stability and a wind speed of 1.5 meters per second. The alternate scenario will assume D stability and a wind speed of 3.0 meters per second. Ambient temperatures for the worst-case and alternate scenarios will be selected based on an analysis of data from Orange County Airport.

ALOHA will be used to determine the downwind distances at which the ammonia concentration resulting from the hypothetical accidental releases would decrease to less than the Emergency Response Planning Guideline Level 2 (ERPG-2) threshold defined by the American Industrial Hygiene Association (AIHA) for ammonia, equal to 150 ppm. The predicted endpoint distances will be compared to the distance to the nearest "public receptor" as that term is defined in the RMP rule.

4.10.2 Potential for Visible Water Vapor Plumes From Combined Cycle Stacks

Water vapor in the combined cycle stack plumes may condense to form visible plumes under some atmospheric conditions. If the ambient air is cold and moist, a portion of the emitted water vapor will condense to form water droplets. This may produce a visible, white plume.

The potential for visible water vapor plumes from the combined cycle stacks will be assessed using the CALPUFF model. The concentrations of water vapor predicted by CALPUFF will be evaluated by the POSTPM processor to determine if the plume, when added to the ambient water vapor concentration, will have concentrations exceeding the saturation value. Under these conditions, the plume will be considered to be potentially visible.

The model will be run for the full 5-year meteorological period of record to obtain seasonal results regarding the frequency of water vapor plumes, their downwind extent, and height. Seasonal results will be obtained to bracket the expected range of visible vapor plume effects and to more accurately characterize the frequency of expected visible plumes. Results for summer conditions will be based on operating condition SF10, corresponding to operation at base load while firing natural gas with duct firing and evaporative cooling at an ambient temperature of 90 ^{o}F. This condition also has the highest water vapor emission rate. The results for winter conditions will be based on operating condition SG01, corresponding to base load operation while firing natural gas without duct firing at an ambient temperature of -5 ^{o}F, since there would normally be no need for duct firing at low ambient temperatures. Results for spring and fall conditions will be based on operating condition SG05, corresponding to operation at base load while firing natural gas at an ambient temperature of 51 ^{o}F with no evaporative cooling and with a reduced level of duct firing sufficient to satisfy the desired net power output for the Project.

The POSTPM processor provides tables that list each hour with a potentially visible plume along with any observed weather element. Hours with 100% relative ambient relative humidity, which have naturally occurring fog, will be excluded. Plumes predicted at night will also be excluded, since these would not be visible to an observer. Tables of visible plume lengths and heights by season will be produced indicating predicted frequency of occurrence.

4.10.3 Acidic Deposition on Sensitive Receptors

The assessment of potential acidic deposition on sensitive receptors identified in the SADCA will be conducted in accordance with procedures specified in a March 4, 1993 memorandum from Leon Sedefian (NYSDEC). Orange County will be identified as the reference source for the Project. The ratio of the maximum proposed annual Project emissions of NO_x and SO_2 to the reference source emissions will be used to scale the reference source acidic deposition impacts at the eighteen identified sensitive receptors. The Project impacts will be presented at each sensitive receptor for SO_2 in terms of grams per square meter per year and for NO_x in kilograms per hectare and as percentages of the total New York state acidic deposition.

4.11 Model Output Processing

Given the number of sources and operating scenarios to be modeled, total impacts in some analyses will be obtained by summing contributions from multiple emission units which will be modeled using unit emission rates. In order to process the information from the individual AERMOD model runs, an existing Fortran utility program will be used to convert hourly binary concentration file output from AERMOD to CALPUFF concentration file format. Then the CALPUFF postprocessors POSTUTIL and CALPOST will be used to compute total concentrations for specific source groupings for individual pollutants and averaging periods.

If required, an example case will be modeled using actual emission rates in AERMOD to demonstrate that the procedure of postprocessing provides equivalent results.

TABLES

Table 2-1: Project Potential to Emit

Pollutant	Potential to Emit (tons per year)					
	Combined Cycle Units	Auxiliary Boiler	Emergency Generator	Fire Water Pump	Fuel Gas Heaters	Total Facility
NO_x	174.89	3.31	5.80	0.49	2.53	187.0
CO	334.03	5.30	0.53	0.43	3.70	344.0
VOC	63.32	0.28	0.13	0.20	0.48	64.6
SO_2	41.00	0.16	0.01	0.00	0.10	41.3
$PM_{10}/PM_{2.5}$	94.15	0.46	0.04	0.02	0.33	95.0
H_2SO_4	12.60	0.012	0.000	0.000	0.007	12.6
Total HAP	13.77	0.13	0.015	0.0022	0.041	14.0
Individual HAP	2.55	0.13	0.005	0.0007	0.039	2.6

Notes:

1. Potential to emit for $PM_{10}/PM_{2.5}$ for facility and combined cycle units incorporates effect of proposed emissions cap.
2. Potential to emit for other pollutants based on maximum emissions over range of proposed operating conditions and does not include consideration of the effect of proposed emission cap on $PM_{10}/PM_{2.5}$.
3. Total facility potential to emit for VOC includes 0.17 tons per year from oil storage tank.
4. Individual HAP with maximum potential emissions for facility and for combined cycle units is toluene.
5. Individual HAP with maximum potential to emit for auxiliary boiler and fuel gas heaters is hexane.
6. Individual HAP with maximum potential to emit for emergency generator and fire water pump is formaldehyde.

Table 2-2: Project Potential to Emit and Regulatory Thresholds

Pollutant	Project Potential to Emit (tpy)	PSD Major Source Threshold (tpy)	NNSR Major Source Threshold (tpy)	Significant Emissions (tpy)
NO_x	187.0	100	100 [a]	40
CO	344.0	100	na	100
VOC	64.6	na	50 [a]	40
SO_2	41.3	100	100 [b]	40
PM_{10}	95.0	100	na	15
$PM_{2.5}$	95.0	na	100	10

Notes:

a. Precursor pollutants for ozone.

b. Precursor pollutant for $PM_{2.5}$ (applies only if source is major for $PM_{2.5}$).

Table 2-3: Combined Cycle Unit Operating Cases

Case ID	Fuel	Ambient Temperature (°F)	Turbine Load (%)	Evaporative Cooling	Duct Firing (MMBtu/hr)	Emission Rate (per unit)				Stack Exit Parameters	
						NO_x (g/s)	CO (g/s)	SO_2 (g/s)	PM (g/s)	Velocity (m/s)	Temperature (K)
SG01	Gas	-5	BASE	Off	--	2.117	1.285	0.614	1.400	22.1	363.7
SG02	Gas	-5	BASE	Off	500	2.621	2.545	0.751	2.086	22.2	363.7
SG03	Gas	-5	80%	Off	--	1.774	1.084	0.572	1.244	18.7	356.5
SG04	Gas	-5	60%	Off	--	1.441	3.503	0.426	1.184	15.6	354.8
SG05	Gas	51	BASE	Off	185.37	2.082	1.626	0.600	1.527	20.1	356.5
SG06	Gas	51	BASE	Off	500	2.399	2.419	0.686	1.959	20.2	356.5
SG07	Gas	51	BASE	Off	--	1.895	1.159	0.549	1.272	20.1	360.4
SG08	Gas	51	80%	Off	--	1.583	0.958	0.511	1.219	17.0	354.3
SG09	Gas	51	60%	Off	--	1.290	3.150	0.375	1.163	14.4	353.2
SG10	Gas	90	BASE	On	500	2.258	2.318	0.647	1.905	19.0	357.0
SG11	Gas	90	BASE	On	--	1.754	1.058	0.510	1.218	18.9	357.0
SG12	Gas	90	BASE	Off	500	2.208	2.293	0.647	1.905	19.0	364.3
SG13	Gas	90	BASE	Off	--	1.704	1.033	0.510	1.218	18.9	364.3
SG14	Gas	90	80%	Off	--	1.441	0.882	0.464	1.199	15.5	352.6
SG15	Gas	90	60%	Off	--	1.179	2.873	0.341	1.149	13.3	351.5
SF01	Oil	-5	BASE	Off		6.480	0.936	0.412	6.470	22.8	371.5
SF02	Oil	-5	85%	Off		5.634	1.714	0.359	5.692	19.9	362.0
SF03	Oil	-5	70%	Off		4.860	2.948	0.308	7.309	17.5	362.0
SF04	Oil	51	BASE	Off		5.724	1.159	0.364	5.820	20.6	368.7
SF05	Oil	51	85%	Off		5.022	1.537	0.319	5.172	18.0	358.2
SF06	Oil	51	70%	Off		4.338	2.646	0.276	6.666	16.0	358.2
SF07	Oil	90	BASE	On		5.310	1.084	0.337	5.305	19.2	368.2
SF08	Oil	90	BASE	Off		5.130	1.033	0.326	5.175	19.2	368.2
SF09	Oil	90	85%	Off		4.554	1.386	0.289	4.655	16.0	358.2
SF10	Oil	90	70%	Off		3.942	2.394	0.250	6.025	14.8	358.2

Notes:

1. PM emission rate applies to PM_{10} and $PM_{2.5}$.
2. Stack height = 275 ft (83.82 m).
3. Stack inner exit diameter = 19 ft (5.79 m).
4. Stack base elevation = 464 ft (141.4 m) MSL.

Table 2-4: Combined Cycle Unit Startup Emissions Scenarios

Fuel	Startup Event	Duration (hr)	Emissions Per Start (lb) CO	PM	SO_2	Velocity (m/s)	Temperature (K)	CO (g/s)	PM (g/s)	SO_2 (g/s)
Gas	Cold	2.158	580.7	20.9	6.4	7.2	318.4	36.584	1.314	0.404
Gas	Warm	1.617	539.3	15.6	4.8	7.2	318.4	42.028	1.216	0.375
Gas	Hot	1.383	456.1	13.0	4.1	7.2	318.4	41.544	1.184	0.375
Oil	Cold	2.325	752.1	123.4	5.1	8.0	320.9	47.382	7.771	0.321
Oil	Warm	1.783	670.1	93.5	3.9	8.0	320.9	47.345	6.603	0.276
Oil	Hot	1.550	572.8	80.9	3.4	8.0	320.9	46.559	6.572	0.276

Notes:

1. Short-term (g/s) emission rates for starts based on ratio of emissions per start to start duration.
2. Short-term (g/s) emission rates for cold starts are further scaled by (2.158/2) for gas firing and by (2.325/2) for oil firing to ensure that total emissions per start are not underestimated.

Table 2-5: Emergency Generator Stack and Emission Parameters

Pollutant	Short-term Emission Rate (g/s)	Annual Average Emission Rate (g/s)
NO_x	2.9231	0.16684
CO	0.2647	0.01511
SO_2	0.0027	0.00015
PM	0.0176	0.00101

Stack Height	15.24	meters
Inner Stack Diameter	0.457	meters
Exit Velocity	31.80	m/s
Exit Temperature	679.5	K
Stack Base Elevation	141.4	meters

Table 2-6: Auxiliary Boiler Stack and Emission Parameters

Pollutant	Short-term Emission Rate (g/s)	Annual Average Emission Rate (g/s)
NO_x	0.4171	0.0952
CO	0.6673	0.1523
SO_2	0.0202	0.0046
PM	0.0584	0.0133

Stack Height	83.82	meters
Inner Stack Diameter	5.79	meters
Exit Velocity	0.35	m/s
Exit Temperature	422.0	K
Stack Base Elevation	141.4	meters

Table 2-7: Fire Water Pump Stack and Emission Parameters

Pollutant	Short-term Emission Rate (g/s)	Annual Average Emission Rate (g/s)
NO_x	0.2457	0.0140
CO	0.2150	0.0123
SO_2	0.0004	0.000023
PM	0.0123	0.0007

Stack Height	15.24	meters
Inner Stack Diameter	0.15	meters
Exit Velocity	41.52	m/s
Exit Temperature	784.3	K
Stack Base Elevation	142.6	meters

Table 2-8: Fuel Gas Heater Stack and Emission Parameters

Pollutant	Short-term Emission Rate (g/s)	Annual Average Emission Rate (g/s)
NO_x	0.0727	0.0727
CO	0.1063	0.1063
SO_2	0.0028	0.0028
PM	0.0096	0.0096

Note: Emission rates represent two heaters.

Stack Height	38.10	meters
Inner Stack Diameter	0.61	meters
Exit Velocity	4.90	m/s
Exit Temperature	727.6	K
Stack Base Elevation	141.4	meters

Table 2-9: Proposed Stack Locations

Stack	UTM East Coordinate (m)	UTM North Coordinate (m)
Combined Cycle Unit - N	546,980.48	4,584,692.87
Combined Cycle Unit - S	546,990.53	4,584,654.55
Auxiliary Boiler	546,990.53	4,584,654.55
Emergency Generator	547,129.88	4,584,651.45
Fire Water Pump	546,815.02	4,584,669.44
Fuel Gas Heater	546,958.85	4,584,580.55

Notes: Coordinates are in UTM Zone 18, North American Datum of 1983 (NAD 83).

Table 2-10: Largest Proposed Buildings and Structures

Structure	Structure ID	Base Elevation (feet)	Height Above Grade (feet)	Structure Length (feet)	Structure Width (feet)	Structure Diameter (feet)
Air Cooled Condenser	13	464	115	303	267	-
Aux Fin Fan Cooler	18	464	11	101	41	-
Fire Water Pump Bldg.	21	464	13	22	10	-
Ammonia Tank	23	464	17	-	-	11
Combustion Turbine Bldg.	24	464	113	304	263	-
Water Treatment Bldg.	28	468	32	123	60	-
Steam Turbine Generator Bldg.	32	464	102	220	202	-
Diesel Generator Bldg.	38	464	23	39	22	-
Process Water Sump Bldg.	43	464	24	37	30	-
Air Intake Filter Extension (N)	47N	464	93	58	40	-
Air Intake Filter Extension (S)	47S	464	93	57	41	-
Fuel Oil Tank	Tank 16	464	47	-	-	60
Reclaim/Fire Water Storage Tank	Tank 19	464	26	-	-	84
Demineralized Water Tank	Tank 20	464	20	-	-	60

Notes:

1. Structure dimensions are approximate and have been rounded to the nearest foot in the table.
2. Listed structures are those that are included in the BPIP analysis.
3. Some complex structures have been simplified or idealized for treatment by BPIP.
4. Tanks represented by 16-sided polygons in BPIP.

Table 3-1: Data Capture and Acceptance Percentages for Surface Level Meteorological Observations

Year	Wind Speed	Wind Direction	Ceiling Height	Dry Bulb Temperatature	Relative Humidity	Surface Pressure
2002	99.62	95.66	99.82	99.53	99.46	99.75
2003	99.09	96.07	99.59	98.00	97.71	99.46
2004	99.67	95.38	99.72	99.62	99.61	99.62
2005	98.88	94.41	99.78	97.82	97.68	99.76
2006	99.36	95.56	99.90	99.50	99.50	99.89

Notes: Data capture rates for hourly observations from Orange County Airport (MGJ).

Table 3-2: Comparison of Surface Parameters for Orange County Airport and Project Site

Month	Orange County Airport Surroundings			Project Site Surroundings			Ratio of Surface Parameters		
	Albedo (r_a)	Bowen Ratio (Bo_a)	Surface Roughness (meters) (zo_a)	Albedo (r_s)	Bowen Ratio (Bo_s)	Surface Roughness (zo_s)	Albedo (r_s/r_a)	Bowen Ratio (Bo_s/Bo_a)	Surface Roughness (meters) ($\ln(zo_s)/\ln(zo_a)$)
1	0.17	0.79	0.104	0.17	0.84	0.067	1.00	1.06	1.19
2	0.17	0.79	0.104	0.17	0.84	0.067	1.00	1.06	1.19
3	0.17	0.79	0.104	0.17	0.84	0.067	1.00	1.06	1.19
4	0.15	0.48	0.139	0.15	0.52	0.097	1.00	1.08	1.18
5	0.15	0.48	0.139	0.15	0.52	0.097	1.00	1.08	1.18
6	0.17	0.39	0.228	0.17	0.43	0.287	1.00	1.10	0.84
7	0.17	0.39	0.228	0.17	0.43	0.287	1.00	1.10	0.84
8	0.17	0.39	0.228	0.17	0.43	0.287	1.00	1.10	0.84
9	0.17	0.39	0.228	0.17	0.43	0.287	1.00	1.10	0.84
10	0.17	0.78	0.217	0.17	0.84	0.285	1.00	1.08	0.82
11	0.17	0.78	0.217	0.17	0.84	0.285	1.00	1.08	0.82
12	0.17	0.78	0.104	0.17	0.84	0.067	1.00	1.08	1.19
Ann. Avg.	0.17	0.60	0.170	0.17	0.65	0.182	1.00	1.08	1.01

Notes:
1. Subscript "a" refers to airport location and subscript "s" refers to project site.
2. Monthly average values of albedo and Bowen ratio based on 10 km x 10 km area centered on airport or project site.
3. Monthly average values of surface roughess averaged over a single sector.
4. The comparison of surface roughness lengths is based on the ratio of the natural log of the values due to use of inverse-distance geometric weighted means in the calculation of zo.
5. Annual averages are arithmetic averages of the twelve monthly values.

Table 4-1: Worst-Case Impacts for Combined Cycle Units

Case ID	Fuel	Ambient Temperature (°F)	Turbine Load (%)	Evaporative Cooling	Duct Firing (MMBtu/hr)	Emission Rate (per unit) NO_x (g/s)	Emission Rate (per unit) CO (g/s)	Emission Rate (per unit) SO_2 (g/s)	Emission Rate (per unit) PM (g/s)	Stack Exit Parameters Velocity (m/s)	Stack Exit Parameters Temperature (K)	Maximum X/Q (ug/m^3)/(g/s) 1-hour	3-hour	8-hour	24-hour	Annual	Maximum Concentration (ug/m^3) 1-hour Maximum CO	1-hour Maximum SO_2	1-hour Maximum PM	3-hour SO_2	8-hour CO	24-hour SO_2	24-hour PM	Annual NO_x	Annual SO_2	Annual PM
SG01	Gas	-5	BASE	Off	--	2.117	1.285	0.614	1.400	22.1	363.7	10.024	3.737	2.333	0.778	0.037	12.88	6.15	14.03	2.29	3.00	0.48	1.09	0.08	0.023	0.052
SG02	Gas	-5	BASE	Off	500	2.621	2.545	0.751	2.086	22.2	363.7	9.739	3.710	2.315	0.772	0.037	24.79	7.31	20.32	2.79	5.89	0.58	1.61	0.10	0.028	0.078
SG03	Gas	-5	80%	Off	--	1.774	1.084	0.572	1.244	18.7	356.5	10.490	5.157	2.673	0.891	0.050	11.37	6.00	13.05	2.95	2.90	0.51	1.11	0.09	0.029	0.063
SG04	Gas	-5	60%	Off	--	1.441	3.503	0.426	1.184	15.6	354.8	11.546	6.627	3.314	1.107	0.065	40.44	4.92	13.67	2.82	11.61	0.47	1.31	0.09	0.028	0.077
SG05	Gas	51	BASE	Off	185.37	2.082	1.626	0.600	1.527	20.1	356.5	10.101	4.670	2.579	0.860	0.045	16.43	6.06	15.42	2.80	4.19	0.52	1.31	0.09	0.027	0.069
SG06	Gas	51	BASE	Off	500	2.399	2.419	0.686	1.959	20.2	356.5	10.383	4.648	2.574	0.858	0.045	25.12	7.13	20.34	3.19	6.23	0.59	1.681	0.108	0.031	0.088
SG07	Gas	51	BASE	Off	--	1.895	1.159	0.549	1.272	20.1	360.4	10.148	4.459	2.511	0.837	0.044	11.76	5.57	12.91	2.45	2.91	0.46	1.06	0.08	0.024	0.056
SG08	Gas	51	80%	Off	--	1.583	0.958	0.511	1.219	17.0	354.3	11.620	5.997	2.999	1.002	0.058	11.13	5.94	14.16	3.07	2.87	0.51	1.22	0.09	0.030	0.071
SG09	Gas	51	60%	Off	--	1.290	3.150	0.375	1.163	14.4	353.2	12.140	7.545	3.773	1.260	0.074	38.24	4.55	14.11	2.83	11.89	0.47	1.46	0.10	0.028	0.086
SG10	Gas	90	BASE	On	500	2.258	2.318	0.647	1.905	19.0	357.0	10.210	5.007	2.643	0.881	0.049	23.67	6.61	19.45	3.24	6.13	0.57	1.678	0.110	0.032	0.093
SG11	Gas	90	BASE	On	--	1.754	1.058	0.510	1.218	18.9	357.0	10.279	5.047	2.644	0.881	0.049	10.88	5.24	12.52	2.57	2.80	0.45	1.07	0.09	0.025	0.060
SG12	Gas	90	BASE	Off	500	2.208	2.293	0.647	1.905	19.0	364.3	9.999	4.587	2.526	0.842	0.045	22.93	6.47	19.05	2.97	5.79	0.54	1.60	0.10	0.029	0.086
SG13	Gas	90	BASE	Off	--	1.704	1.033	0.510	1.218	18.9	364.3	10.303	4.625	2.543	0.848	0.046	10.65	5.25	12.55	2.36	2.63	0.43	1.03	0.08	0.023	0.056
SG14	Gas	90	80%	Off	--	1.441	0.882	0.464	1.199	15.5	352.6	11.735	6.822	3.412	1.139	0.067	10.35	5.44	14.07	3.17	3.01	0.53	1.37	0.10	0.031	0.080
SG15	Gas	90	60%	Off	--	1.179	2.873	0.341	1.149	13.3	351.5	12.083	7.941	3.971	1.326	0.083	34.71	4.13	13.88	2.71	11.41	0.45	1.52	0.10	0.028	0.096
SUGC	Gas	Cold Startup					36.584	0.404	1.314	7.2	318.4	11.964					*437.71*	*4.84*	*15.72*							
SUGW	Gas	Warm Startup					42.028	0.375	1.216	7.2	318.4	11.964					*502.84*	*4.48*	*14.55*							
SUGH	Gas	Hot Startup					41.544	0.375	1.184	7.2	318.4	11.964					*497.04*	*4.48*	*14.17*							

Case ID	Fuel	Ambient Temperature (°F)	Turbine Load (%)	Evaporative Cooling	Duct Firing (MMBtu/hr)	Emission Rate (per unit) NO_x (g/s)	Emission Rate (per unit) CO (g/s)	Emission Rate (per unit) SO_2 (g/s)	Emission Rate (per unit) PM (g/s)	Stack Exit Parameters Velocity (m/s)	Stack Exit Parameters Temperature (K)	Maximum X/Q (ug/m^3)/(g/s) 1-hour	3-hour	8-hour	24-hour	Annual	Maximum Concentration (ug/m^3) 1-hour Maximum CO	1-hour Maximum SO_2	1-hour Maximum PM	3-hour SO_2	8-hour CO	24-hour SO_2	24-hour PM	Annual NO_x	Annual SO_2	Annual PM
SF01	Oil	-5	BASE	Off		6.480	0.936	0.412	6.470	22.8	371.5	8.719	3.240	2.117	0.706	0.034	8.16	3.59	56.41	1.34	1.98	0.29	4.56	0.22	0.014	0.218
SF02	Oil	-5	85%	Off		5.634	1.714	0.359	5.692	19.9	362.0	9.989	4.429	2.508	0.836	0.043	17.12	3.58	56.86	1.59	4.30	0.300	4.76	0.24	0.016	0.247
SF03	Oil	-5	70%	Off		4.860	2.948	0.308	7.309	17.5	362.0	10.523	5.292	2.669	0.890	0.052	31.03	3.25	76.92	1.63	7.87	0.27	6.50	0.25	0.016	0.381
SF04	Oil	51	BASE	Off		5.724	1.159	0.364	5.820	20.6	368.7	9.815	3.911	2.367	0.789	0.039	11.38	3.57	57.12	1.42	2.74	0.29	4.59	0.22	0.014	0.228
SF05	Oil	51	85%	Off		5.022	1.537	0.319	5.172	18.0	358.2	10.701	5.335	2.695	0.898	0.052	16.45	3.42	55.34	1.70	4.14	0.29	4.65	0.26	0.017	0.269
SF06	Oil	51	70%	Off		4.338	2.646	0.276	6.666	16.0	358.2	11.703	6.186	3.094	1.033	0.061	30.97	3.23	78.01	1.71	8.19	0.28	6.89	0.26	0.017	0.406
SF07	Oil	90	BASE	On		5.310	1.084	0.337	5.305	19.2	368.2	10.363	4.351	2.468	0.823	0.043	11.23	3.50	54.98	1.47	2.67	0.28	4.36	0.23	0.015	0.229
SF08	Oil	90	BASE	Off		5.130	1.033	0.326	5.175	19.2	368.2	10.363	4.351	2.468	0.823	0.043	10.71	3.38	53.62	1.42	2.55	0.27	4.26	0.22	0.014	0.224
SF09	Oil	90	85%	Off		4.554	1.386	0.289	4.655	16.0	358.2	11.692	6.178	3.090	1.032	0.061	16.21	3.38	54.43	1.79	4.28	0.298	4.80	0.28	0.018	0.283
SF10	Oil	90	70%	Off		3.942	2.394	0.250	6.025	14.8	358.2	11.666	6.817	3.409	1.138	0.068	27.93	2.92	70.29	1.71	8.16	0.28	6.86	0.27	0.017	0.408
SUFC	Oil	Cold Startup					47.382	0.321	7.771	8.0	320.9	11.818					*559.97*	*3.79*	*91.84*							
SUFW	Oil	Warm Startup					47.345	0.276	6.603	8.0	320.9	11.818					*559.54*	*3.26*	*78.03*							
SUFH	Oil	Hot Startup					46.559	0.276	6.572	8.0	320.9	11.818					*550.24*	*3.26*	*77.67*							

Note:

1. Maximum concentrations in ug/m^3 reflect operation of both combined cycle units.
2. Maximum annual impacts for oil firing reflect 8,760 hours of operation; oil firing will be limited to the equivalent of 720 hours per year per unit, so annual contribution of oil firing should be scaled by the factor (720/8760).
3. Shading identifies maximum normal emission rate for particular pollutant and fuel or maximum impact for combination of pollutant/averaging/fuel.

Table 4-2: Worst-Case Normal Operating Cases for Combined Cycle Units

Fuel	Pollutant	Averaging Period	Maximum Normal Emissions Case	Maximum Normal Impact Cases
Gas	NO_x	Annual	SG02	SG10
Gas	CO	1-hour	SG04	SG04
Gas	CO	8-hour	SG04	SG09
Gas	SO_2	3-hour	SG02	SG10
Gas	SO_2	24-hour	SG02	SG06
Gas	SO_2	Annual	SG02	SG10
Gas	PM_{10} / $PM_{2.5}$	24-hour	SG02	SG06
Gas	PM_{10} / $PM_{2.5}$	Annual	SG02	SG15
Oil	NO_x	Annual	SF01	SF09
Oil	CO	1-hour	SF03	SF03
Oil	CO	8-hour	SF03	SF06
Oil	SO_2	3-hour	SF01	SF09
Oil	SO_2	24-hour	SF01	SF02
Oil	SO_2	Annual	SF01	SF09
Oil	PM_{10} / $PM_{2.5}$	24-hour	SF03	SF06
Oil	PM_{10} / $PM_{2.5}$	Annual	SF03	SF10

Notes:

1. Combined cycle unit operating cases defined in Table 2-3.
2. Worst-case operating condition selected based on maximum predicted impact of normal operating cases.
3. Cold startup case for combined cycle units will be included in worst-case modeling for CO (1-hour and 8-hour) and for PM (24-hour, for oil firing).

Table 4-3: Ambient Air Quality Standards, Increments, Significance Levels, and Significant Monitoring Concentrations

Pollutant	Averaging Period	Significant Impact Level (μg/m^3)	National Ambient Air Quality Standard (μg/m^3)	New York Ambient Air Quality Standard (μg/m^3)	Class II PSD Increment (μg/m^3)	Significant Monitoring Concentration [h, i, k] (μg/m^3)
NO_2	annual	1	100	100	25	14
CO	1-hour	2,000	40,000	40,000	none	none
CO	8-hour	500	10,000	10,000	none	575
SO_2	3-hour	25	1,300	1,300	512	none
SO_2	24-hour	5	365	365	91	13
SO_2	Annual	1	80	80	20	none
PM_{10}	24-hour	5	150	none	30	10
PM_{10}	annual	1	50 [b]	none	17	none
$PM_{2.5}$	24-hour	none [a, f]	35	none	none [c]	none [e]
$PM_{2.5}$	annual	none [a, g]	15	none	none [d]	none [f]
Suspended Particulate	24-hour	none	none	250	none	none
Suspended Particulate	annual	none	none	45 [j]	none	none
Beryllium	k	none	none	0.01	none	none
Pb	3-month	none	1.5	none	none	0.1

Notes:

a. NESCAUM recommended a 24-hour SIL of 2 ug/m^3 for interim use until $PM_{2.5}$ SILs are established by EPA.
NESCAUM later indicated support for a more stringent level (1.2 ug/m^3) in comments on EPA's proposed range of SILs (see footnote f).
NYSDEC Interim Policy (CP-33) incorporates SIL-like thresholds of 5 ug/m^3 (24-hour) and 0.3 ug/m^3 (annual).

b. Prior annual PM_{10} standard of 50 ug/m^3 has been revoked by USEPA but remains in effect until $PM_{2.5}$ stndard is fully implemented.

c. EPA has proposed a 24-hour Class II increment of 9 ug/m^3 for $PM_{2.5}$, but no final rulemaking has occurred.

d. EPA has proposed annual Class II increment limits of 5 and 4 ug/m^3 for $PM_{2.5}$, but no final rulemaking has occurred.

e. EPA has proposed 24-hour Class II SMCs of 10, 8.0, and 2.3 ug/m^3 for $PM_{2.5}$, but no final rulemaking has occurred.

f. EPA has proposed 24-hour SILs of 5.0, 4.0, and 1.2 ug/m^3 for $PM_{2.5}$, but no final rulemaking has occurred.

g. EPA has proposed annual SILs of 1.0, 0.8, and 0.3 ug/m^3 for $PM_{2.5}$, but no final rulemaking has occurred.

h. Additional SMCs have been defined for mercury (0.25 ug/m^3 for 24-hour averaging period) and vinyl chloride (15 ug/m^3 for 24-hour period).

i. NYSDEC has established additional ambient standards for the following pollutants that will not be emitted by the Project: gaseous fluorides, hydrogen sulfide, and settleable particulates.

j. Assumes that most stringent standard associated with Level I area applies.

k. EPA has also established SMCs for the other non-criteria pollutants that will not be emitted by the Project (fluorides, total reduce sulfur, hydrogen sulfide, and reduced sulfur compounds).

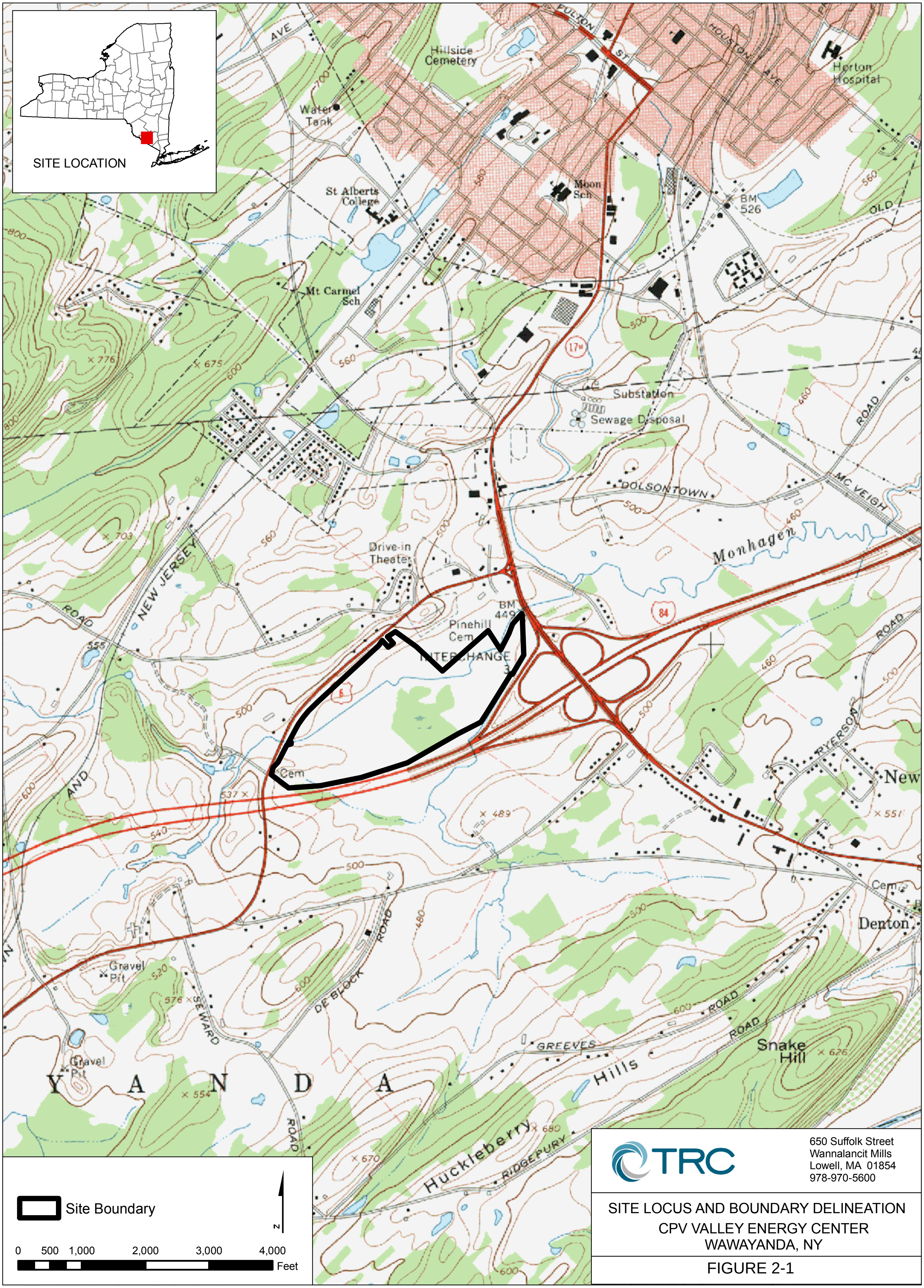
Table 4-4: Background Air Quality

Pollutant	Averaging Period	Units	Ambient Concentration				Monitor Location	Location Relative To Project
			2004	2005	2006	2007		
CO	1-hour	ppm	-	**3.4**	2.9	2.2	Hackensack, Bergen County, NJ	42 miles SSE
CO	8-hour	ppm	-	**2.8**	2.2	1.8	Hackensack, Bergen County, NJ	42 miles SSE
SO_2	3-hour	ppm	-	**0.021**	0.018	0.017	NYSDEC Field HQ, Gypsy Trail Road, Putnam Co., NY	38 miles E
SO_2	24-hour	ppm	-	0.010	**0.011**	0.009	NYSDEC Field HQ, Gypsy Trail Road, Putnam Co., NY	38 miles E
SO_2	Annual	ppm	-	**0.002**	**0.002**	**0.002**	NYSDEC Field HQ, Gypsy Trail Road, Putnam Co., NY	38 miles E
PM_{10}	24-hour	ug/m^3	-	**78**	71	59	Fort Lee, Bergen Co., NJ	46 miles S to SSE
PM_{10}	Annual	ug/m^3	-	**35**	34	33	Fort Lee, Bergen Co., NJ	46 miles S to SSE
$PM_{2.5}$	24-hour	ug/m^3	-	29.6	27.5	30.4	Newburgh, Orange Co., NY	23 miles ENE
$PM_{2.5}$	Annual	ug/m^3	-	12.1	9.7	10.6	Newburgh, Orange Co., NY	23 miles ENE
NO_2	Annual	ppm	0.020	**0.022**	0.019	-	Fairleigh Dickinson University, Teaneck, Bergen Co., NJ	42 miles S to SSE
Pb	3-month	ug/m^3	-	**0.11**	0.03	0.03	Walkill, Orange Co., NY	5 miles NE
O_3	1-hour	ppm	-	0.107	0.094	0.131	Montgomery, Orange Co., NY	14 miles NE to ENE
O_3	8-hour	ppm	-	0.087	0.077	0.084	Montgomery, Orange Co., NY	14 miles NE to ENE

Notes:

1. Highest second-highest short-term and maximum annual average concentrations presented, except for 24-hour $PM_{2.5}$ (98th percentile concentration) and 8-hour O_3 (fourth high).
2. Pb concentrations are maximum quarterly value in each year.
3. Bold value identifies maximum value over most recent 3-year period of available data.
4. Representative background values for $PM_{2.5}$ and O_3 discussed in text.

FIGURES



650 Suffolk Street
Wannalancit Mills
Lowell, MA 01854
978-970-5600

SITE LOCUS AND BOUNDARY DELINEATION
CPV VALLEY ENERGY CENTER
WAWAYANDA, NY

FIGURE 2-1

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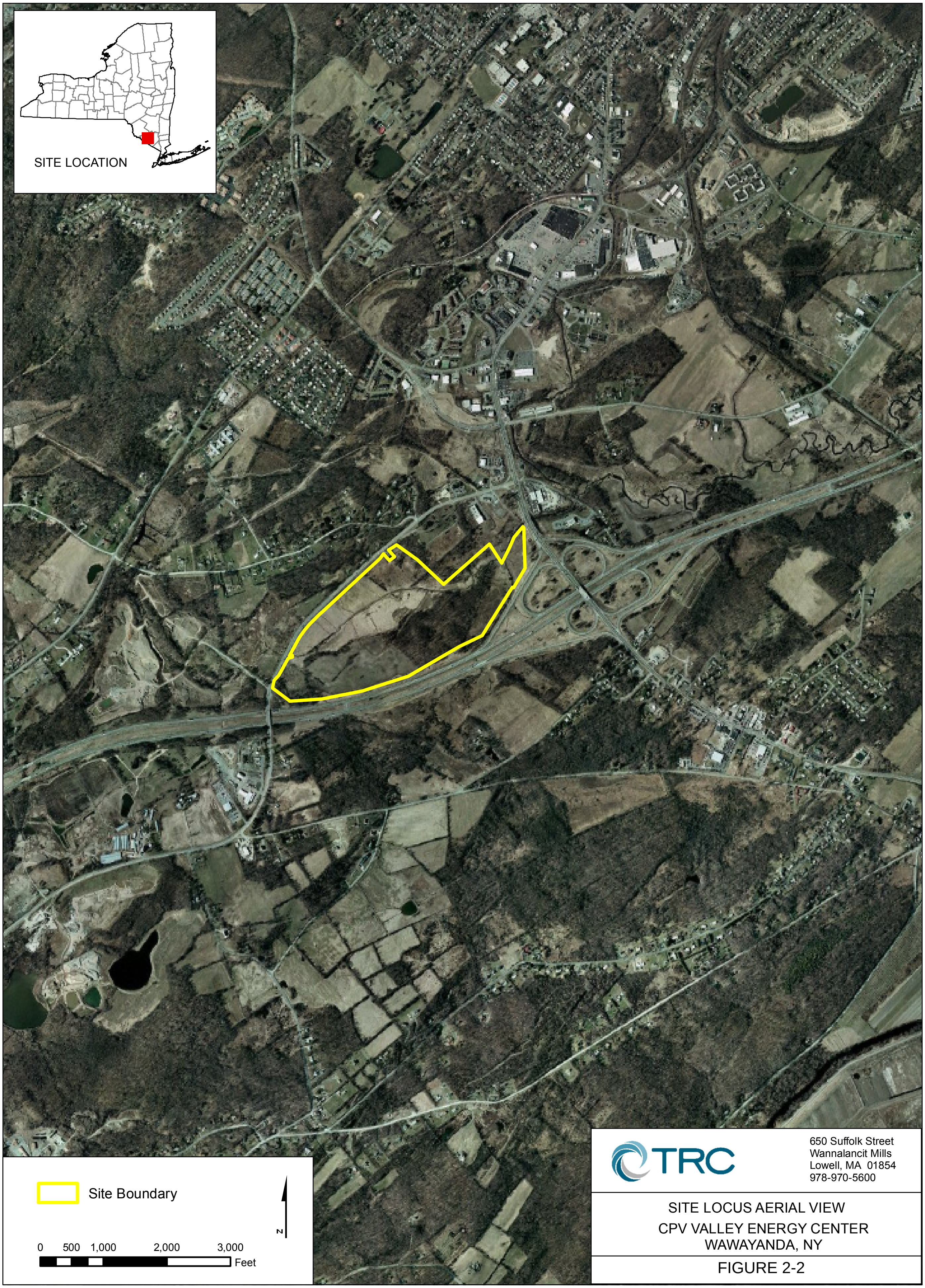


R:\Projects\GIS_2007\150338_Wawayonda\mxd\Figures\FIGURE2_060308.mxd

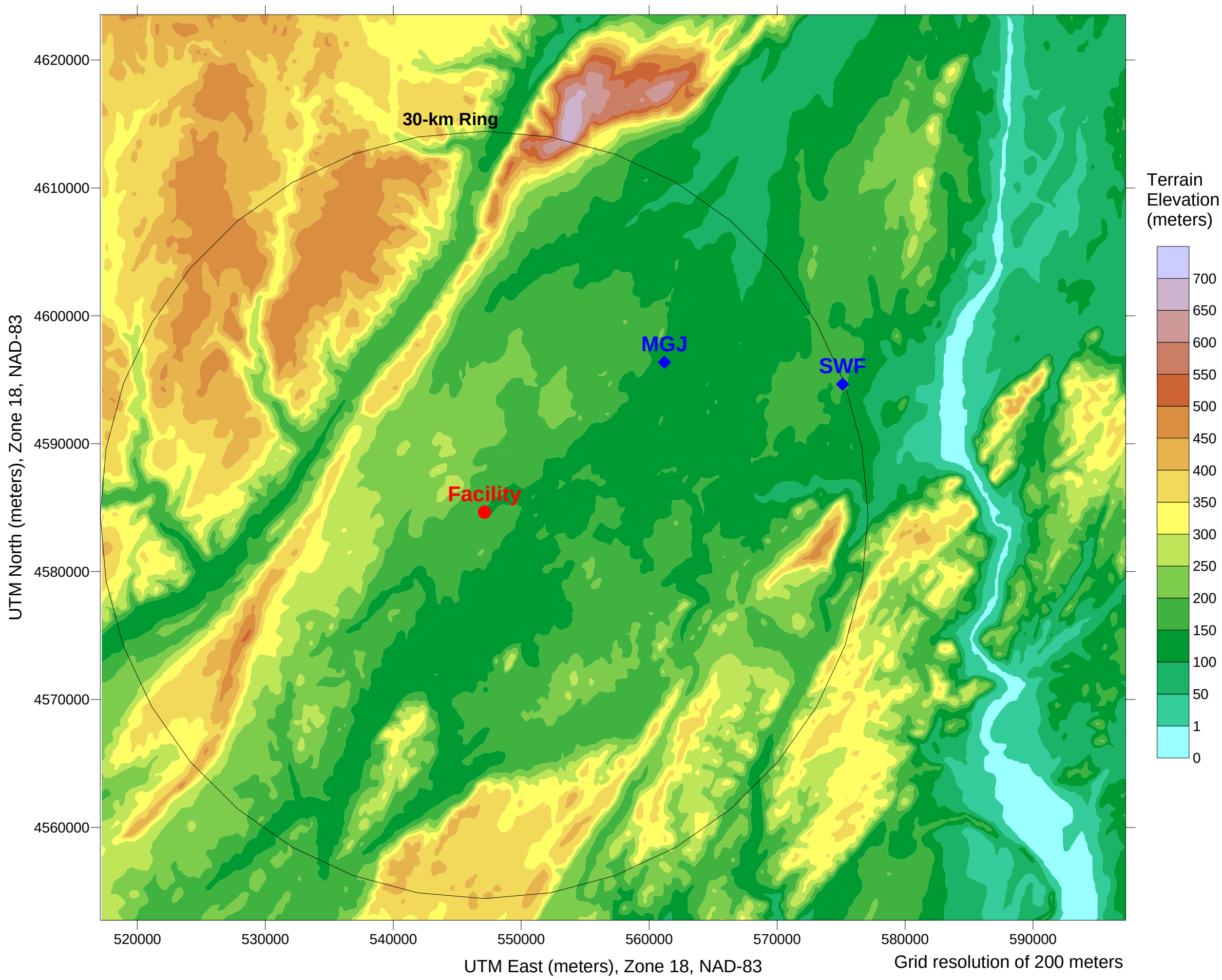
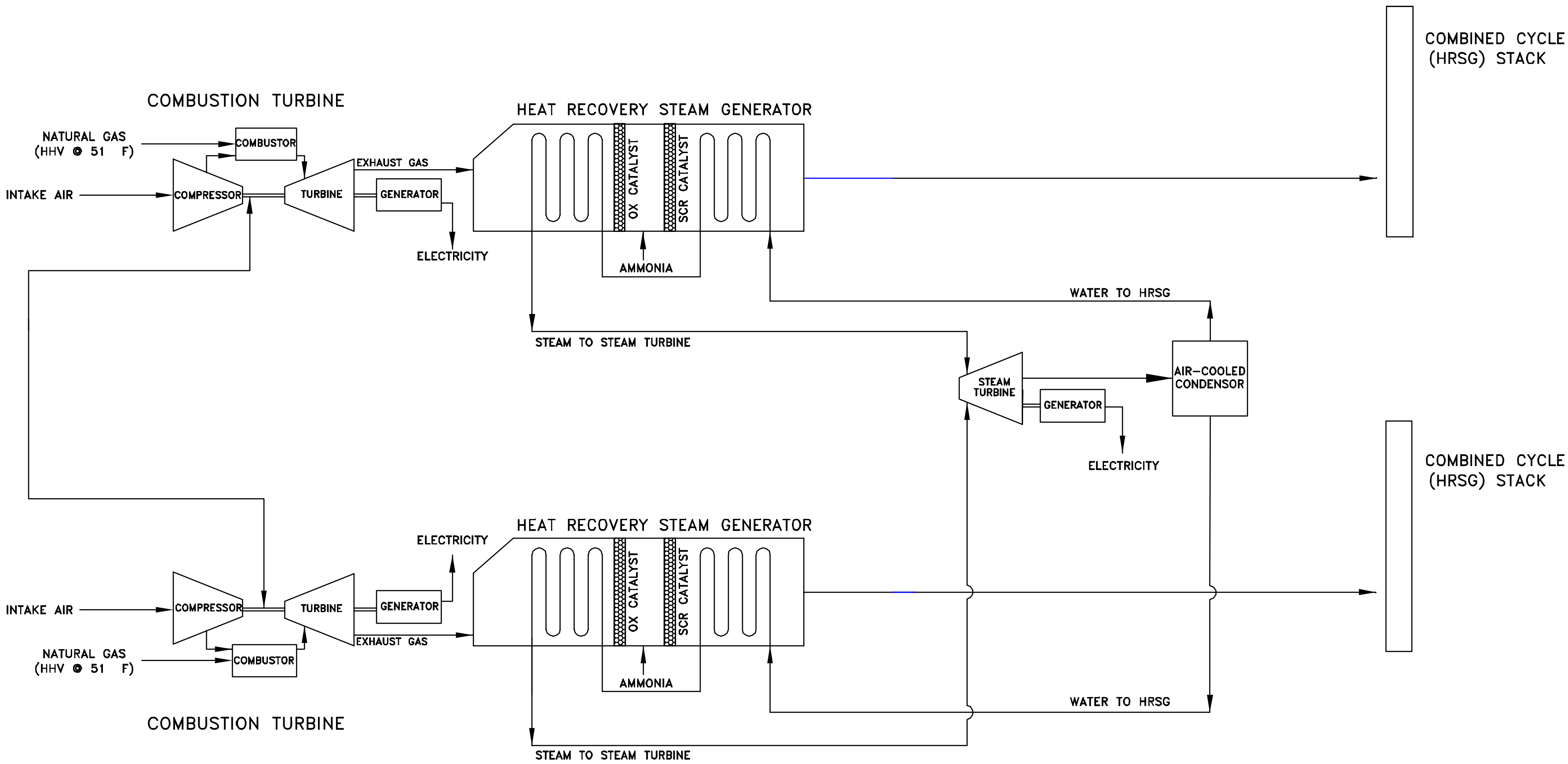


Figure 2-3 Terrain elevations derived from 90-meter USGS Digital Elevation Model data and interpolated to a 200-meter grid. The locations of the proposed facility, Orange County Airport (MGJ), and Stewart International Airport (SWF) are noted.



CPV VALLEY ENERGY CENTER
WAWAYANDA, NEW YORK

CONCEPTUAL FLOW DIAGRAM
FOR A COMBINED CYCLE FACILITY

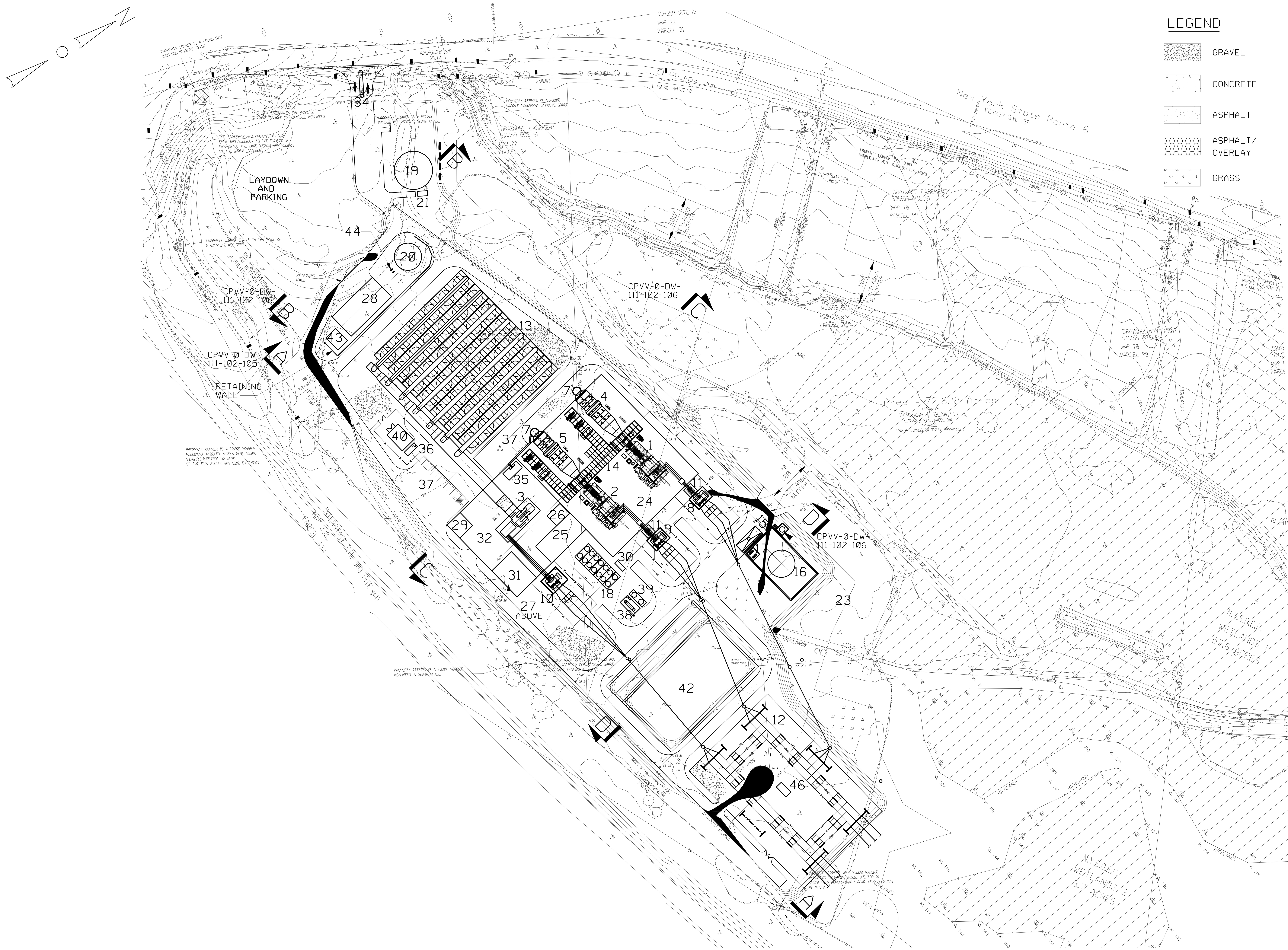
TRC
Wannalancit Mills
650 Suffolk Street
Lowell, MA 01854
(978) 970-5600

FIGURE 2-4

DATE:
Nov. 2007

FILE: T:\E_CAD\150338\CONCEPT_FLOW(3-4).dwg

Figure 2-5: Proposed Layout of Stacks and Major Buildings on Site



LEGEND

- GRAVEL
- CONCRETE
- ASPHALT
- ASPHALT/OVERLAY
- GRASS

EQUIPMENT DESCRIPTION

1 CTG #1
2 CTG #2
3 STG
4 HRSG #1
5 HRSG #2
6 NOT USED
7 HRSG STACK
8 GSU TRANSFORMER #1
9 GSU TRANSFORMER #2
10 GSU TRANSFORMER #3
11 AUXILIARY TRANSFORMER
12 SWITCHYARD
13 AIR COOLED CONDENSER
14 PIPE RACK
15 TRUCK UNLOADING AREA
16 FUEL OIL TANK
17 FUEL OIL PUMPS
18 AUXILIARY FIN-FAN COOLER
19 RECALIM/FIRE WATER STG TK (1,000,000 GAL)
20 DEMINERALIZED WATER TK (400,000 GAL)
21 FIRE WATER PUMP BUILDING
22 WTR TRT LV SWITCHGEAR & XFMRS
23 AQUEOUS AMMONIA TANK & PUMPS
24 COMBUSTION TURBINE BUILDING
25 ELECTRICAL EQUIPMENT ROOM
26 CONTROL ROOM
27 ADMINISTRATION OFFICES
28 WATER TREATMENT BUILDING
29 MAINTENANCE
30 OILY WATER SEPARATOR
31 WAREHOUSE
32 STEAM TURBINE GENERATOR BUILDING
33 PERIMETER FENCING
34 MAIN PLANT ENTRANCE/GUARD SHACK
35 AUX. BOILER
36 DEW POINT HEATER
37 PLANT PARKING
38 DIESEL GENERATOR
39 DIESEL GENERATOR AUX COOLER
40 NATURAL GAS METER. & FILTER AREA
41 NOT USED
42 STORM WATER POND
43 PROCESS WATER SUMP
44 CONDENSATE MAKE-UP PUMPS
45 NOT USED
46 SWITCHYARD CONTROL BLDG.

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH. SPEC.	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
H	05 01 08	REMOVED SIEMENS FROM TITLE BLOCK	RAK		JEV				HNG
G	02 20 08	ADDED SIEMENS SGT6-5000F IN LIEW OF GE 7FA, REVISED SWITCHYARD ORIENTATION	JEV		JEV				HNG
F	02 01 08	REVISED SWITCHYARD AND ADDED LEGEND	JEV		JEV				HNG
E	01 04 08	UPDATED TO INCORPORATE COMMENTS	JEV		JEV				HNG
D	11 08 07	ADDED ELEVATION REFERENCES	JEV		JEV				HNG
C	10 31 07	GENERAL REVISION	JEV		JEV				HNG
B	10 22 07	OVERALL UPDATE FOR REVIEW	JEV		JEV				HNG
J	10 06 08	INCORPORATED COMMENTS	JEV		JEV				HNG

PRELIMINARY STATUS DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
LDE

APPROVED STATUS DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
LDE

ORIGINATING PERSONNEL | PROFESSIONAL ENGINEER'S SEAL

DRAWN BY: JEV
CHECKED BY:
LEAD DESIGNER: JE VEEN
ENGINEER/TECH SPECIALIST:
PROJECT ENGINEERING MANAGER:
PROJECT MANAGER: HN GOLDSTEIN

Zero Harm — Leadership No Incidents Safe Behavior

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE: ______ STATE: ______
LIC. NO.: ______ DATE: ______

WorleyParsons
resources & energy

CLIENT/PROJECT TITLE
CPV VALLEY LLC
CPV VALLEY ENERGY CENTER

FIGURE 2-6

GENERAL ARRANGEMENT
SITE PLAN
2x1 COMBINED CYCLE

SCALE: 1"=100'
DRAWING SIZE: ARCH D (36" x 24")
WORLEYPARSONS DWG. NO.: CPVV-Ø-DW-111-002-101
REV: J

CONCEPTUAL DESIGN STUDY
FOR REVIEW ONLY

100 0 100 200 300
SCALE: 1" = 100'

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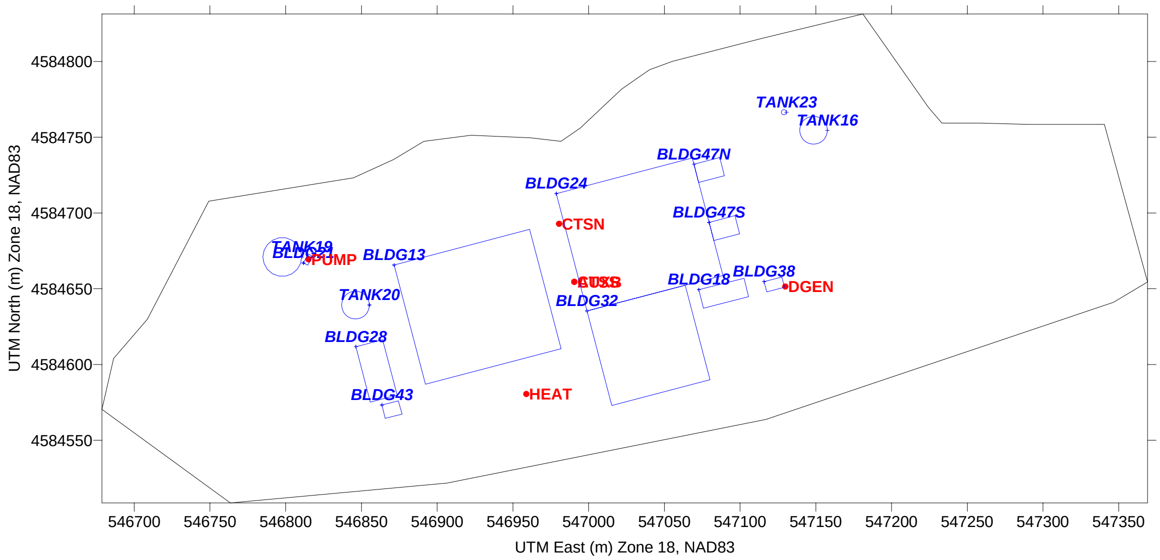


Figure 3-1: Fence Line, Stacks, and Buildings

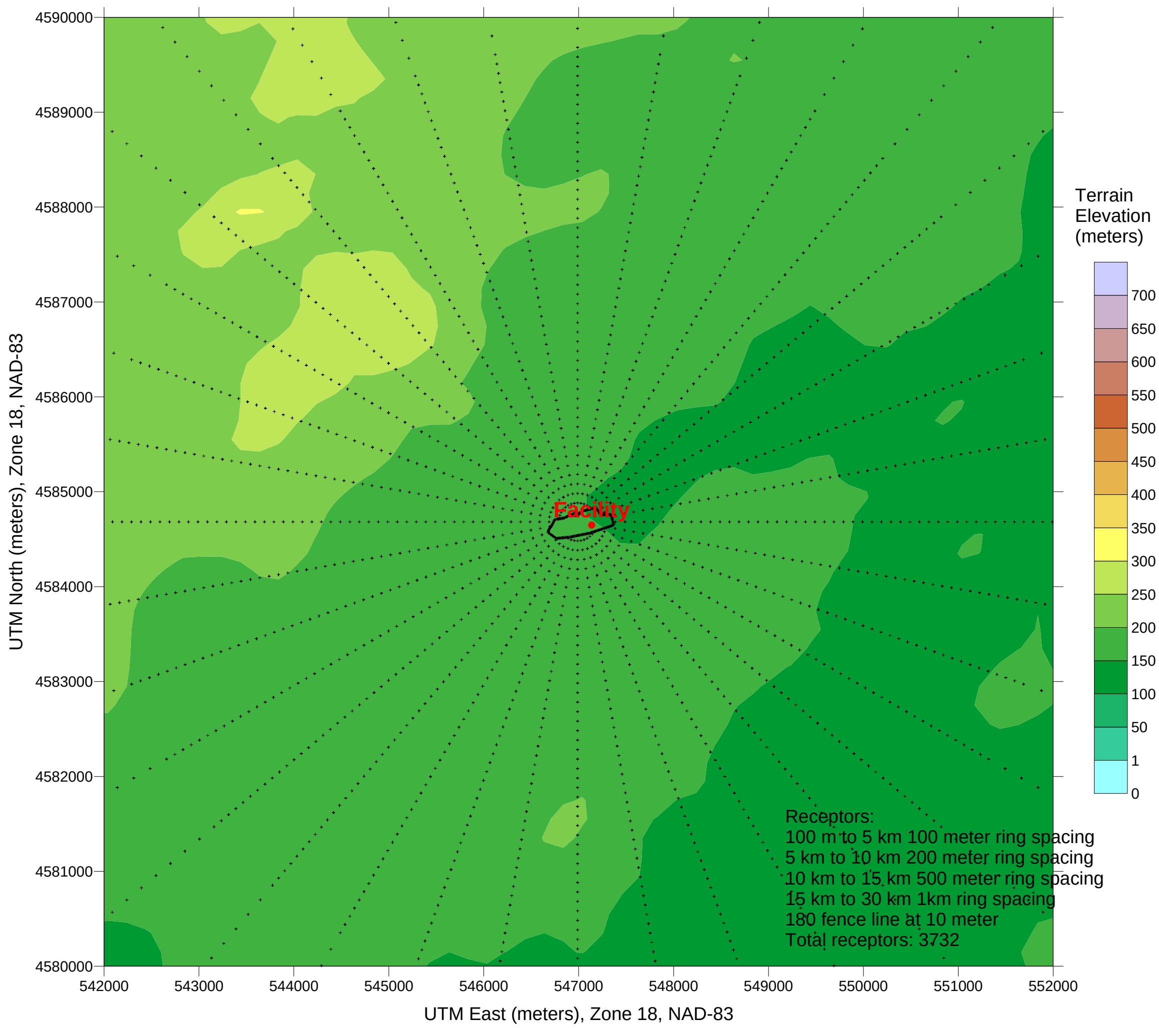


Figure 3-2: Receptors Out to 5,000 Meters

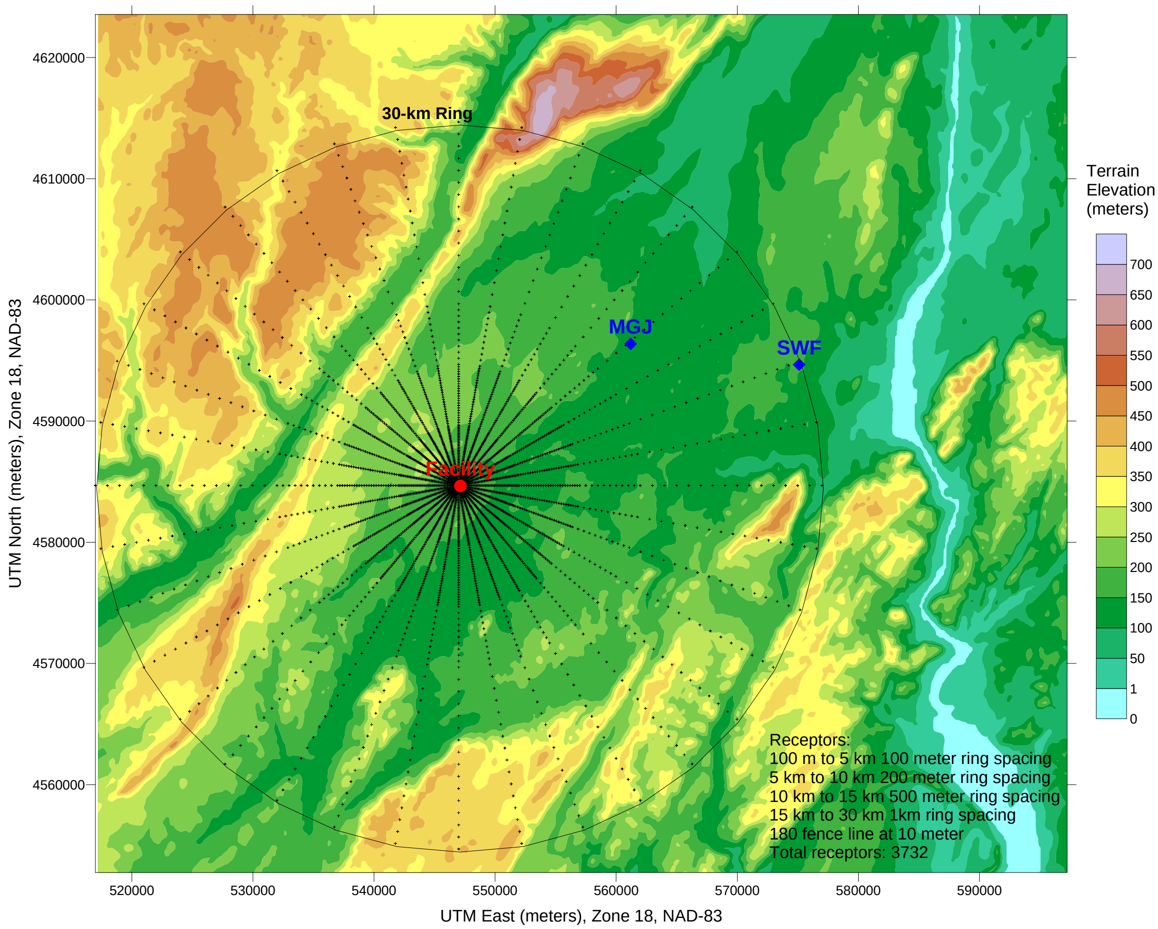


Figure 3-3: Entire Receptor Grid

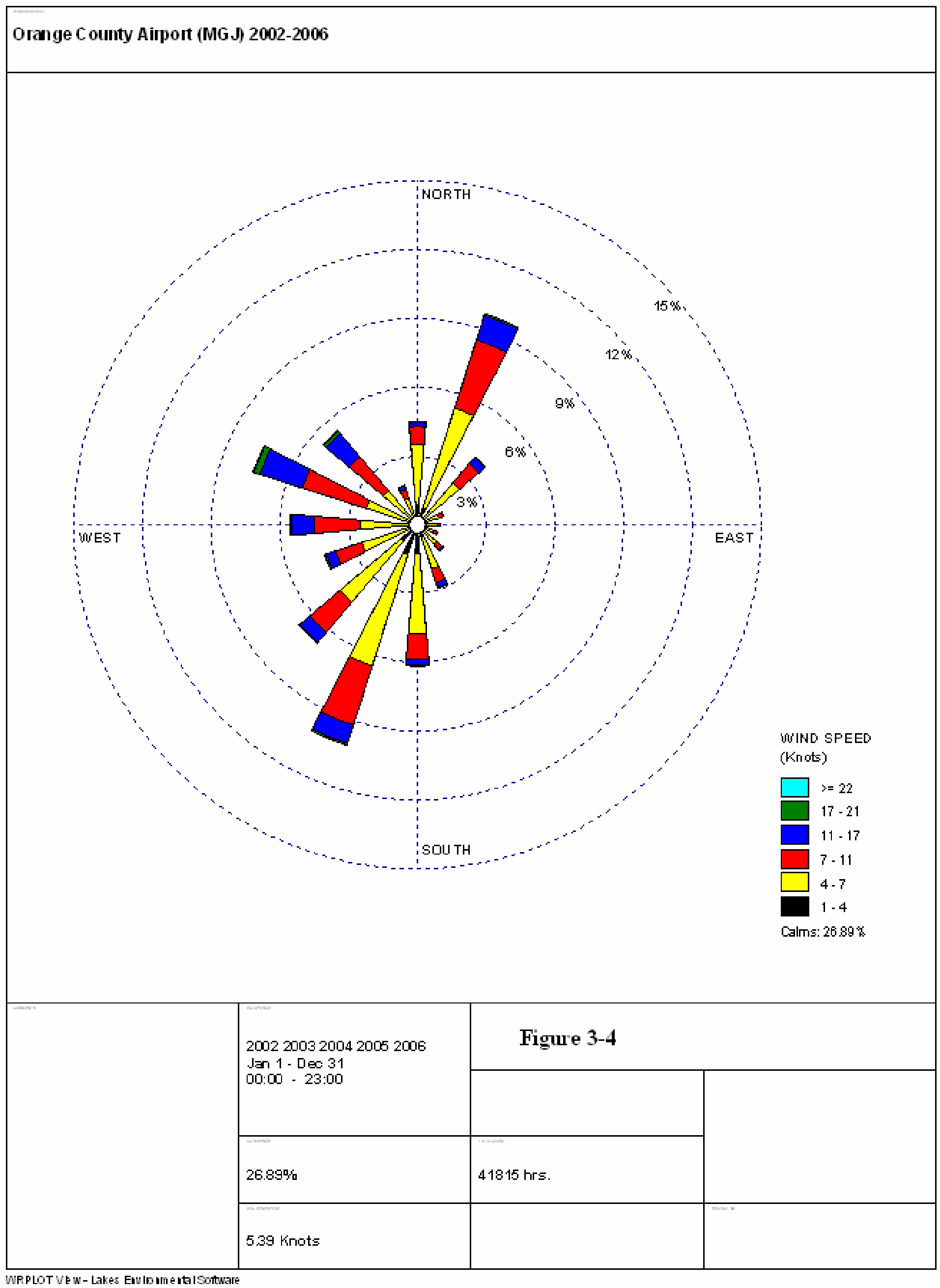


Figure 3-4: Wind Rose for Orange County Airport

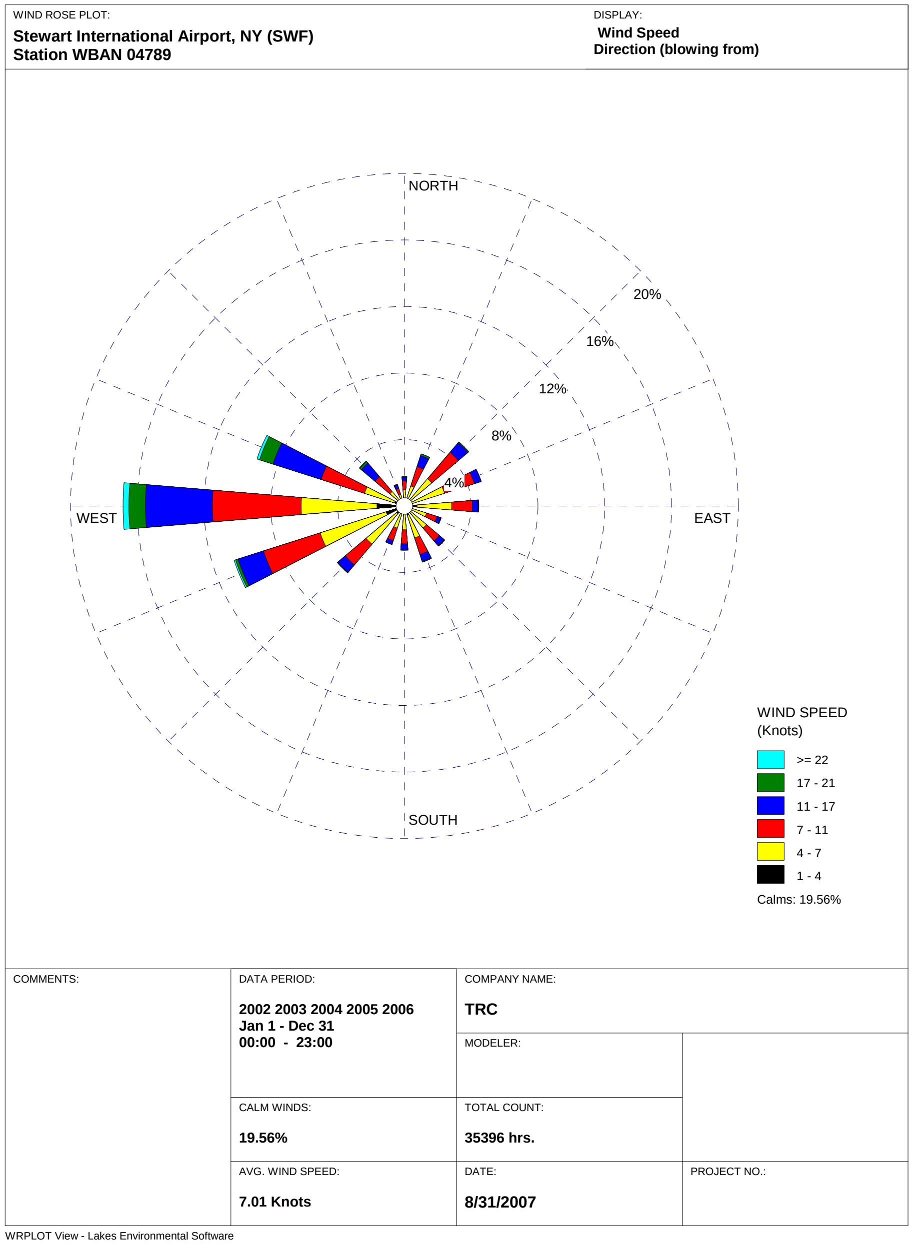
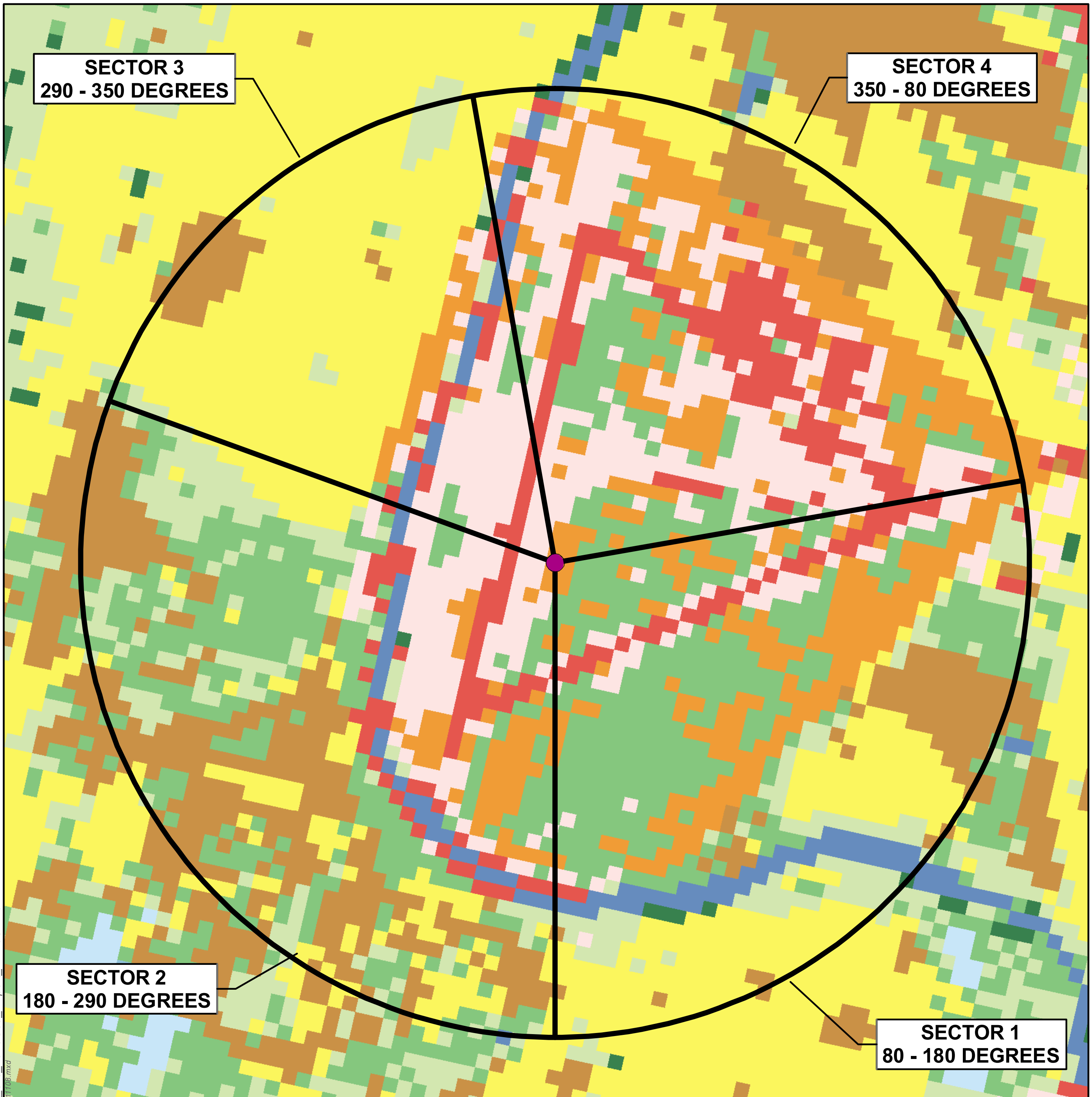


Figure 3-5: Wind rose for Stewart International Airport (SWF)



Centerpoint 41.509 LAT, -74.266 LONG

1-Kilometer Buffer

Land Use, 1992

- Open Water
- Low Intensity Residential
- High Intensity Residential
- Commercial/Industrial/Transportation
- Quarries/Strip Mines, Gravel Pits
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Pasture/Hay
- Row Crops
- Urban/Recreational Grasses
- Woody Wetlands
- Emergent Herbaceous Wetlands

0 100 200 400 600 Meters

N

Source Data:
USGS National Land Cover Data Set, 1992

CPV VALLEY ENERGY CENTER
WAWAYANDA, NEW YORK

LAND USE 1992

TRC
Wannalancit Mills
650 Suffolk Street
Lowell, MA 01854
978-970-5600

FIGURE 3-6

OCTOBER, 2008

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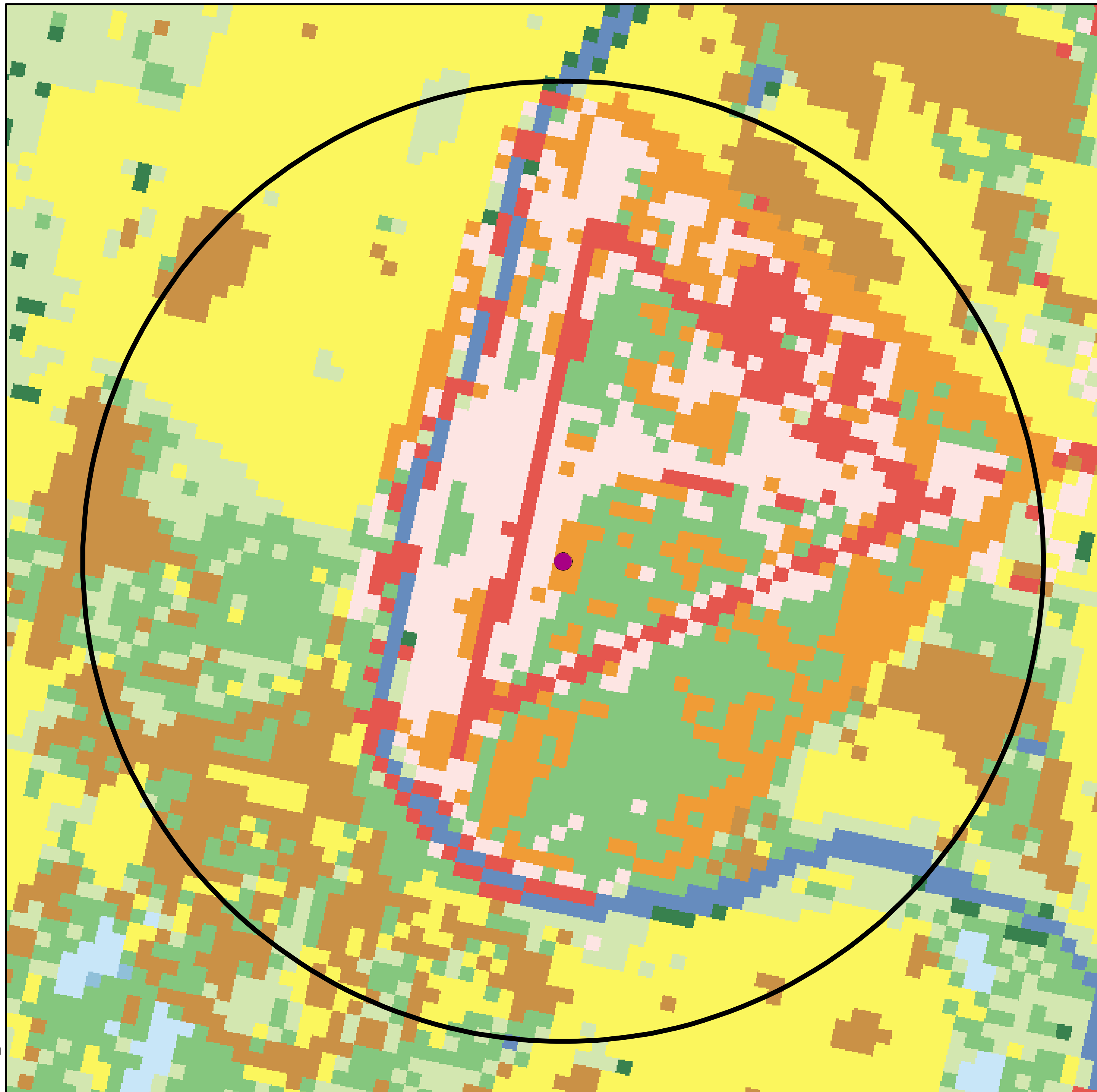
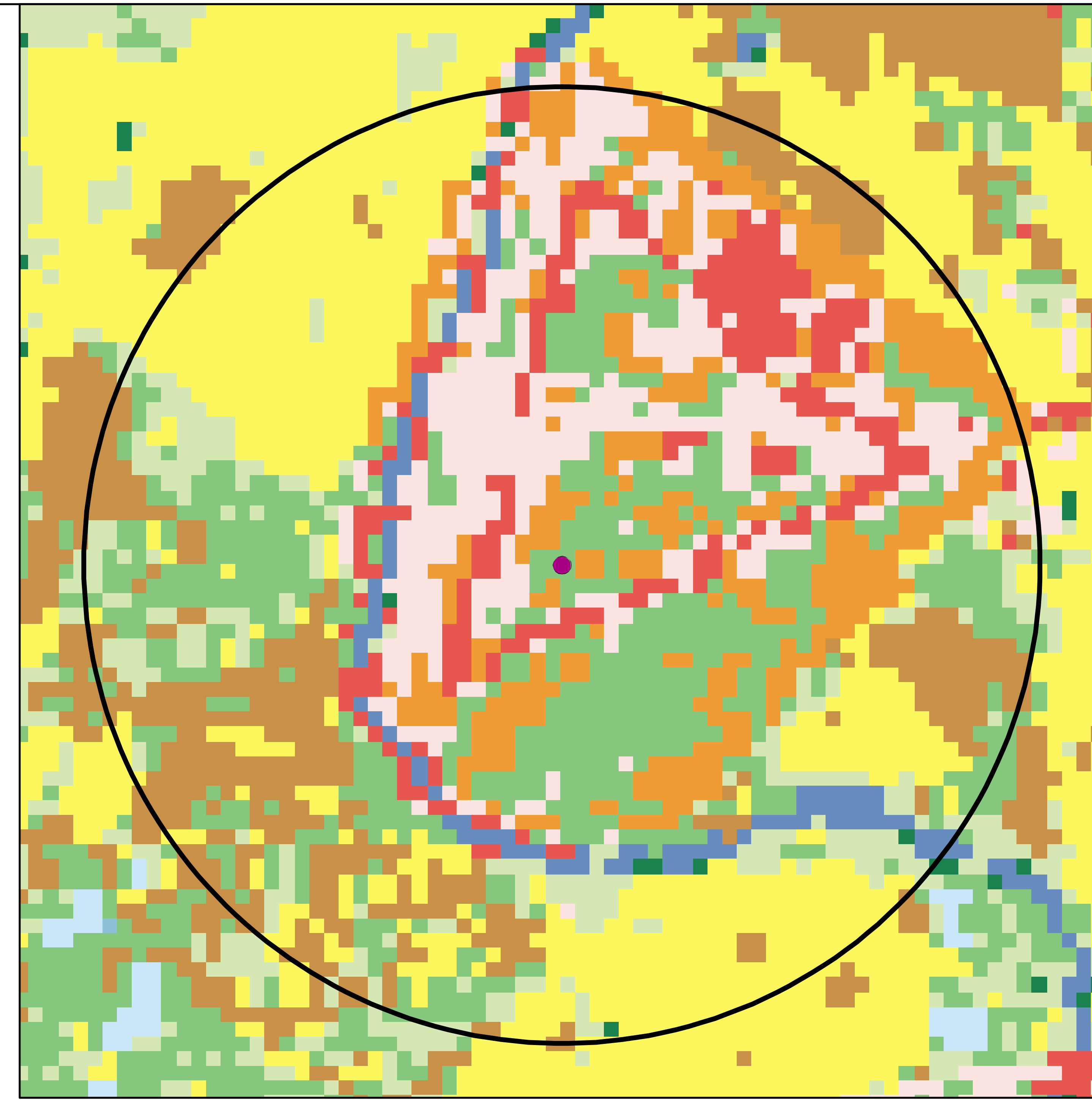


- 1-Kilometer Buffer

Source: USGS National Land Cover Data Set, 1992

Land Use, 1992

- Open Water
- Low Intensity Residential
- High Intensity Residential
- Commercial/Industrial/Transportation
- Quarries/Strip Mines, Gravel Pits
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Pasture/Hay
- Row Crops
- Urban/Recreational Grasses
- Woody Wetlands
- Emergent Herbaceous Wetlands



- 1-Kilometer Buffer

Source: New York State Land Cover Data Set, 1997

Land Use, 1997

- Open Water
- Low Intensity Residential
- High Intensity Residential
- Commercial/Industrial/Transportation
- Quarries/Strip Mines, Gravel Pits
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Pasture/Hay
- Row Crops
- Urban/Recreational Grasses
- Woody Wetlands
- Emergent Herbaceous Wetlands

0 500 1,000 2,000 3,000 Feet

0 250 500 1,000 Meters

N

Updated Centerpoint 41.509 LAT, -74.266 LONG

Figure 3-7

LAND USE
1992 AND 1997

TRC
Wannalancit Mills
650 Suffolk Street
Lowell, MA 01854
978-970-5600

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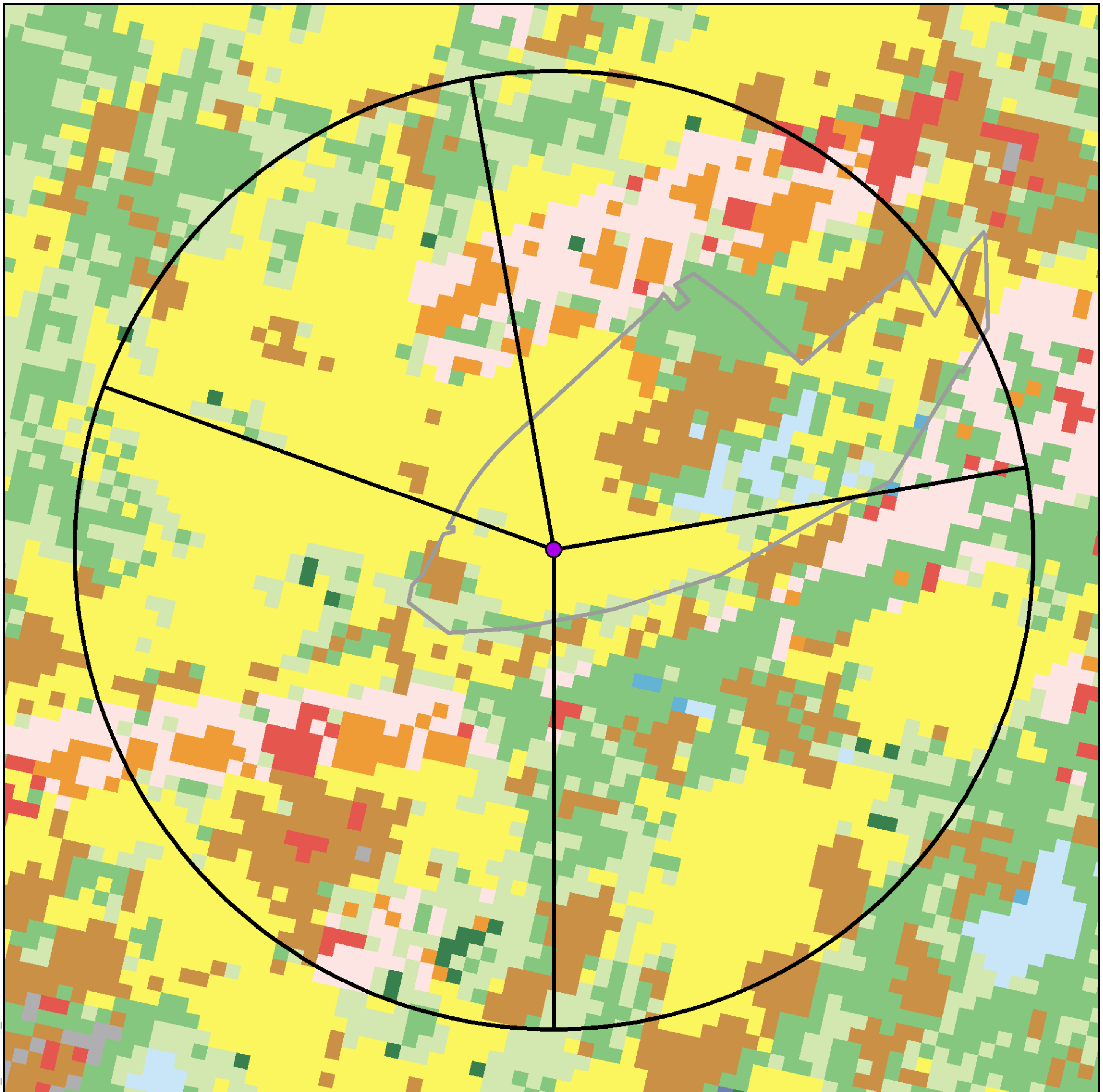

Centerpoint LAT 41.41224, LONG -74.43781

1 Kilometer Radius

Site Boundary

USGS Land Use 1992

- Open Water
- Low Intensity Residential
- High Intensity Residential
- Commercial/Industrial/Transportation
- Quarries/Strip Mines, Gravel Pits
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Pasture/Hay
- Row Crops
- Urban/Recreational Grasses
- Woody Wetlands
- Emergent Herbaceous Wetlands

0 100 200 400 600 Meters

Source Data:
USGS National Land Cover Data Set, 1992

N

CPV VALLEY ENERGY CENTER
WAWAYANDA, NEW YORK

LAND USE 1992

TRC
Wannalancit Mills
650 Suffolk Street
Lowell, MA 01854
978-970-5600

OCTOBER, 2008

FIGURE 3-8

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APPENDIX A

Representative BPIPPRM Input and Output Files

```
'CPV-Valley, NY - UTM Zone 18, NAD83'
'P'
'METERS' 1.0
'UTMY' 0.00
14
'BLDG13'   1          141.43
4         35.05
546871.565   4584665.703
546961.066   4584689.187
546981.796   4584610.473
546892.258   4584586.988
'BLDG18'   1          141.43
4         3.25
547072.783   4584649.359
547102.616   4584656.931
547105.642   4584644.740
547075.809   4584637.181
'BLDG21'   1          141.43
4         4.11
546811.750   4584666.967
546814.838   4584672.904
546817.688   4584671.479
546814.600   4584665.541
'BLDG24'   1          141.43
4         34.44
546978.634   4584712.754
547068.384   4584736.262
547088.692   4584658.847
546998.916   4584635.334
'BLDG28'   1          142.65
4         9.75
546846.329   4584611.721
546864.021   4584616.366
546873.597   4584579.821
546855.918   4584575.189
'BLDG32'   1          141.43
4         31.09
546998.943   4584635.313
547063.782   4584652.318
547080.138   4584589.914
547015.295   4584572.907
'BLDG38'   1          141.43
4         7.01
547115.836   4584654.677
547127.597   4584657.764
547129.386   4584650.989
547117.600   4584647.889
'BLDG43'   1          141.43
4         7.16
546863.584   4584573.280
546874.390   4584576.012
546876.884   4584567.224
546865.721   4584564.493
'BLDG47N'   1          141.43
4         28.35
547069.572   4584732.151
547086.548   4584736.638
547089.690   4584724.581
547072.635   4584720.185
'BLDG47S'   1          141.43
4         28.35
547079.586   4584693.751
547096.629   4584698.263
```

```
547099.703   4584686.260
547082.679   4584681.843
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18         14.17
547157.659   4584754.602
547157.108   4584757.730
547155.520   4584760.480
547153.087   4584762.521
547150.103   4584763.607
547146.927   4584763.607
547143.943   4584762.521
547141.510   4584760.480
547139.923   4584757.730
547139.371   4584754.602
547139.923   4584751.475
547141.510   4584748.724
547143.943   4584746.683
547146.927   4584745.597
547150.103   4584745.597
547153.087   4584746.683
547155.520   4584748.724
547157.108   4584751.475
'TANK19'   1          141.43
18         7.77
546810.550   4584670.951
546809.778   4584675.329
546807.555   4584679.179
546804.149   4584682.037
546799.971   4584683.558
546795.525   4584683.558
546791.347   4584682.037
546787.941   4584679.179
546785.719   4584675.329
546784.946   4584670.951
546785.719   4584666.572
546787.941   4584662.722
546791.347   4584659.864
546795.525   4584658.344
546799.971   4584658.344
546804.149   4584659.864
546807.555   4584662.722
546809.778   4584666.572
'TANK20'   1          141.43
18         6.096
546855.254   4584639.229
546854.703   4584642.356
546853.115   4584645.107
546850.682   4584647.148
546847.698   4584648.234
546844.522   4584648.234
546841.538   4584647.148
546839.105   4584645.107
546837.517   4584642.356
546836.966   4584639.229
546837.517   4584636.102
546839.105   4584633.351
546841.538   4584631.310
546844.522   4584630.224
546847.698   4584630.224
546850.682   4584631.310
546853.115   4584633.351
546854.703   4584636.102
'TANK23'   1          141.43
```

```
18          5.18
547130.588   4584766.502
547130.487   4584767.076
547130.196   4584767.580
547129.750   4584767.954
547129.203   4584768.153
547128.620   4584768.153
547128.073   4584767.954
547127.627   4584767.580
547127.336   4584767.076
547127.235   4584766.502
547127.336   4584765.929
547127.627   4584765.425
547128.073   4584765.051
547128.620   4584764.852
547129.203   4584764.852
547129.750   4584765.051
547130.196   4584765.425
547130.487   4584765.929
6
'CTSN    '   141.43   83.82   546980.477   4584692.872
'CTSS    '   141.43   83.82   546990.525   4584654.552
'AUXB    '   141.43   83.82   546990.525   4584654.552
'HEAT    '   141.43   38.10   546958.846   4584580.546
'DGEN    '   141.43   15.24   547129.875   4584651.454
'PUMP    '   142.65   15.24   546815.015   4584669.435
```

CPV-Valley, NY - UTM Zone 18, NAD83

BPIP (Dated: 04274)

DATE : 10/10/2008
TIME : 17:44:35
CPV-Valley, NY - UTM Zone 18, NAD83

============================
BPIP PROCESSING INFORMATION:
============================

The P flag has been set for preparing downwash related data for a model run utilizing the PRIME algorithm.

Inputs entered in METERS will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

Plant north is set to 0.00 degrees with respect to True North.

CPV-Valley, NY - UTM Zone 18, NAD83

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
CTSN	83.82	0.00	87.62	87.62
CTSS	83.82	0.00	87.62	87.62
AUXB	83.82	0.00	87.62	87.62
HEAT	38.10	0.00	87.62	87.62
DGEN	15.24	0.00	87.62	87.62
PUMP	15.24	1.22	86.40	86.40

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.
** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 04274)

DATE : 10/10/2008

TIME : 17:44:35

CPV-Valley, NY - UTM Zone 18, NAD83

BPIP output is in meters

```
SO BUILDHGT CTSN        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSN        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSN        35.05   35.05   34.44   34.44   35.05   35.05
SO BUILDHGT CTSN        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSN        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSN        35.05   35.05   34.44   34.44   35.05   35.05
SO BUILDWID CTSN       118.15  122.47  123.08  119.94  113.16  102.95
SO BUILDWID CTSN        89.60   88.70  102.20  112.59  119.57  122.91
SO BUILDWID CTSN       122.52  118.40  110.63   99.80   98.97  110.23
SO BUILDWID CTSN       118.15  122.47  123.08  119.94  113.16  102.95
SO BUILDWID CTSN        89.60   88.70  102.20  112.59  119.57  122.91
SO BUILDWID CTSN       122.52  118.40  110.63   99.80   98.97  110.23
SO BUILDLEN CTSN       112.59  119.57  122.91  122.52  118.40  110.69
SO BUILDLEN CTSN        99.61   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN CTSN       119.94  113.16  101.71   88.30   88.70  102.20
SO BUILDLEN CTSN       112.59  119.57  122.91  122.52  118.40  110.69
SO BUILDLEN CTSN        99.61   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN CTSN       119.94  113.16  101.71   88.30   88.70  102.20
SO XBADJ    CTSN      -119.59 -129.67 -135.81 -137.82 -135.64 -129.34
SO XBADJ    CTSN      -119.11 -111.98 -108.91 -102.54  -93.05  -80.74
SO XBADJ    CTSN       -65.97  -49.19  -18.14  -19.31    0.26    3.69
SO XBADJ    CTSN         7.00   10.10   12.90   15.30   17.24   18.65
SO XBADJ    CTSN        19.50   13.01   -1.32  -15.61  -29.42  -42.34
SO XBADJ    CTSN       -53.98  -63.97  -83.57  -68.98  -88.96 -105.88
SO YBADJ    CTSN        43.47   31.81   19.20    6.00   -7.39  -20.55
SO YBADJ    CTSN       -33.08  -44.61  -54.78  -63.30  -69.89  -74.35
SO YBADJ    CTSN       -76.56  -76.44   42.51   47.55  -62.49  -53.80
SO YBADJ    CTSN       -43.47  -31.81  -19.20   -6.00    7.39   20.55
SO YBADJ    CTSN        33.08   44.61   54.78   63.30   69.89   74.35
SO YBADJ    CTSN        76.56   76.44  -42.51  -47.55   62.49   53.80

SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT CTSS        35.05   35.05   35.05   35.05   35.05   35.05
SO BUILDWID CTSS       118.15  122.47  123.08  119.94  113.16  102.95
SO BUILDWID CTSS        89.60   88.70  102.20  112.59  119.57  122.91
SO BUILDWID CTSS       122.52  118.40  110.69   99.61   98.97  110.23
SO BUILDWID CTSS       118.15  122.47  123.08  119.94  113.16  102.95
SO BUILDWID CTSS        89.60   88.70  102.20  112.59  119.57  122.91
SO BUILDWID CTSS       122.52  118.40  110.69   99.61   98.97  110.23
SO BUILDLEN CTSS       112.59  119.57  122.91  122.52  118.40  110.69
SO BUILDLEN CTSS        99.61   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN CTSS       119.94  113.16  102.95   89.60   88.70  102.20
SO BUILDLEN CTSS       112.59  119.57  122.91  122.52  118.40  110.69
SO BUILDLEN CTSS        99.61   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN CTSS       119.94  113.16  102.95   89.60   88.70  102.20
SO XBADJ    CTSS       -83.60  -97.10 -107.65 -114.92 -118.71 -118.88
SO XBADJ    CTSS      -115.45 -115.22 -118.96 -119.09 -115.60 -108.60
SO XBADJ    CTSS       -98.30  -85.01  -69.14  -51.17  -39.22  -34.63
SO XBADJ    CTSS       -28.99  -22.47  -15.27   -7.60    0.30    8.19
SO XBADJ    CTSS        15.84   16.25    8.73    0.94   -6.87  -14.48
```

SO XBADJ	CTSS	-21.65	-28.16	-33.81	-38.44	-49.47	-67.56
SO YBADJ	CTSS	60.02	54.36	47.06	38.32	28.43	17.66
SO YBADJ	CTSS	6.36	-5.12	-16.46	-27.30	-37.31	-46.19
SO YBADJ	CTSS	-53.66	-59.51	-63.54	-65.64	-65.73	-63.84
SO YBADJ	CTSS	-60.02	-54.36	-47.06	-38.32	-28.43	-17.66
SO YBADJ	CTSS	-6.36	5.12	16.46	27.30	37.31	46.19
SO YBADJ	CTSS	53.66	59.51	63.54	65.64	65.73	63.84

SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	AUXB	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDWID	AUXB	118.15	122.47	123.08	119.94	113.16	102.95
SO BUILDWID	AUXB	89.60	88.70	102.20	112.59	119.57	122.91
SO BUILDWID	AUXB	122.52	118.40	110.69	99.61	98.97	110.23
SO BUILDWID	AUXB	118.15	122.47	123.08	119.94	113.16	102.95
SO BUILDWID	AUXB	89.60	88.70	102.20	112.59	119.57	122.91
SO BUILDWID	AUXB	122.52	118.40	110.69	99.61	98.97	110.23
SO BUILDLEN	AUXB	112.59	119.57	122.91	122.52	118.40	110.69
SO BUILDLEN	AUXB	99.61	98.97	110.23	118.15	122.47	123.08
SO BUILDLEN	AUXB	119.94	113.16	102.95	89.60	88.70	102.20
SO BUILDLEN	AUXB	112.59	119.57	122.91	122.52	118.40	110.69
SO BUILDLEN	AUXB	99.61	98.97	110.23	118.15	122.47	123.08
SO BUILDLEN	AUXB	119.94	113.16	102.95	89.60	88.70	102.20
SO XBADJ	AUXB	-83.60	-97.10	-107.65	-114.92	-118.71	-118.88
SO XBADJ	AUXB	-115.45	-115.22	-118.96	-119.09	-115.60	-108.60
SO XBADJ	AUXB	-98.30	-85.01	-69.14	-51.17	-39.22	-34.63
SO XBADJ	AUXB	-28.99	-22.47	-15.27	-7.60	0.30	8.19
SO XBADJ	AUXB	15.84	16.25	8.73	0.94	-6.87	-14.48
SO XBADJ	AUXB	-21.65	-28.16	-33.81	-38.44	-49.47	-67.56
SO YBADJ	AUXB	60.02	54.36	47.06	38.32	28.43	17.66
SO YBADJ	AUXB	6.36	-5.12	-16.46	-27.30	-37.31	-46.19
SO YBADJ	AUXB	-53.66	-59.51	-63.54	-65.64	-65.73	-63.84
SO YBADJ	AUXB	-60.02	-54.36	-47.06	-38.32	-28.43	-17.66
SO YBADJ	AUXB	-6.36	5.12	16.46	27.30	37.31	46.19
SO YBADJ	AUXB	53.66	59.51	63.54	65.64	65.73	63.84

SO BUILDHGT	HEAT	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	HEAT	31.09	31.09	35.05	35.05	35.05	35.05
SO BUILDHGT	HEAT	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	HEAT	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDHGT	HEAT	31.09	31.09	35.05	35.05	35.05	35.05
SO BUILDHGT	HEAT	35.05	35.05	35.05	35.05	35.05	35.05
SO BUILDWID	HEAT	118.15	122.47	123.08	119.94	113.16	102.95
SO BUILDWID	HEAT	70.43	69.78	102.20	112.59	119.57	122.91
SO BUILDWID	HEAT	122.52	118.40	110.69	99.61	98.97	110.23
SO BUILDWID	HEAT	118.15	122.47	123.08	119.94	113.16	102.95
SO BUILDWID	HEAT	70.43	69.78	102.20	112.59	119.57	122.91
SO BUILDWID	HEAT	122.52	118.40	110.69	99.61	98.97	110.23
SO BUILDLEN	HEAT	112.59	119.57	122.91	122.52	118.40	110.69
SO BUILDLEN	HEAT	72.72	72.08	110.23	118.15	122.47	123.08
SO BUILDLEN	HEAT	119.94	113.16	102.95	89.60	88.70	102.20
SO BUILDLEN	HEAT	112.59	119.57	122.91	122.52	118.40	110.69
SO BUILDLEN	HEAT	72.72	72.08	110.23	118.15	122.47	123.08
SO BUILDLEN	HEAT	119.94	113.16	102.95	89.60	88.70	102.20
SO XBADJ	HEAT	-5.22	-16.72	-27.72	-37.87	-46.87	-54.45
SO XBADJ	HEAT	50.43	49.00	-87.28	-100.74	-111.14	-118.17
SO XBADJ	HEAT	-121.60	-121.34	-117.39	-109.87	-106.61	-108.64
SO XBADJ	HEAT	-107.38	-102.85	-95.20	-84.65	-71.53	-56.24

```
SO XBADJ     HEAT     -123.16 -121.08  -22.95  -17.40  -11.33   -4.91
SO XBADJ     HEAT        1.66    8.17   14.44   20.27   17.91    6.44
SO YBADJ     HEAT       41.67   49.91   56.63   61.63   64.76   65.92
SO YBADJ     HEAT        2.53   17.57   57.54   51.08   43.06   33.74
SO YBADJ     HEAT       23.39   12.33    0.90  -10.56  -21.68  -32.17
SO YBADJ     HEAT      -41.67  -49.91  -56.63  -61.63  -64.76  -65.92
SO YBADJ     HEAT       -2.53  -17.57  -57.54  -51.08  -43.06  -33.74
SO YBADJ     HEAT      -23.39  -12.33   -0.90   10.56   21.68   32.17


SO BUILDHGT DGEN         7.01    7.01   31.09   31.09   31.09   31.09
SO BUILDHGT DGEN        35.05   35.05   35.05   35.05   34.44   34.44
SO BUILDHGT DGEN        34.44   34.44   34.44   28.35    7.01    7.01
SO BUILDHGT DGEN         7.01    7.01   31.09   31.09   31.09   31.09
SO BUILDHGT DGEN        34.44   34.44   34.44   34.44   34.44   34.44
SO BUILDHGT DGEN        34.44   34.44   34.44   28.35    7.01    7.01
SO BUILDWID DGEN        13.98   13.99   93.02   91.38   86.97   79.91
SO BUILDWID DGEN        89.60   88.70  102.20  112.59  118.60  122.14
SO BUILDWID DGEN       121.97  118.09  110.63  117.00   12.70   13.55
SO BUILDWID DGEN        13.98   13.99   93.02   91.38   86.97   79.91
SO BUILDWID DGEN        97.19   87.33  100.93  111.46  118.60  122.14
SO BUILDWID DGEN       121.97  118.09  110.63  117.00   12.70   13.55
SO BUILDLEN DGEN        11.46   12.70   93.02   92.00   88.19   81.70
SO BUILDLEN DGEN        99.61   98.97  110.23  118.15  121.86  122.27
SO BUILDLEN DGEN       118.96  112.04  101.71   88.30    7.99    9.88
SO BUILDLEN DGEN        11.46   12.70   93.02   92.00   88.19   81.70
SO BUILDLEN DGEN       216.56   99.03  110.06  117.75  121.86  122.27
SO BUILDLEN DGEN       118.96  112.04  101.71   88.30    7.99    9.88
SO XBADJ    DGEN        -5.64   -7.55 -125.31 -133.82 -138.26 -138.50
SO XBADJ    DGEN      -245.34 -251.91 -258.31 -256.86 -163.09 -161.63
SO XBADJ    DGEN      -155.26 -144.17 -128.71 -109.33   -6.61   -6.31
SO XBADJ    DGEN        -5.82   -5.15   32.30   41.82   50.07   56.81
SO XBADJ    DGEN        28.78   39.27   41.18   41.84   41.23   39.36
SO XBADJ    DGEN        36.30   32.14   26.99   21.03   -1.38   -3.57
SO YBADJ    DGEN         7.39    7.30   58.81   44.23   28.31   11.53
SO YBADJ    DGEN        56.94   22.12  -13.37  -48.45   -0.64  -18.37
SO YBADJ    DGEN       -35.54  -51.64  -66.16  -70.08   -6.91   -7.26
SO YBADJ    DGEN        -7.39   -7.30  -58.81  -44.23  -28.31  -11.53
SO YBADJ    DGEN       -60.73  -50.53  -34.34  -17.11    0.64   18.37
SO YBADJ    DGEN        35.54   51.64   66.16   70.08    6.91    7.26


SO BUILDHGT PUMP         4.11    4.11    7.77    7.77    7.77    7.77
SO BUILDHGT PUMP        34.44   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT PUMP        35.05   35.05    7.77    7.77    4.11    4.11
SO BUILDHGT PUMP         4.11    4.11    7.77    7.77    7.77    7.77
SO BUILDHGT PUMP        34.44   35.05   35.05   35.05   35.05   35.05
SO BUILDHGT PUMP        35.05   35.05    7.77    7.77    4.11    4.11
SO BUILDWID PUMP         5.06   31.36   25.21   25.60   25.21   25.60
SO BUILDWID PUMP        97.19   88.70  102.20  112.59  119.57  122.91
SO BUILDWID PUMP       122.52  118.40   25.21   25.60    6.63    5.94
SO BUILDWID PUMP         5.06   31.36   25.21   25.60   25.21   25.60
SO BUILDWID PUMP        88.30   88.70  102.20  112.59  119.57  122.91
SO BUILDWID PUMP       122.52  118.40   25.21   25.60    6.63    5.94
SO BUILDLEN PUMP         7.29   25.21   25.60   25.21   25.60   25.21
SO BUILDLEN PUMP       216.56   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN PUMP       119.94  113.16   25.60   25.21    7.21    7.36
SO BUILDLEN PUMP         7.29   25.21   25.60   25.21   25.60   25.21
SO BUILDLEN PUMP        99.80   98.97  110.23  118.15  122.47  123.08
SO BUILDLEN PUMP       119.94  113.16   25.60   25.21    7.21    7.36
SO XBADJ    PUMP        -3.91  -17.09  -20.12  -22.55  -25.05  -26.80
SO XBADJ    PUMP        44.39   55.04   56.55   56.34   54.42   50.84
SO XBADJ    PUMP        45.72   39.21  -22.75  -19.94   -3.45   -3.47
```

SO XBADJ	PUMP	-3.39	-8.13	-5.48	-2.67	-0.55	1.59
SO XBADJ	PUMP	-260.95	-154.01	-166.78	-174.49	-176.89	-173.92
SO XBADJ	PUMP	-165.66	-152.37	-2.86	-5.28	-3.76	-3.89
SO YBADJ	PUMP	0.25	13.87	15.71	14.20	12.26	9.95
SO YBADJ	PUMP	-63.85	-50.26	-31.35	-11.48	8.73	28.68
SO YBADJ	PUMP	47.75	65.38	-14.20	-15.71	-0.33	-0.30
SO YBADJ	PUMP	-0.25	-13.87	-15.71	-14.20	-12.26	-9.95
SO YBADJ	PUMP	59.40	50.26	31.35	11.48	-8.73	-28.68
SO YBADJ	PUMP	-47.75	-65.38	14.20	15.71	0.33	0.30

APPENDIX B

Extracts from AERMAP Input Files

```
CO STARTING
   TITLEONE  CPV-Valley, NY
CO TERRHGTS  EXTRACT

   DATATYPE  DEM7
   DATAFILE  dem\1647580.dem
   DATAFILE  dem\1660177.dem
   DATAFILE  dem\1660178.dem
   DATAFILE  dem\1660179.dem
   DATAFILE  dem\1660180.dem
   DATAFILE  dem\1660181.dem
   DATAFILE  dem\1660186.dem
   DATAFILE  dem\1660187.dem
   DATAFILE  dem\1660188.dem
   DATAFILE  dem\1660189.dem
   DATAFILE  dem\1660190.dem
   DATAFILE  dem\1660195.dem
   DATAFILE  dem\1660196.dem
   DATAFILE  dem\1660197.dem
   DATAFILE  dem\1660198.dem
   DATAFILE  dem\1660199.dem
   DATAFILE  dem\1660204.dem
   DATAFILE  dem\1660205.dem
   DATAFILE  dem\1660206.dem
   DATAFILE  dem\1660316.dem
   DATAFILE  dem\1660317.dem
   DATAFILE  dem\1660318.dem
   DATAFILE  dem\1660319.dem
   DATAFILE  dem\1660320.dem
   DATAFILE  dem\1661369.dem
   DATAFILE  dem\1661370.dem
   DATAFILE  dem\1661373.dem
   DATAFILE  dem\1661374.dem
   DATAFILE  dem\1661376.dem
   DATAFILE  dem\1661377.dem
   DATAFILE  dem\1698832.dem
   DATAFILE  dem\1698838.dem
   DATAFILE  dem\1698839.dem
   DATAFILE  dem\1705860.dem
   DATAFILE  dem\3520625.dem
   DATAFILE  dem\1660321.dem
   DATAFILE  dem\1660182.dem
   DATAFILE  dem\1660191.dem
   DATAFILE  dem\1660200.dem
   DATAFILE  dem\1660207.dem

   DOMAINXY  527135.0 4564645.0 18 567140.0 4604650.0 18
**  lowr left easting  Northing Zn  easting  northing Zn of upper right
   ANCHORXY  527135.0 4564645.0    527135.0 4564645.0 18  4
**           X-point Y-point       East'g   North'g   Zn of X, Y point
   RUNORNOT  RUN
CO FINISHED
```

```
CO STARTING
   TITLEONE  CPV-Valley, NY
CO TERRHGTS  EXTRACT

   DATATYPE  DEM7
   DATAFILE  dem\1647580.dem
   DATAFILE  dem\1660177.dem
   DATAFILE  dem\1660178.dem
   DATAFILE  dem\1660179.dem
   DATAFILE  dem\1660180.dem
   DATAFILE  dem\1660181.dem
   DATAFILE  dem\1660186.dem
   DATAFILE  dem\1660187.dem
   DATAFILE  dem\1660188.dem
   DATAFILE  dem\1660189.dem
   DATAFILE  dem\1660190.dem
   DATAFILE  dem\1660195.dem
   DATAFILE  dem\1660196.dem
   DATAFILE  dem\1660197.dem
   DATAFILE  dem\1660198.dem
   DATAFILE  dem\1660199.dem
   DATAFILE  dem\1660204.dem
   DATAFILE  dem\1660205.dem
   DATAFILE  dem\1660206.dem
   DATAFILE  dem\1660316.dem
   DATAFILE  dem\1660317.dem
   DATAFILE  dem\1660318.dem
   DATAFILE  dem\1660319.dem
   DATAFILE  dem\1660320.dem
   DATAFILE  dem\1661369.dem
   DATAFILE  dem\1661370.dem
   DATAFILE  dem\1661373.dem
   DATAFILE  dem\1661374.dem
   DATAFILE  dem\1661376.dem
   DATAFILE  dem\1661377.dem
   DATAFILE  dem\1698832.dem
   DATAFILE  dem\1698838.dem
   DATAFILE  dem\1698839.dem
   DATAFILE  dem\1705860.dem
   DATAFILE  dem\3520625.dem
   DATAFILE  dem\1660321.dem
   DATAFILE  dem\1660182.dem
   DATAFILE  dem\1660191.dem
   DATAFILE  dem\1660200.dem
   DATAFILE  dem\1660207.dem

   DOMAINXY  515000.0 4553000.0 18 585000.0 4615000.0 18
**  lowr left easting  Northing Zn  easting  northing Zn of upper right
   ANCHORXY  515000.0 4553000.0    515000.0 4553000.0 18  4
**           X-point Y-point       East'g   North'g   Zn of X, Y point
   RUNORNOT  RUN
CO FINISHED
```

APPENDIX C

AERSURFACE Input and Output Files

```
new_york_NLCD_erd_070600.tif	**	Land	use	data	file
LU_CPV-Valley.dat	**	Output	file	with	sfc	values	for
AERMET	Stage	3
LATLON	**	Coordinate	type	(UTM	LATLON)
41.509	**	Latitude
-74.266	**	Longitude
NAD83	**	Datum
1	**	Study	radius	for	surface	roughness	(km)
Y	**	Vary	by	sector?	(Y/N)
4	**	Number	of	sectors
80	**	Start	of	sector	1
180	**	Start	of	sector	2
290	**	Start	of	sector	3
350	**	Start	of	sector	4
M	**	Temporal	resolution	(A=ANNUAL	M=MONTHLY
S=SEASONAL)
N	**	Continuous	snow	cover	at	least	one	month?
(Y/N)
Y	**	Reassign	months	to	seasons?	(Y/N)
12	1	2	3	**	Late	autumn	after	frost	and
harvest	or	winter	with	no	snow
4	5	**	Transitional	spring	(partial	green	coverage
short	annuals)
6	7	8	9	**	Midsummer	with	lush	vegetation
10	11	**	Autumn	with	unharvested	cropland
Y	**	Airport?	(Y/N)
N	**	Arid	region?	(Y/N)
A	**	Surface	Moisture	(A=Average	W=Wet	D=Dry)
```

```
**      Generated       by      AERSURFACE      dated   8009
**      Center  Latitude        (decimal        degrees):       41.509
**      Center  Longitude       (decimal        degrees):       -74.266
**      Datum:  NAD83
**      Study   radius  (km)    for     surface roughness:      1
**      Airport?        Y       Continuous      snow    cover?  N
**      Surface moisture?       Average Arid    region? N
**      Month/Season    assignments?    User-specified
**      Late    autumn  after   frost   and     harvest or      winter  with    no
snow:   12      1       2       3
**      Winter  with    continuous      snow    on      the     ground: 0
**      Transitional    spring  (partial        green   coverage        short
annuals):       4       5
**      Midsummer       with    lush    vegetation:     6       7       8       9
**      Autumn  with    unharvested     cropland:       10      11
**
FREQ_SECT       MONTHLY 4
SECTOR  1       80      180
SECTOR  2       180     290
SECTOR  3       290     350
SECTOR  4       350     80
**      Month   Sect    Alb     Bo      Zo
SITE_CHAR       1       1       0.17    0.79    0.115
SITE_CHAR       1       2       0.17    0.79    0.123
SITE_CHAR       1       3       0.17    0.79    0.07
SITE_CHAR       1       4       0.17    0.79    0.098
SITE_CHAR       2       1       0.17    0.79    0.115
SITE_CHAR       2       2       0.17    0.79    0.123
SITE_CHAR       2       3       0.17    0.79    0.07
SITE_CHAR       2       4       0.17    0.79    0.098
SITE_CHAR       3       1       0.17    0.79    0.115
SITE_CHAR       3       2       0.17    0.79    0.123
SITE_CHAR       3       3       0.17    0.79    0.07
SITE_CHAR       3       4       0.17    0.79    0.098
SITE_CHAR       4       1       0.15    0.48    0.167
SITE_CHAR       4       2       0.15    0.48    0.162
SITE_CHAR       4       3       0.15    0.48    0.089
SITE_CHAR       4       4       0.15    0.48    0.127
SITE_CHAR       5       1       0.15    0.48    0.167
SITE_CHAR       5       2       0.15    0.48    0.162
SITE_CHAR       5       3       0.15    0.48    0.089
SITE_CHAR       5       4       0.15    0.48    0.127
SITE_CHAR       6       1       0.17    0.39    0.265
SITE_CHAR       6       2       0.17    0.39    0.276
SITE_CHAR       6       3       0.17    0.39    0.197
SITE_CHAR       6       4       0.17    0.39    0.17
SITE_CHAR       7       1       0.17    0.39    0.265
SITE_CHAR       7       2       0.17    0.39    0.276
SITE_CHAR       7       3       0.17    0.39    0.197
SITE_CHAR       7       4       0.17    0.39    0.17
SITE_CHAR       8       1       0.17    0.39    0.265
SITE_CHAR       8       2       0.17    0.39    0.276
SITE_CHAR       8       3       0.17    0.39    0.197
SITE_CHAR       8       4       0.17    0.39    0.17
SITE_CHAR       9       1       0.17    0.39    0.265
SITE_CHAR       9       2       0.17    0.39    0.276
SITE_CHAR       9       3       0.17    0.39    0.197
SITE_CHAR       9       4       0.17    0.39    0.17
SITE_CHAR       10      1       0.17    0.78    0.25
SITE_CHAR       10      2       0.17    0.78    0.268
SITE_CHAR       10      3       0.17    0.78    0.194
SITE_CHAR       10      4       0.17    0.78    0.156
SITE_CHAR       11      1       0.17    0.78    0.25
```

SITE_CHAR	11	2	0.17	0.78	0.268
SITE_CHAR	11	3	0.17	0.78	0.194
SITE_CHAR	11	4	0.17	0.78	0.156
SITE_CHAR	12	1	0.17	0.79	0.115
SITE_CHAR	12	2	0.17	0.79	0.123
SITE_CHAR	12	3	0.17	0.79	0.07
SITE_CHAR	12	4	0.17	0.79	0.098

APPENDIX H

CUMULATIVE PM-10 EMISSION INVENTORY

Multi-source PSD PM_{10} Modeling Inventory Development

A multi-source modeling emissions inventory was compiled to support the multi-source National Ambient Air Quality Standards (NAAQS) analysis and PSD increment analysis for the proposed CPV Valley Energy Center (CPV Valley), Wawayanda, New York. The inventory was based on information available from the New York Department of Conservation (NYSDEC) Central Albany Office and the Region 3 Office, which covers the Catskills, Lower Hudson Valley, and Long Island Sound. The inventory was compiled for particulate matter with an aerodynamic diameter less than 10 micrometers (PM-10).

As a first step in the inventory development, an inventory of all major sources within 60 kilometers (km) of the proposed CPV Valley site was provided by the NYSDEC from its Air Facility System (AFS). For this modeling inventory, TRC conservatively considered a source to be “major” if the facility potential to emit (PTE) exceeded 95 tons per year (tpy) for any pollutant. However, the multi-source modeling analysis only included the PM_{10} emissions from each source, since this is the only pollutant for which the proposed CPV Valley Energy Center was predicted to have significant air quality impacts. After the significant impact area (SIA) was determined for the CPV Valley Energy Center to be 4.6 km, any sources located beyond the SIA plus 50 km (or approximately 55 km) were removed from the inventory.

In addition, any major PM_{10} sources within 60 km of the proposed site location and located in Pennsylvania or New Jersey were requested from the Pennsylvania Department of Environmental Protection (PaDEP) and New Jersey Department of Environmental Protection (NJDEP), respectively. Both agencies indicated that there were no major PM_{10} sources in their respective states located within 60 km of the proposed site.

The data from the AFS system was processed, and any missing data values were identified. TRC then worked with the NYSDEC Region 3 office to fill many of the missing data values, and a permitting file review was conducted by TRC at the Region 3 office in an attempt to fill the remaining missing data. After these attempts to fill in the missing data, some PM-10 emission rates and exhaust characteristics were still not available. Therefore, TRC used any permit limits and/or the United States Environmental Protection Agency’s (U.S. EPA’s) AP-42 emission factors to estimate PM-10 emission rates from each of the source for which data were missing. To estimate missing exhaust characteristics, TRC used data from similar type/sized equipment or engineering estimates to develop these values.

Table 1 presents the PM-10 inventory developed following this process. It should be noted that Table 1 provides all of the PM_{10} emission sources at each facility. However, for inclusion in the AERMOD modeling analysis, TRC consolidated some of the emission sources to minimize the number of separate point sources in the model runs.

In order to simplify the modeling analyses, reduce modeling run time, and add conservatism to the analyses, TRC combined sources to form one to several “representative” emission sources, in accordance with the methodology provided in Section 2.2 of Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised (U.S. EPA, 1992). Using the recommended methodology, a value for M is computed for each emission point at the facility, where:

$M = (h_s V T_s)/Q$

and: M = merged stack parameter which accounts for the relative influence of stack height, plume rise, and emission rate on concentrations

h_s = stack height (m)

$V = (\pi/4) d_s^2 v_s$ = stack gas volumetric flow rate (m^3/s)

d_s = inside stack diameter (m)

v_s = stack gas exit velocity (m/s)

T_s = stack gas exit temperature (K)

Q = pollutant emission rate (g/s)

The emission source that has the lowest calculated value for M was used as a "representative" emission source, with the total of the emissions from all the emission sources assumed to be emitted from one stack having the emission parameters of the "representative" emission source. Sources located at a facility within the SIA (i.e., 4.6 km) due to the proposed CPV Valley Energy Center were not merged.

The merged sources used in the multi-source NAAQS and PSD increment modeling analyses are presented in Table 2. As indicated in Table 2, the short-term (lb/hr) potential PM-10 emission rates were modeled to determine both the 24-hour and annual PM-10 concentrations.

Table 1: PM_{10} Source Inventory (PSD/Large Source Analysis)

DEC	Facility Name	Major Pollutants	Distance from CPV (km)	Emission Unit ID	Emission Point ID	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions (lb/hr)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)	M-Value
3130200017	CHEMPRENE INC	SO_2	39.6	CINSIG	1	585,532	4,593,624	61.57	2.32	3.66	294.3	15.54	0.46	9,407
				CINSIG	2	585,532	4,593,624	61.57	2.32	3.66	294.3	15.54	0.46	9,407
				CINSIG	5	585,532	4,593,724	61.57	3.40	1.83	294.3	16.76	0.53	4,703
				B07A08	7	585,532	4,593,624	61.57	1.20	10.67	422.0	15.54	0.61	135,104
				B07A08	8	585,532	4,593,624	61.57	1.20	0.91	422.0	15.54	0.61	11,580
				C00113	113	585,532	4,593,624	61.57	4.44	4.27	294.3	16.76	0.61	10,975
3134600019	DUTCHESS CO RESOURCE RECOVERY FACILITY	CO, SO_2, HCL, NO_X	49.0	1MBMWC	FLUE1	588,032	4,611,524	20.42	5	60.96	477.6	24.38	1.22	1,315,616
				1MBMWC	FLUE2	588,032	4,611,524	20.42		60.96	477.6	24.38	1.22	1,315,616
3134600035	IBM CORP SOUTH RD FACILITY	NO_X	50.0	C00001	242KM	588,532	4,611,924	27.43	1.90	18.59	294.3	6.10	0.66	47,819
				C00001	242NI	588,532	4,611,924	27.43	0.91	16.76	294.3	6.10	0.46	114,974
				C00001	342BG	588,532	4,611,924	27.43	1.53	14.94	294.3	3.05	0.75	30,475
				C00001	342BL	588,532	4,611,924	27.43	0.13	14.02	294.3	7.92	0.15	36,060
				C00001	342CD	588,532	4,611,924	27.43	0.61	16.15	294.3	5.18	0.41	41,547
				C00001	342CK	588,532	4,611,924	27.43	0.73	16.46	294.3	2.74	0.61	42,331
				C00001	342CP	588,532	4,611,924	27.43	1.65	14.33	294.3	4.57	0.62	28,197
				C00001	342FA	588,532	4,611,924	27.43	0.62	16.76	294.3	3.05	0.53	43,115
				C00001	342KC	588,532	4,611,924	27.43	0.53	5.49	294.3	7.92	0.30	14,110
				C00001	342LB	588,532	4,611,924	27.43	0.28	5.49	294.3	6.10	0.25	14,110
				C00001	342MA	588,532	4,611,924	27.43	4.00	15.85	294.3	6.71	0.91	40,764
				C00001	342MB	588,532	4,611,924	27.43	0.23	15.85	294.3	1.52	0.46	40,764
				C00001	342MC	588,532	4,611,924	27.43	0.27	16.15	294.3	1.83	0.46	41,547
				C00001	342SC	588,532	4,611,924	27.43	0.01	5.49	294.3	1.83	0.10	14,110
				C00001	342TB	588,532	4,611,924	27.13	1.18	15.54	294.3	6.40	0.51	39,980
				C00001	342TL	588,532	4,611,924	27.43	1.13	15.24	294.3	4.27	0.61	39,196
				C00001	342WE	588,532	4,611,924	27.43	1.32	15.24	294.3	7.92	0.48	39,196
				C00001	342WF	588,532	4,611,924	27.43	0.07	16.76	294.3	0.91	0.29	32,655
				C00001	342WG	588,532	4,611,924	27.43	1.94	16.76	294.3	7.32	0.61	43,115
				C00001	342WH	588,532	4,611,924	27.43	4.99	16.76	294.3	7.92	0.94	43,115
				C00001	342WL	588,532	4,611,924	27.43	0.32	17.07	294.3	2.74	0.41	43,899
				C00001	342WM	588,532	4,611,924	27.43	0.79	14.02	294.3	4.27	0.51	36,060
				C00001	343PF	588,532	4,611,924	27.43	0.79	16.15	294.3	6.71	0.41	41,547
				E00001	643AA	588,532	4,611,924	28.96	4.13	9.14	294.3	10.67	0.64	17,841
				E00001	643AB	588,532	4,611,924	30.48	0.54	8.53	294.3	4.57	0.35	16,291
				B00001	D42TA	588,532	4,611,924	27.43	6.18	20.73	294.3	10.36	0.91	53,306
				B00001	D42TG	588,532	4,611,924	27.43	7.45	20.73	294.3	12.50	0.91	53,306
				B00001	442XF	588,532	4,611,924	27.43	0.41	2.44	294.3	1.22	0.61	4,955
				B00001	W42CA	588,532	4,611,924	27.43	2.97	12.19	294.3	3.66	1.07	31,357
				A00001	SR001	588,532	4,611,924	4.57	6.75	23.17	427.6	10.06	1.14	120,204
				A00001	SR002	588,532	4,611,924	4.57	6.75	23.17	487.6	11.28	1.14	153,685
				A00001	SR003	588,532	4,611,924	4.57	6.75	23.17	495.9	10.06	1.14	139,413
				A00001	SR006	588,532	4,611,924	3.66	6.75	15.24	469.3	15.24	0.91	84,158
				A00001	SR007	588,532	4,611,924	3.66	6.75	15.24	505.4	17.07	0.91	101,510
				H00001	W42AK	588,532	4,611,924	29.26	0.16	4.88	294.3	2.44	0.30	12,543
				H00001	W42AM	588,532	4,611,924	29.26	0.12	30.18	294.3	3.96	0.20	77,607
				D00001	W42GD	588,532	4,611,924	27.43	0.16	7.92	294.3	1.83	0.36	20,382
				D00001	W42SL	588,532	4,611,924	6.10	0.39	3.05	294.3	2.13	0.45	6,271
				D00001	W42ST	588,532	4,611,924	6.10	1.65	9.14	294.3	2.13	0.91	18,131
				D00001	W42WG	588,532	4,611,924	17.68	2.58	10.67	294.3	11.58	0.56	27,437
				D00001	W42WH	588,532	4,611,924	17.68	2.65	10.67	294.3	11.89	0.56	27,437
3134600067	VASSAR COLLEGE	SO_2, NO_X	54.5	U00005	BLR01	592,000	4,615,400	45.11	2.30	15.24	505.4	14.94	0.61	115,854

Table 1: PM_{10} Source Inventory (PSD/Large Source Analysis)

DEC	Facility Name	Major Pollutants	Distance from CPV (km)	Emission Unit ID	Emission Point ID	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions (lb/hr)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)	M-Value
				U00005	BLR02	592,000	4,615,400	45.11	2.30	15.24	505.4	14.94	0.61	115,854
				U00002	BLR03	592,000	4,615,600	45.11	2.40	15.24	505.4	6.71	0.91	112,159
				U00002	BLR04	592,000	4,615,600	45.11	2.40	15.24	505.4	6.71	0.91	112,159
				U00001	BLR05	592,000	4,615,600	45.11	3.80	18.29	505.4	6.10	1.22	137,382
				U00004	CHL01	592,000	4,615,600	45.72	0.47	6.10	505.4	8.53	0.51	89,991
3330900101	ORANGE RECYCLING & ETHANOL PROD FAC	SO_2, NO_X	2.0	UGASBR	1	548,115	4,586,340	153.32	27.04	30.48	408.7	12.80	2.64	256,541
				UTOWER	4	548,115	4,586,340	150.27	5.22	11.58	302.6	13.72	3.35	645,315
				UTOWER	5	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	6	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	7	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	8	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	9	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	10	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
				UTOWER	11	548,115	4,586,340	150.27		11.58	302.6	13.72	3.35	645,315
3331100114	PRISMATIC DYEING & FINISHING INC	SO_2	34.7	B00001	36	580,200	4,594,700	30.48	1.90	6.10	533.2	10.36	0.61	41,064
3334800084	METAL CONTAINER CORP	VOC	29.6	U10000	EP030	575,339	4,593,229	149.35	14.77	12.50	294.3	3.96	2.29	32,140
				U10000	EP066	575,339	4,593,229	149.35	0.15	12.80	294.3	0.30	0.75	26,122
				U10000	EP067	575,339	4,593,229	149.35	0.15	12.80	294.3	0.30	0.75	26,122
				U10000	EP102	575,339	4,593,229	149.35	0.15	12.80	294.3	0.30	0.75	26,122
				U20000	EP037	575,339	4,593,229	149.35	3.88	12.19	294.3	14.63	0.61	31,357
				U20000	EP049	575,339	4,593,229	149.35	3.88	12.50	294.3	14.63	0.61	32,140
				U20000	EP059	575,339	4,593,229	149.35	1.64	12.19	294.3	10.97	0.46	31,357
				U20000	EP062	575,339	4,593,229	149.35	2.42	12.19	294.3	9.14	0.61	31,357
				U20000	EP069	575,339	4,593,229	149.35	2.42	11.89	294.3	9.14	0.61	30,573
				U20000	EP070	575,339	4,593,229	149.35	2.42	11.89	294.3	9.14	0.61	30,573
				U20000	EP071	575,339	4,593,229	149.35	2.42	11.89	294.3	9.14	0.61	30,573
				U20000	EP106	575,339	4,593,229	149.35	3.88	12.19	294.3	14.63	0.61	31,357
				U20000	EP117	575,339	4,593,229	149.35	3.88	12.19	294.3	14.63	0.61	31,357
3335200039	BALL METAL BEVERAGE CONTAINER CORP	VOC	8.1	U-20200	40EP1	553,111	4,589,798	158.50	4.74	14.33	294.3	15.24	0.58	28,123
				U-20200	40EP2	553,190	4,590,008	158.50	4.74	14.33	294.3	15.24	0.58	28,123
				U-20200	40EP3	553,097	4,589,779	158.50	13.58	12.80	294.3	15.24	1.12	32,924
				U-20200	41EP1	553,190	4,590,008	158.50	5.14	14.33	294.3	15.33	0.69	36,844
				U-20200	42EP1	553,162	4,589,840	158.50	0.51	14.33	294.3	1.52	0.69	36,844
3392200003	BOWLINE POINT GENERATING STATION	SO_2, PM, NO_X	46.0	100001	1	587,032	4,562,023	3.05	554.60	87.17	417.6	34.75	5.72	464,353
				100002	2	587,032	4,562,023	3.05	554.60	87.17	404.3	25.60	5.72	331,230
				100004	4	0	0	13.72	4.53	35.36	596.5	16.15	1.37	881,980
3392600013	NOVARTIS - SUFFERN PLANT	SO_2	41.3		B0001	572,591	4,552,328	94.49	0.38	12.80	499.8	9.99	0.91	874,287
					B0002	572,591	4,552,328	94.49	0.52	11.28	483.2	12.39	0.91	679,293
					B0003	572,591	4,552,328	94.49	1.45	11.89	430.4	13.81	0.76	176,571
					B0004	572,591	4,552,328	94.49	0.15	11.89	441.5	7.75	0.46	353,220
					B0005	572,591	4,552,328	94.49	0.15	11.89	441.5	7.75	0.46	353,220
					B0006	572,591	4,552,328	94.49	0.15	11.89	441.5	7.75	0.46	353,220
3392600041	GOOD SAMARITAN HOSPITAL	SO_2	42.1	U00001	1	572,600	4,551,200	118.26	4.85	30.48	505.4	10.36	1.52	476,528

Table 1: PM_{10} Source Inventory (PSD/Large Source Analysis)

DEC	Facility Name	Major Pollutants	Distance from CPV (km)	Emission Unit ID	Emission Point ID	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions (lb/hr)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)	M-Value
3392800030	STONY POINT FACILITY	PM, NO_X	44.9	UOOORD	4	586,432	4,563,223	3.96	11.02	13.41	394.3	20.73	0.97	57,767
				UBD1KN	8	586,432	4,563,223	3.96	32.43	9.14	366.5	15.24	1.52	22,803
				UBD2KN	11	586,432	4,563,223	3.96	34.88	6.10	588.7	42.98	1.07	31,366
				UOOOCB	19	586,432	4,563,223	3.96	3.37	26.52	308.7	18.29	0.46	57,954
				UOOOCB	21	586,432	4,563,223	3.96	2.38	17.07	322.0	14.33	0.48	48,043
				UOO3RM	30	586,432	4,563,223	3.96	0.00	34.44	394.3	22.56	0.30	253,393,814
				UOO3RM	32	586,432	4,563,223	17.98	0.00	20.42	294.3	13.11	0.29	58,824,588
				UOO1RM	34	586,432	4,563,223	3.96	0.00	31.39	366.5	15.24	0.30	2,030,913,366
				UOO2RM	35	586,432	4,563,223	3.96	0.00	31.39	366.5	15.24	0.30	2,030,913,366
				UORECL	39	586,432	4,563,223	4.27	6.38	15.24	338.7	17.68	0.71	45,116
				UORECL	65	586,432	4,563,223	4.27	1.11	16.15	366.5	37.80	0.20	51,745
				UOOOK4	31	586,432	4,563,223	3.96	5.15	23.17	477.6	19.20	0.69	120,870
				UOOOK4	40	586,432	4,563,223	4.27	0.10	30.48	588.7	14.43	0.69	7,592,470
				U123LP	50	586,432	4,563,223	3.96	2.94	25.60	355.4	17.68	0.43	63,663
				URDAIR	51	586,432	4,563,223	3.96	0.51	26.21	355.4	17.37	0.20	81,417
				UOCRSR	52	586,432	4,563,223	3.96	0.01	6.71	294.3	16.46	0.29	3,087,219
				UOOOK3	38	586,432	4,563,223	3.96	2.40	35.05	422.0	22.56	0.43	161,620
				UOOOK3	53	586,432	4,563,223	4.27	0.30	1.52	588.7	8.21	1.02	158,075
				UOOOK2	54	586,432	4,563,223	4.27	0.25	9.14	588.7	11.98	1.02	1,659,699
				UOOOK1	36	586,432	4,563,223	4.27	2.40	20.12	422.0	22.56	0.43	92,756
				UOOOK1	55	586,432	4,563,223	4.27	0.30	35.05	588.7	8.21	1.02	3,635,724
				USTDST	33	586,432	4,563,223	3.96	0.08	21.03	355.4	6.71	0.13	65,323
				USTDST	59	586,432	4,563,223	4.88	1.07	21.95	355.4	16.15	0.30	68,163
				UBDSTC	60	586,432	4,563,223	3.96	0.65	4.57	322.0	17.37	0.20	10,009
				UBDSTC	61	586,432	4,563,223	10.97	0.40	7.01	322.0	35.05	0.13	19,732
				U0BSNV	62	586,432	4,563,223	3.96	0.22	12.19	294.3	19.51	0.13	31,357
				U0BSNV	63	586,432	4,563,223	3.96	0.47	0.61	310.9	3.96	0.41	1,657
				U0BSNV	64	586,432	4,563,223	3.96	0.22	12.19	294.3	19.51	0.13	31,357
				U2BDDY	70	586,432	4,563,223	5.18	0.15	10.06	294.3	13.11	0.13	25,869
				U2BDDY	71	586,432	4,563,223	5.18	0.35	11.28	294.3	30.18	0.13	29,005
				U2BDDY	72	586,432	4,563,223	5.18	0.18	8.84	310.9	24.69	0.10	24,021
				U2BDDY	73	586,432	4,563,223	5.18	0.25	5.49	310.9	33.53	0.10	14,910
				U2BDDY	74	586,432	4,563,223	5.18	0.13	6.10	310.9	7.62	0.15	16,566
				U2BDDY	75	586,432	4,563,223	5.18	3.46	6.71	294.3	17.07	0.47	13,296
				U2BDDY	76	586,432	4,563,223	5.18	0.32	6.10	310.9	43.59	0.10	16,566
				U2BDDY	77	586,432	4,563,223	5.18	0.13	3.05	310.9	17.37	0.10	8,283
				U1BDDY	85	586,432	4,563,223	5.18	0.70	15.24	294.3	15.24	0.22	28,221
				U1BDDY	86	586,432	4,563,223	5.18	1.29	14.33	355.4	57.00	0.18	44,496
				U1BDDY	87	586,432	4,563,223	5.18	0.34	15.85	310.9	46.63	0.10	43,072
				U1BDDY	88	586,432	4,563,223	5.18	0.15	10.36	294.3	13.11	0.13	26,653
				U1BDDY	89	586,432	4,563,223	5.18	0.34	10.36	294.3	29.87	0.13	26,653
				U1BDDY	92	586,432	4,563,223	5.18	0.20	7.01	294.3	17.07	0.13	18,030
				U00DUN	93	586,432	4,563,223	5.18	3.46	6.71	294.3	17.07	0.47	13,296
				U2STUC	94	586,432	4,563,223	5.18	0.51	10.67	355.4	44.50	0.13	33,135
				U2STUC	95	586,432	4,563,223	5.18	1.21	11.28	355.4	15.54	0.30	29,018
3551200041	BASF CORP	PM	44.6	EU001A	EP001	589,500	4,571,200	9.14	0.20	12.50	477.6	18.29	0.76	1,975,351
				EU0028	EP008	589,500	4,571,200	9.14	1.35	8.23	333.2	42.67	0.51	139,410

Table 1: PM_{10} Source Inventory (PSD/Large Source Analysis)

DEC	Facility Name	Major Pollutants	Distance from CPV (km)	Emission Unit ID	Emission Point ID	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions (lb/hr)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)	M-Value
				EU0029	EP012	589,500	4,571,200	9.14	1.76	9.14	291.5	26.82	0.25	16,336
				EU0029	EP013	589,500	4,571,200	9.14		9.14	291.5	10.06	0.15	2,205
				EU0011	EP021	589,500	4,571,200	9.14	1.07	10.97	338.7	12.19	0.36	33,381
				EU0011	EP022	589,500	4,571,200	9.14		10.06	294.3	17.37	0.20	12,370
				EU0011	EP023	589,500	4,571,200	9.14		10.06	291.5	19.51	0.20	13,758
				EU0011	EP109	589,500	4,571,200	9.14		9.75	463.7	18.29	0.61	179,069
				EU0021	EP025	589,500	4,571,200	9.14	2.14	14.02	294.3	14.33	0.46	36,060
				EU0003	EP034	589,500	4,571,200	9.14	1.44	10.97	294.3	17.37	0.20	10,027
				EU0006	EP038	589,500	4,571,200	9.14	1.49	15.85	333.2	11.28	0.51	64,292
				EU0022	EP039	589,500	4,571,200	9.14	2.05	10.97	316.5	11.28	0.76	69,148
				EU0012	EP040	589,500	4,571,200	9.14	1.00	10.97	338.7	16.15	0.30	34,770
				EU0012	EP041	589,500	4,571,200	9.14		10.97	294.3	11.28	0.25	14,644
				EU0012	EP042	589,500	4,571,200	9.14		10.97	294.3	11.28	0.25	14,644
				EU0035	EP043	589,500	4,571,200	9.14	2.05	12.19	294.3	11.28	0.51	31,750
				EU0013	EP044	589,500	4,571,200	9.14	1.00	11.58	338.7	16.15	0.30	36,701
				EU0013	EP045	589,500	4,571,200	9.14		10.97	294.3	7.62	0.30	14,249
				EU0013	EP046	589,500	4,571,200	9.14		10.97	294.3	7.62	0.30	14,249
				EU0013	EP110	589,500	4,571,200	9.14		12.80	463.7	18.29	0.71	342,292
				EU0007	EP047	589,500	4,571,200	9.14	1.75	17.98	316.5	9.75	0.46	41,333
				EU0007	EP048	589,500	4,571,200	9.14		16.76	294.3	11.28	0.25	12,785
				EU0002	EP052	589,500	4,571,200	9.14	1.73	17.98	316.5	11.58	0.51	61,297
				EU0002	EP020	589,500	4,571,200	9.14		10.97	293.2	15.54	0.23	9,415
				EU0002	EP100	589,500	4,571,200	9.14		10.97	505.4	13.72	0.20	11,316
				EU0002	EP101	589,500	4,571,200	9.14		10.97	330.4	14.02	0.25	11,816
				EU0008	EP053	589,500	4,571,200	9.14	1.11	10.67	316.5	11.58	0.30	20,402
				EU0008	EP054	589,500	4,571,200	9.14		10.06	330.4	17.37	0.20	13,387
				EU0014	EP055	589,500	4,571,200	9.14	1.00	12.50	294.3	11.28	0.25	16,678
				EU0014	EP056	589,500	4,571,200	9.14		12.50	294.3	11.28	0.25	16,678
				EU0014	EP057	589,500	4,571,200	9.14		12.19	338.7	16.15	0.30	38,633
				EU0014	EP104	589,500	4,571,200	9.14	0.40	13.72	435.9	10.85	0.95	918,453
				EU0033	EP060	589,500	4,571,200	9.14	0.71	6.10	294.3	24.69	0.20	16,055
				EU0015	EP062	589,500	4,571,200	9.14	0.50	12.19	338.7	16.15	0.30	77,266
				EU0015	EP063	589,500	4,571,200	9.14		12.19	294.3	11.28	0.25	32,543
				EU0009	EP064	589,500	4,571,200	9.14	1.11	9.75	330.4	17.37	0.20	12,981
				EU0009	EP065	589,500	4,571,200	9.14		10.06	316.5	26.21	0.20	19,349
				EU0010	EP067	589,500	4,571,200	9.14	1.11	3.66	316.5	11.58	0.30	6,995
				EU0010	EP068	589,500	4,571,200	9.14		9.75	330.4	17.37	0.20	12,981
				EU0010	EP119	589,500	4,571,200	9.14		16.46	402.6	21.34	0.25	51,224
				EU0016	EP069	589,500	4,571,200	9.14	1.00	12.19	294.3	11.28	0.25	16,272
				EU0016	EP070	589,500	4,571,200	9.14		11.58	560.9	6.10	0.30	22,936
				EU0016	EP105	589,500	4,571,200	9.14		12.50	435.9	16.19	0.75	306,369
				EU0017	EP072	589,500	4,571,200	9.14	1.00	12.80	294.3	11.28	0.25	17,085
				EU0017	EP073	589,500	4,571,200	9.14		11.58	566.5	2.74	0.30	10,423
				EU0017	EP106	589,500	4,571,200	9.14		12.50	435.9	16.19	0.75	306,369
				EU0019	EP074	589,500	4,571,200	9.14	1.11	11.58	330.4	17.37	0.20	15,415
				EU0019	EP075	589,500	4,571,200	9.14		7.92	316.5	11.58	0.30	15,156
				EU001B	EP076	589,500	4,571,200	9.14	0.84	12.80	477.6	18.29	0.76	481,793
				EU0036	EP108	589,500	4,571,200	9.14	0.21	3.05	699.8	36.58	0.36	304,799
				EU0034	EP111	589,500	4,571,200	9.14	0.21	12.80	293.2	0.30	0.15	789
				EU0034	EP107	589,500	4,571,200	9.14		17.37	293.2	0.00	0.36	
				EU0037	EP113	589,500	4,571,200	9.14	0.52	9.75	477.6	14.33	0.30	74,607

Table 1: PM_{10} Source Inventory (PSD/Large Source Analysis)

DEC	Facility Name	Major Pollutants	Distance from CPV (km)	Emission Unit ID	Emission Point ID	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions (lb/hr)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)	M-Value
				EU0038	EP114	589,500	4,571,200	9.14	0.67	12.80	293.2	24.69	0.20	35,646
				EU0039	EP115	589,500	4,571,200	9.14	0.28	12.50	810.9	21.95	0.23	255,997
3552200087	LAFARGE NORTH AMERICA INC - BUCHANAN	PM_{10}	46.1	0.00E+00	0PT17	590,500	4,569,500	18.29	0.30	31.70	338.7	22.43	0.61	1,859,825
				0.00E+00	0PT30	590,500	4,569,500	19.51	17.53	30.48	394.3	7.62	1.98	127,802
				0.00E+00	0PT31	590,500	4,569,500	19.51	0.00	30.48	338.7	16.46	1.78	1,717,176,755
				0.00E+00	0PT38	590,500	4,569,500	19.51	5.23	23.77	255.4	18.90	1.68	384,312
334600267	NEW ENGLAND LAMINATES	VOC, HAP	29.0	00001	1	573,787	4,595,694	150.88	0.09	10.36	422.0	18.29	0.61	2,058,733
				00001	2	573,787	4,595,694	150.88	0.09	10.36	422.0	18.29	0.61	2,058,733
				00001	3	573,787	4,595,694	150.88	0.15	10.36	422.0	18.29	0.61	1,235,240

Table 2: Multisource PM_{10} Modeling Inventory (PSD/Large Source Analysis)[1]

DEC	Facility Name	Merged Emission Point IDs	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions[2] (g/s)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)
3130200017	CHEMPRENE INC	5	585,532	4,593,724	61.57	0.43	1.83	294.3	16.76	0.53
		1, 2	585,532	4,593,624	61.57	0.58	3.66	294.3	15.54	0.46
		113, 8	585,532	4,593,624	61.57	0.71	4.27	294.3	16.76	0.61
		7	585,532	4,593,624	61.57	0.15	10.67	422.0	15.54	0.61
3134600019	DUTCHESS CO RESOURCE RECOVERY FACILITY	FLUE1, FLUE2	588,032	4,611,524	20.42	0.63	60.96	477.6	24.38	1.22
3134600035	IBM CORP SOUTH RD FACILITY	442XF, W42SL	588,532	4,611,924	27.43	0.10	2.44	294.3	1.22	0.61
		W42AK, 342KC, 342SC, 342LB, 643AB, 643AA, W42ST	588,532	4,611,924	27.43	0.92	4.88	294.3	2.44	0.30
		W42GD, W42WH, W42WG, 342CP	588,532	4,611,924	27.43	0.89	7.92	294.3	1.83	0.36
		342BG, W42CA, 342WF, 342BL, 342WM, 342WE,	588,532	4,611,924	27.43	1.15	14.94	294.3	3.05	0.75
		342MA, 342MB, 343PF, 342CD, 342MC, 342CK, 342FA, 342WG, 342WH, 342WL,	588,532	4,611,924	27.43	2.07	15.85	294.3	6.71	0.91
		D42TA, D42TG	588,532	4,611,924	27.43	1.72	20.73	294.3	10.36	0.91
		W42AM, SR006	588,532	4,611,924	27.43	0.87	30.18	294.3	3.96	0.20
		SR007, 242NI, SR001, SR003, SR002	588,532	4,611,924	27.43	3.52	15.24	505.4	17.07	0.91
3134600067	VASSAR COLLEGE	CHL01	592,000	4,615,600	45.11	0.06	6.10	505.4	8.53	0.51
		BLR03, BLR04, BLR01, BLR02, BLR05	592,000	4,615,600	45.11	1.66	15.24	505.4	6.71	0.91
3330900101	ORANGE RECYCLING & ETHANOL PROD FAC	1	548,115	4,586,340	153.32	3.41	30.48	408.7	12.80	2.64
		4, 5, 6, 7, 8, 9, 10, 11	548,115	4,586,340	150.27	0.66	11.58	302.6	13.72	3.35
3331100114	PRISMATIC DYEING & FINISHING INC	36	580,200	4,594,700	30.48	0.24	6.10	533.2	10.36	0.61
3334800084	METAL CONTAINER CORP	EP066, EP067, EP102	575,339	4,593,229	149.35	0.06	12.80	294.3	0.30	0.75
		EP069, EP070, EP071, EP062, EP037, EP106, EP117, EP059, EP030, EP049	575,339	4,593,229	149.35	5.24	11.89	294.3	9.14	0.61
3335200039	BALL METAL BEVERAGE CONTAINER CORP	40EP1, 40EP2	553,111	4,589,798	158.50	1.19	14.33	294.3	15.24	0.58
		40EP3	553,097	4,589,779	158.50	1.71	12.80	294.3	15.24	1.12
		41EP1, 42EP1	553,190	4,590,008	158.50	0.71	14.33	294.3	15.33	0.69
3392200003	BOWLINE POINT GENERATING STATION	2, 1	587,032	4,562,023	3.05	139.76	87.17	404.3	25.60	5.72
		4	587,032	4,562,023	3.05	0.57	35.36	596.5	16.15	1.37
3392600013	NOVARTIS - SUFFERN PLANT	B0001	572591	4552328	94.49	0.05	12.80	499.8	9.99	0.33
		B0002	572591	4552328	94.49	0.07	11.28	483.2	12.39	0.29
		B0003	572591	4552328	94.49	0.18	11.89	430.4	13.81	0.30
		B0004, B0005, B0006	572591	4552328	94.49	0.06	11.89	441.5	7.75	0.30

Table 2: Multisource PM_{10} Modeling Inventory (PSD/Large Source Analysis)[1]

DEC	Facility Name	Merged Emission Point IDs	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions[2] (g/s)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)
3392600041	GOOD SAMARITAN HOSPITAL	1	572,600	4,551,200	118.26	0.61	30.48	505.4	10.36	1.52
3392800030	STONY POINT FACILITY	63, 77	586,432	4,563,223	3.96	0.07	0.61	310.9	3.96	0.41
		60, 75, 93, 73, 74, 76, 92, 61	586,432	4,563,223	3.96	1.12	4.57	322.0	17.37	0.20
		8, 72, 70, 88, 89, 85, 71,	586,432	4,563,223	3.96	4.47	9.14	366.5	15.24	1.52
		62, 64, 11, 94	586,432	4,563,223	3.96	4.52	12.19	294.3	19.51	0.13
		87, 86, 39, 21	586,432	4,563,223	3.96	1.31	15.85	310.9	46.63	0.10
		65, 4, 19	586,432	4,563,223	3.96	1.95	16.15	366.5	37.80	0.20
		50, 33, 59	586,432	4,563,223	3.96	0.51	25.60	355.4	17.68	0.43
		51, 36	586,432	4,563,223	3.96	0.37	26.21	355.4	17.37	0.20
		31, 53, 38	586,432	4,563,223	3.96	0.99	23.17	477.6	19.20	0.69
		54, 52, 55, 40, 32, 30, 34, 35	586,432	4,563,223	3.96	0.08	9.14	588.7	11.98	1.02
3551200041	BASF CORP	EP034, EP060	589,500	4,571,200	9.14	0.27	10.97	294.3	17.37	0.20
		EP043, EP114, EP025	589,500	4,571,200	9.14	0.61	12.19	294.3	11.28	0.51
		EP038, EP039, EP113	589,500	4,571,200	9.14	0.45	15.85	333.2	11.28	0.51
		EP008, EP108, EP115, EP076, EP104, EP001, EP012	589,500	4,571,200	9.14	0.48	8.23	333.2	42.67	0.51
		EP013, EP021	589,500	4,571,200	9.14	0.22	9.14	291.5	10.06	0.15
		EP022, EP023, EP109, EP040	589,500	4,571,200	9.14	0.13	10.06	294.3	17.37	0.20
		EP041, EP042, EP044	589,500	4,571,200	9.14	0.13	10.97	294.3	11.28	0.25
		EP045, EP046, EP110, EP047	589,500	4,571,200	9.14	0.13	10.97	294.3	7.62	0.30
		EP048, EP052	589,500	4,571,200	9.14	0.22	16.76	294.3	11.28	0.25
		EP020, EP100, EP101, EP053	589,500	4,571,200	9.14	0.22	10.97	293.2	15.54	0.23
		EP054, EP055, RP056, EP057, EP062	589,500	4,571,200	9.14	0.14	10.06	330.4	17.37	0.20
		EP063	589,500	4,571,200	9.14	0.06	12.19	294.3	11.28	0.25
		EP064, EP065	589,500	4,571,200	9.14	0.14	9.75	330.4	17.37	0.20
		EP067, EP068, EP119	589,500	4,571,200	9.14	0.14	3.66	316.5	11.58	0.30
		EP069, EP070, EP105, EP072	589,500	4,571,200	9.14	0.13	12.19	294.3	11.28	0.25
		EP073, EP106, EP074	589,500	4,571,200	9.14	0.13	11.58	566.5	2.74	0.30
		EP075	589,500	4,571,200	9.14	0.14	7.92	316.5	11.58	0.30
		EP111, EP107	589,500	4,571,200	9.14	0.03	12.80	293.2	0.30	0.15

Table 2: Multisource PM_{10} Modeling Inventory (PSD/Large Source Analysis)[1]

DEC	Facility Name	Merged Emission Point IDs	UTM E (m)	UTM N (m)	Base Elevation (m)	Potential PM_{10} Emissions[2] (g/s)	Stack Height (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)	Stack Diameter (m)
3552200087	LAFARGE NORTH AMERICA INC - BUCHANAN	0PT30	590,500	4,569,500	19.51	2.21	30.48	394.3	7.62	1.98
		0PT38	590,500	4,569,500	19.51	0.66	23.77	255.4	18.90	1.68
		0PT17	590,500	4,569,500	18.29	0.04	31.70	338.7	22.43	0.61
334600267	NEW ENGLAND LAMINATES	3	573,787	4,595,694	150.88	0.02	10.36	422.0	18.29	0.61
		1, 2	573,787	4,595,694	150.88	0.02	10.36	422.0	18.29	0.61

[1] Modeled all PM_{10} sources in the NAAQS and PSD increment analyses.

[2] Modeled the potential short-term PM_{10} emission rates in 24-hour and annual analyses.

APPENDIX I

PLOTS OF PROJECT PM-2.5 IMPACTS

Figure I-1

Maximum Project Impacts
Annual Average PM Concentrations

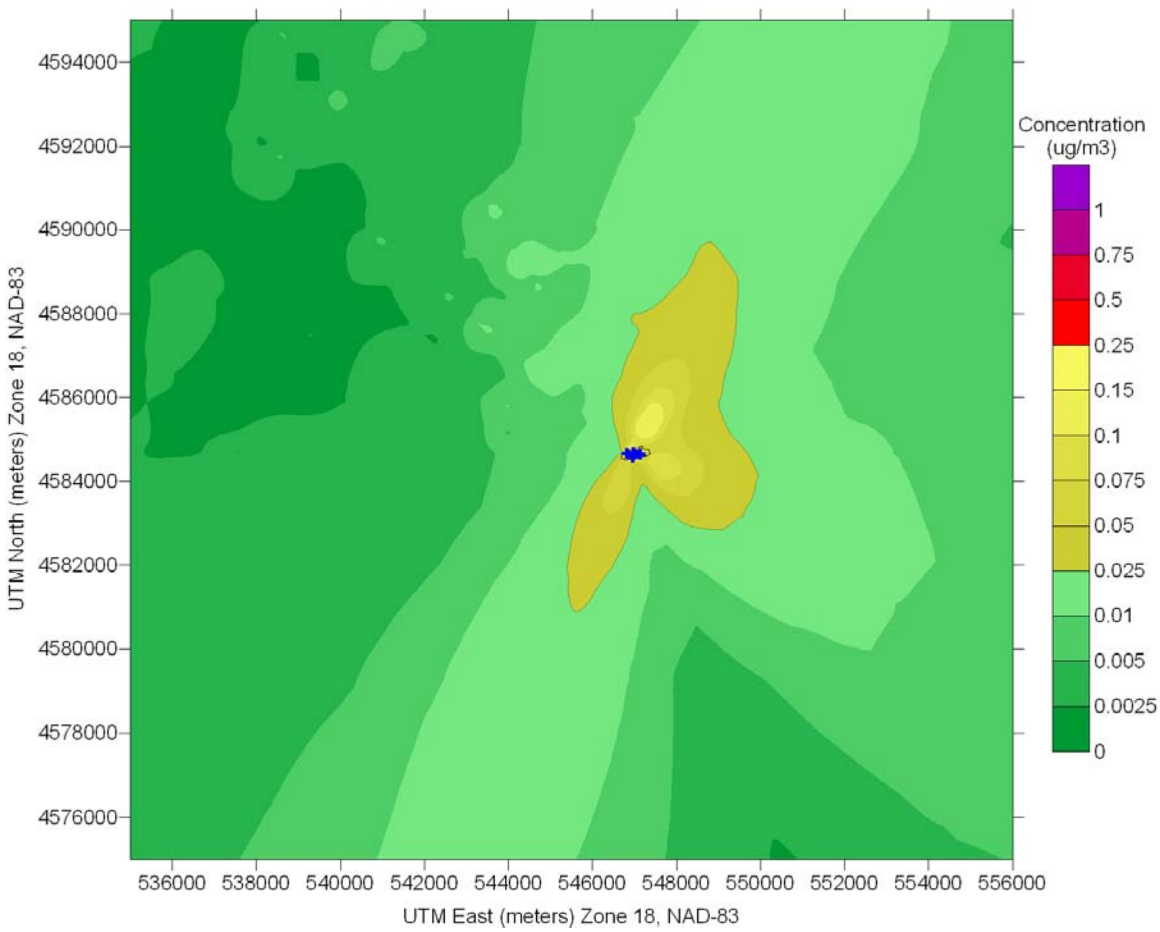


Figure I-2

Maximum Project Impacts
24-Hour Average PM Concentrations

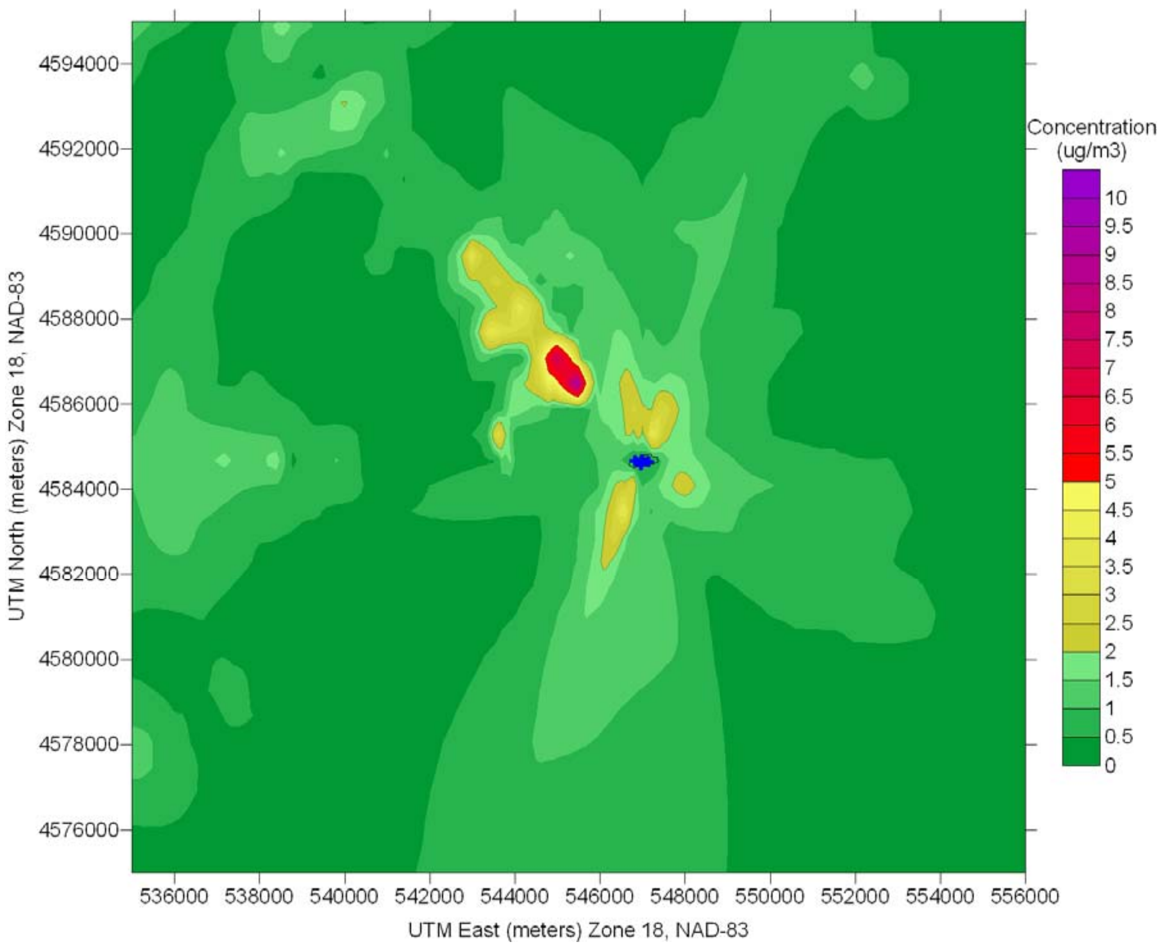
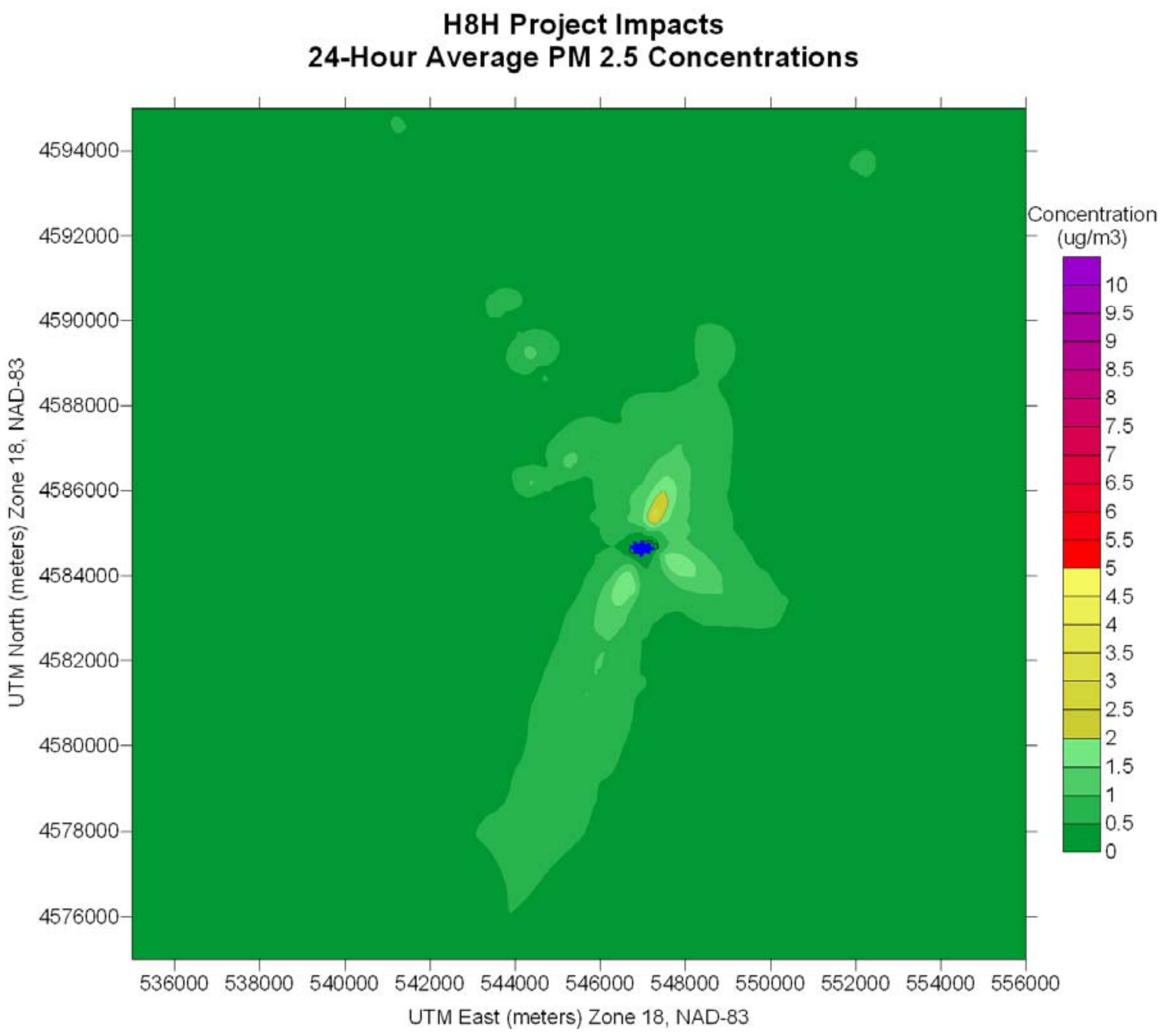


Figure I-3


H8H Project Impacts
24-Hour Average PM 2.5 Concentrations
4594000
4592000
4590000
4588000
4586000
4584000
4582000
4580000
4578000
4576000
UTM North (meters) Zone 18, NAD-83
536000 538000 540000 542000 544000 546000 548000 550000 552000 554000 556000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
10
9.5
9
8.5
8
7.5
7
6.5
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0

APPENDIX J

VISCREEN MODEL OUTPUT FILES

Visual Effects Screening Analysis for
Source: CPV Valley - Oil
Class I Area: Brigantine Wilderness

*** Level-1 Screening ***

Input Emissions for

Particulates	103.40	LB /HR
NOx (as NO2)	131.32	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	2.02	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	159.00 km
Source-Observer Distance:	206.00 km
Min. Source-Class I Distance:	206.00 km
Max. Source-Class I Distance:	206.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	206.0	84.	2.00	.493	.05	.007
SKY	140.	84.	206.0	84.	2.00	.107	.05	-.004
TERRAIN	10.	84.	206.0	84.	2.00	.275	.05	.003
TERRAIN	140.	84.	206.0	84.	2.00	.050	.05	.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	5.	64.2	164.	2.00	.790	.05	.007
SKY	140.	5.	64.2	164.	2.00	.189	.05	-.004
TERRAIN	10.	5.	64.2	164.	2.00	.366	.05	.003
TERRAIN	140.	5.	64.2	164.	2.00	.137	.05	.003

Visual Effects Screening Analysis for
Source: CPV Valley - Oil
Class I Area: Lye Brook Wilderness

*** Level-1 Screening ***

Input Emissions for

Particulates	103.40	LB /HR
NOx (as NO2)	131.32	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	2.02	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	195.00 km
Source-Observer Distance:	215.00 km
Min. Source-Class I Distance:	215.00 km
Max. Source-Class I Distance:	215.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	215.0	84.	2.00	.647	.05	.010
SKY	140.	84.	215.0	84.	2.00	.130	.05	-.005
TERRAIN	10.	84.	215.0	84.	2.00	.411	.05	.004
TERRAIN	140.	84.	215.0	84.	2.00	.064	.05	.002

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	5.	67.0	164.	2.00	1.519	.05	.015
SKY	140.	5.	67.0	164.	2.00	.333	.05	-.007
TERRAIN	10.	5.	67.0	164.	2.00	.649	.05	.005
TERRAIN	140.	5.	67.0	164.	2.00	.250	.05	.005

Visual Effects Screening Analysis for
Source: CPV Valley - Oil
Class I Area: Catskill State Park

*** Level-1 Screening ***

Input Emissions for

Particulates	103.40	LB /HR
NOx (as NO2)	131.32	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	2.02	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	60.00 km
Min. Source-Class I Distance:	60.00 km
Max. Source-Class I Distance:	103.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	60.0	84.	2.00	1.071	.05	.011
SKY	140.	84.	60.0	84.	2.00	.261	.05	-.009
TERRAIN	10.	84.	60.0	84.	2.00	.554	.05	.007
TERRAIN	140.	84.	60.0	84.	2.00	.113	.05	.005

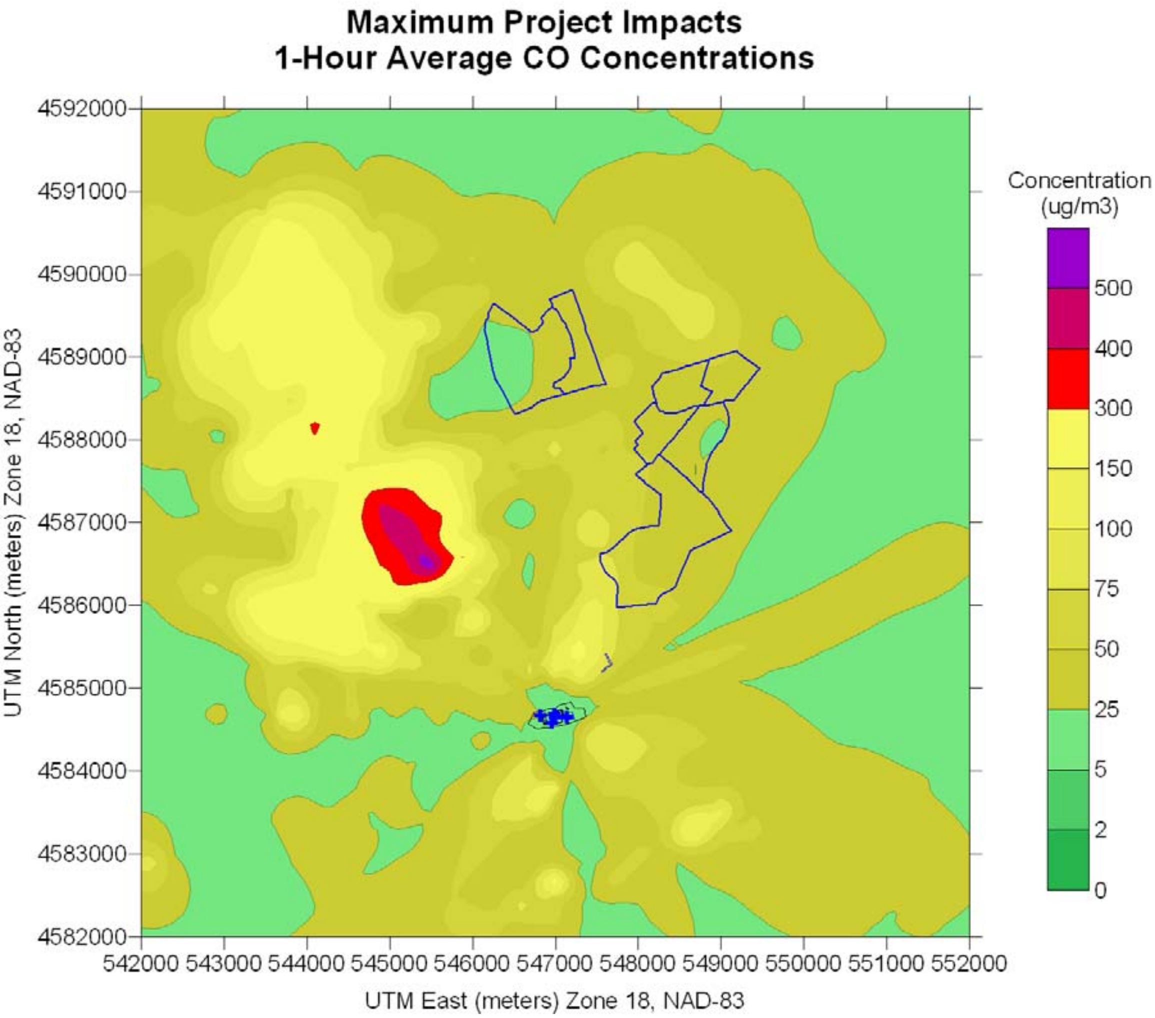
Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	30.	45.5	139.	2.00	1.286	.05	.013
SKY	140.	30.	45.5	139.	2.00	.236	.05	-.011
TERRAIN	10.	45.	51.0	124.	2.00	.710	.05	.008
TERRAIN	140.	45.	51.0	124.	2.00	.157	.05	.006

APPENDIX K

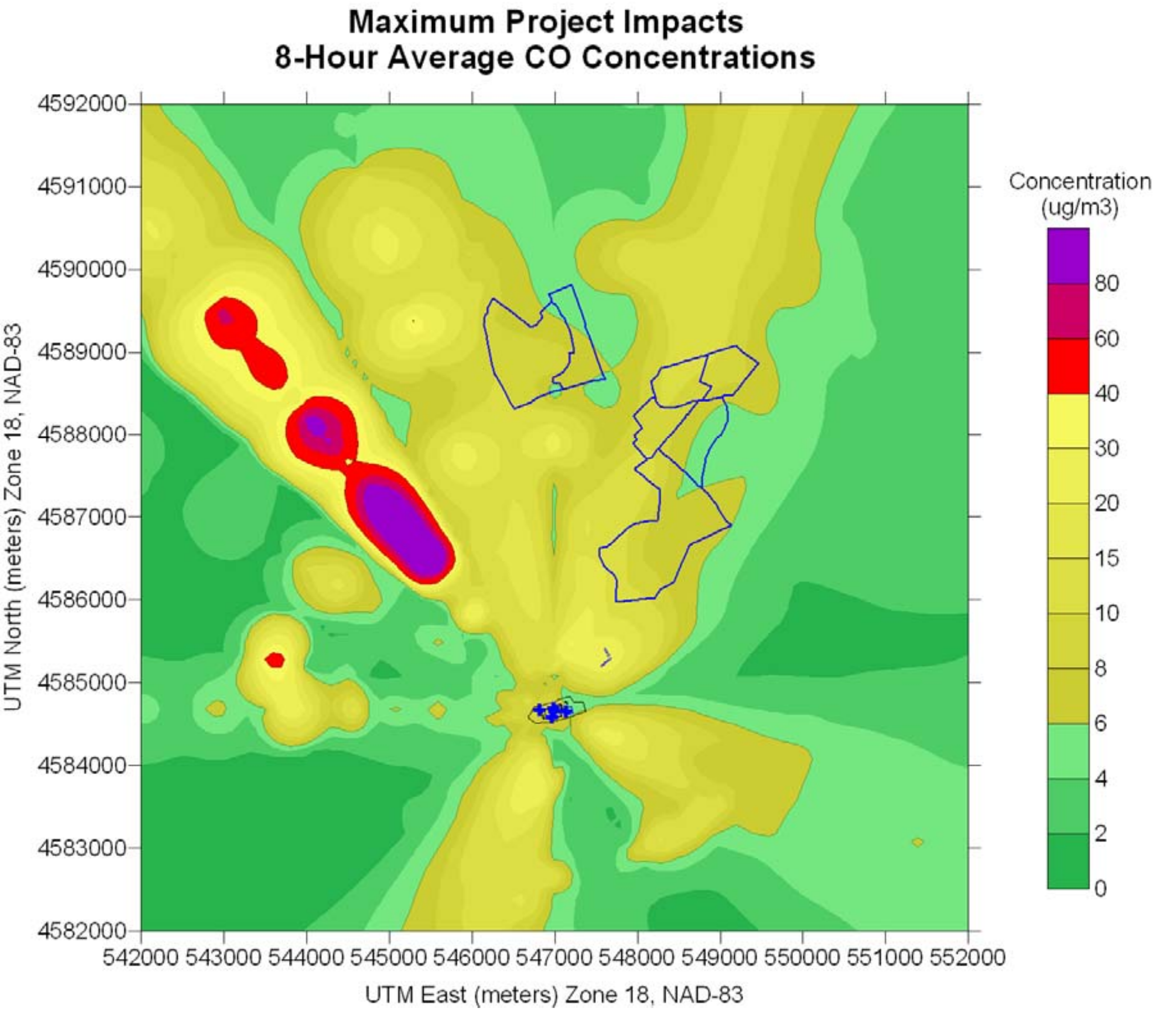
PLOTS OF MAXIMUM PREDICTED IMPACTS

Figure K-1



Maximum Project Impacts
1-Hour Average CO Concentrations
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
500
400
300
150
100
75
50
25
5
2
0

Figure K-2



Maximum Project Impacts
8-Hour Average CO Concentrations
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
80
60
40
30
20
15
10
8
6
4
2
0

Figure K-3

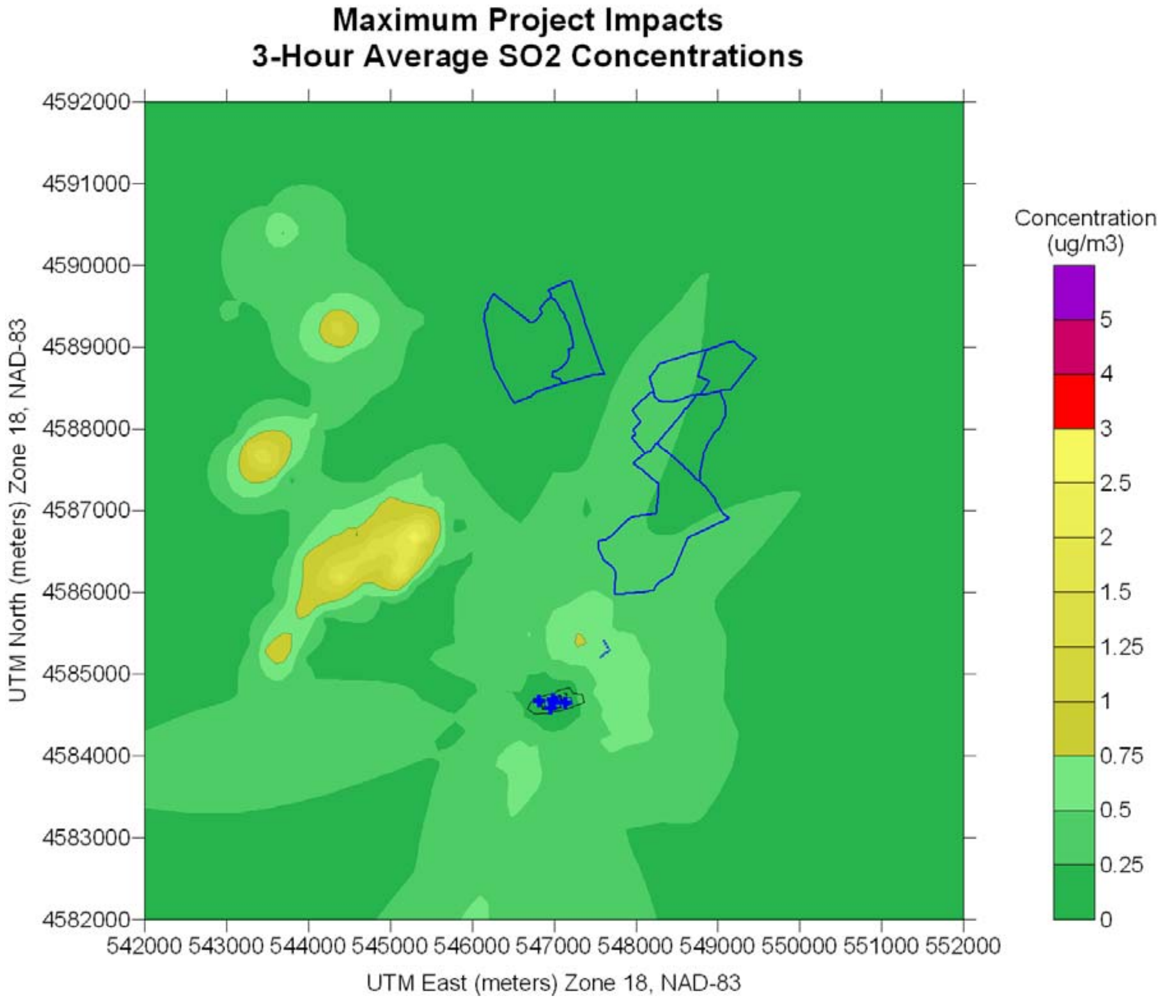
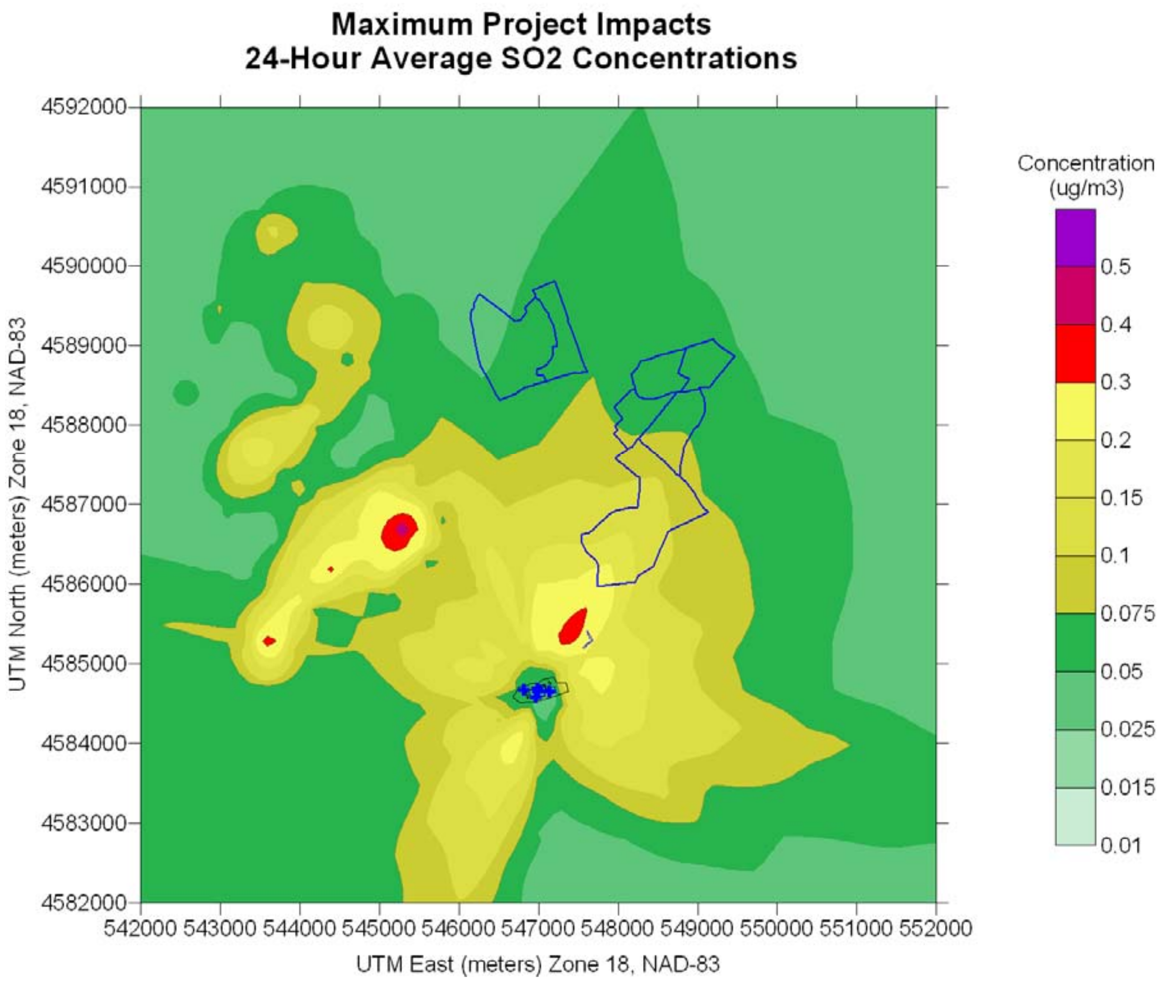
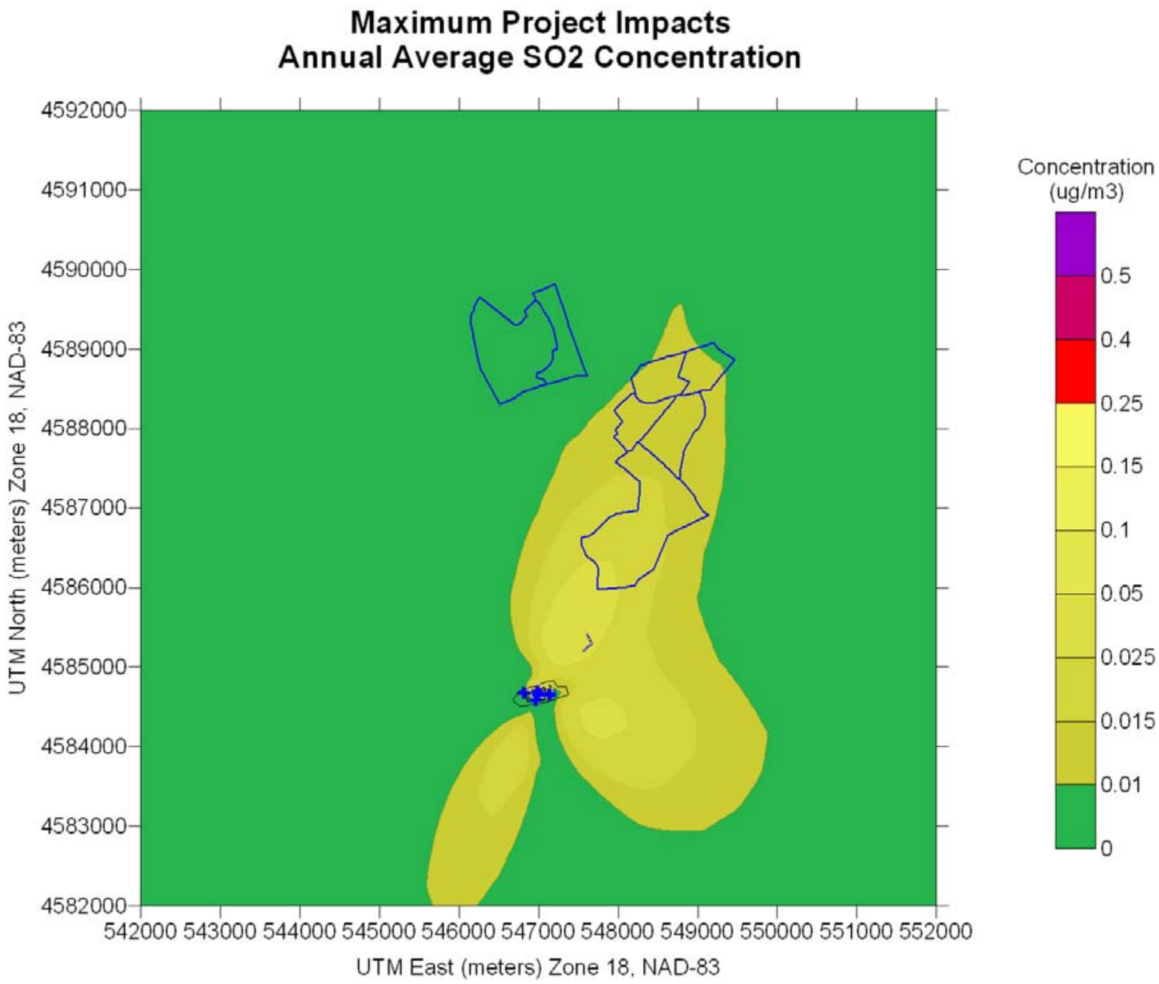

Maximum Project Impacts
3-Hour Average SO2 Concentrations
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
5
4
3
2.5
2
1.5
1.25
1
0.75
0.5
0.25
0

Figure K-4



Maximum Project Impacts
24-Hour Average SO2 Concentrations
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration
(ug/m3)
0.5
0.4
0.3
0.2
0.15
0.1
0.075
0.05
0.025
0.015
0.01

Figure K-5



Maximum Project Impacts
Annual Average SO2 Concentration
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration
(ug/m3)
0.5
0.4
0.25
0.15
0.1
0.05
0.025
0.015
0.01
0

Figure K-6

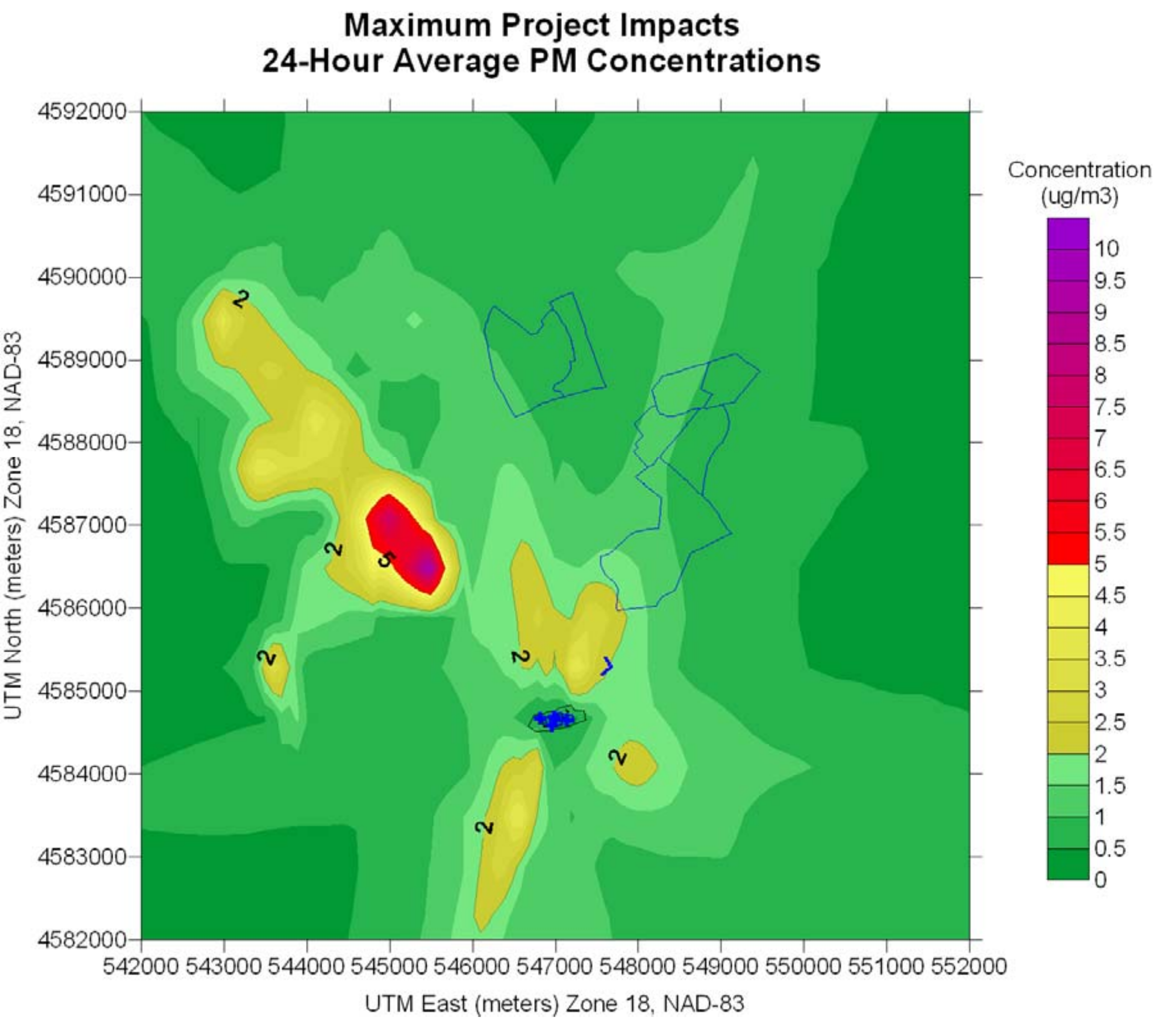
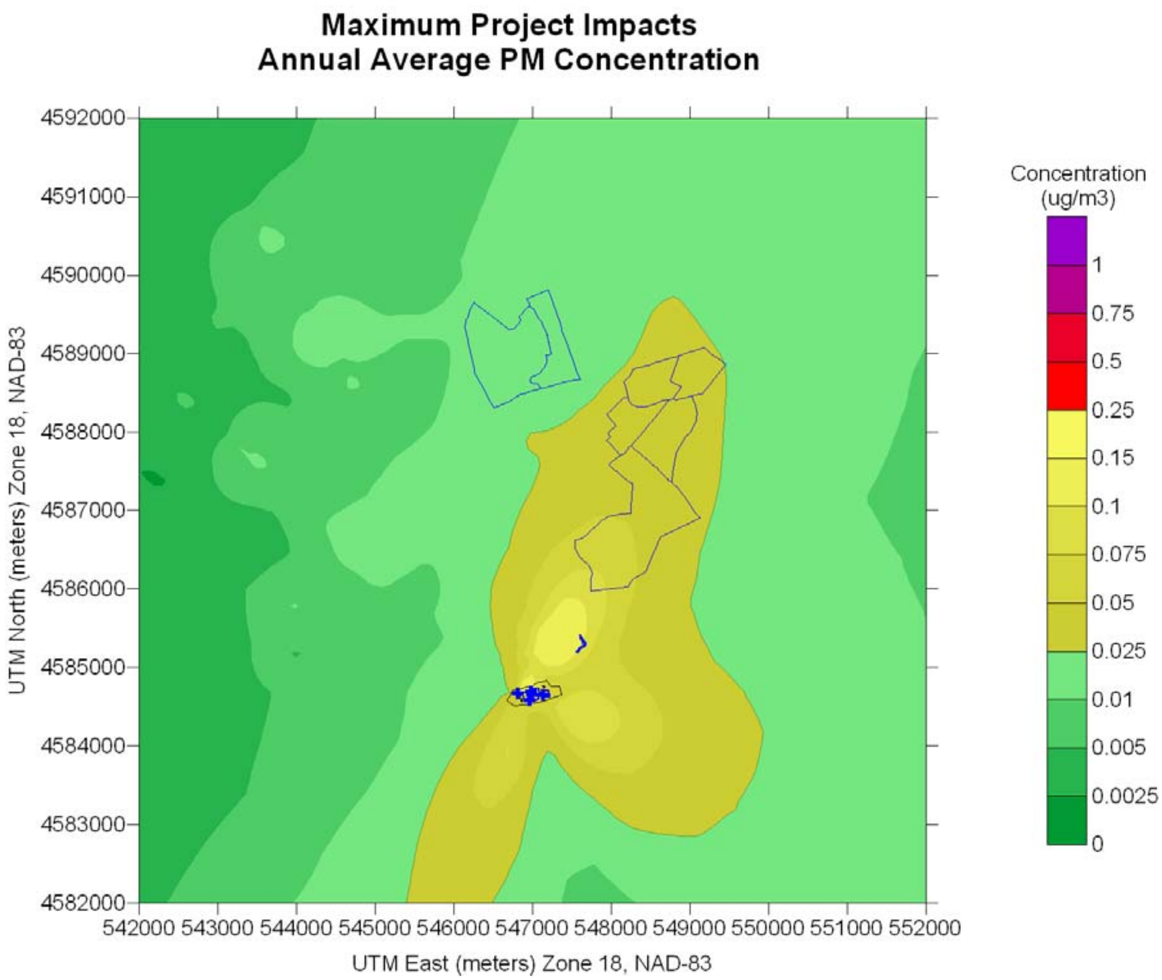
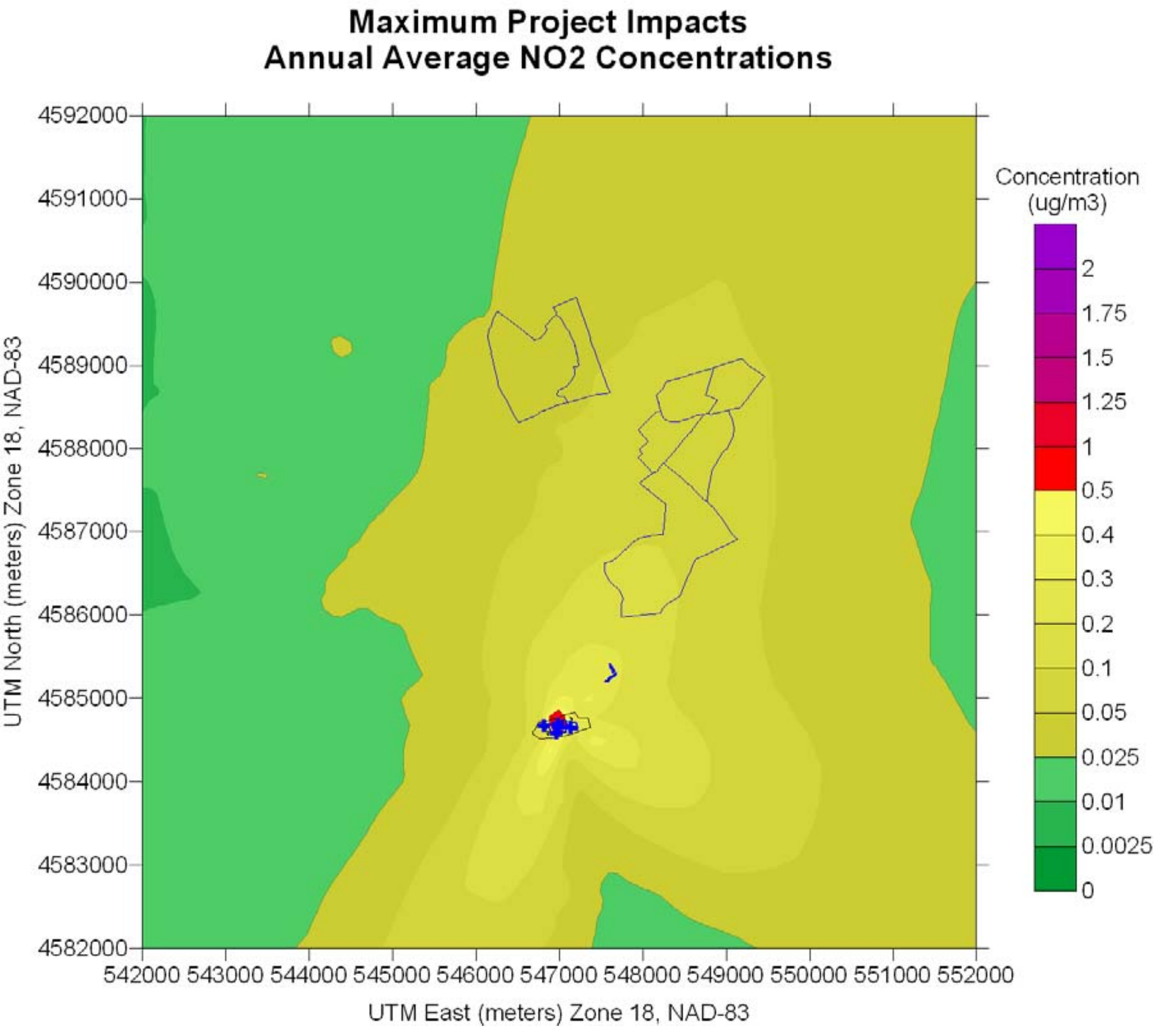

Maximum Project Impacts
24-Hour Average PM Concentrations
UTM North (meters) Zone 18, NAD-83
UTM East (meters) Zone 18, NAD-83
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
Concentration (ug/m3)
10
9.5
9
8.5
8
7.5
7
6.5
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0

Figure K-7



Maximum Project Impacts
Annual Average PM Concentration
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
1
0.75
0.5
0.25
0.15
0.1
0.075
0.05
0.025
0.01
0.005
0.0025
0

Figure K-8



Maximum Project Impacts
Annual Average NO2 Concentrations
4592000
4591000
4590000
4589000
4588000
4587000
4586000
4585000
4584000
4583000
4582000
UTM North (meters) Zone 18, NAD-83
542000 543000 544000 545000 546000 547000 548000 549000 550000 551000 552000
UTM East (meters) Zone 18, NAD-83
Concentration (ug/m3)
2
1.75
1.5
1.25
1
0.5
0.4
0.3
0.2
0.1
0.05
0.025
0.01
0.0025
0