United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
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N3615 (2350)

May 23, 2014

New Mexico Environment Department
Air Quality Bureau
Attn: Daren Zigich
525 Camino de los Marquez, Suite 1
Santa Fe NM 87505-1816

Re: Lea Power Partners, Permit No. PSD3449-M2 and TEMPO Agency Interest ID No. 25726

Dear Mr. Zigich:

We have been asked by Acting Superintendent Doug Neighbor to submit these comments on behalf of Carlsbad Caverns National Park (NP). Carlsbad Caverns NP is a World Heritage Site and a Class I area administered by the National Park Service and is currently suffering impaired visibility and excess nitrogen deposition. We are also concerned that local ozone levels may be harming human health and welfare. We believe that it is becoming increasingly necessary to take all reasonable measures to mitigate the environmental impact of the rapid and substantial energy development taking place in southeastern New Mexico, especially in the vicinity of Carlsbad Caverns NP. It will be far more efficient and cost-effective to take pro-active pollution abatement measures now than retroactively. We appreciate the opportunity to comment on the proposed permit for Lea Power Partners LLC (LPP), located 116 km east of Carlsbad Caverns NP

LPP has submitted a Prevention of Significant Deterioration (PSD) air quality permit application to the Air Quality Bureau (AQB), New Mexico Environment Department (NMED) to modify the Hobbs Generating Station. The proposed modification will consist of improving the station performance by upgrading both gas turbines by replacing the Row 1 Blade Ring and Rows 1 and 2 Turbine Blades and Vanes with new parts that have superior cooling technology. This change will result in the need for less cooling air but will have a corresponding increase in fuel consumption, exhaust flow rate, temperature, and electricity production. This source is a major source according to 20.2.74 NMAC, PSD. The modification is a greenhouse gas only PSD action with a minor increase in annual NO_X emissions.

In its permit application, LPP stated that, "A top down BACT [Best Available Control Technology] determination is provided for the CTG/HRSG air emissions of NO_x, CO, VOC, SO_2, $PM_{10}/PM_{2.5}$, and CO_{2e}." LPP proposes that BACT for NO_X is 2.0 ppm_{vdc}, on a **24-hour average**. We believe that the applicant's BACT analysis for NO_X is defective because it does not consider the "top" level of NO_X control which is 2.0 ppm on a **one-hour average**. We also note that LPP's comment that an appropriate degree for ammonia slip is 7 ppm_{vdc} is not supported by other permitting actions. While LPP cites permits in CA and TX with limits similar to its proposal, we are providing copies of two permits issued by VA (Green Energy and Dominion Warren County) and one permit (El Segundo Power, attached) proposed for issuance by the South Coast Air Quality Management District showing that a more stringent level of NO_X control (i.e., 2.0 ppm on a **one-hour average**) is technically feasible for combined cycle combustion turbines (CCCTs). We also note that permit applications have been submitted for CCCTs at the Bowie Power Station in AZ (attached) and by CPV for its Smyth County (VA) project (application and permit attached) with the same limit (and averaging time). (The Green Energy permit (attached), as well as the El Segundo Power and CPV Smyth County applications also contain 5 ppm ammonia slip limits. We recommend that NMED limit ammonia slip to 5 ppm to reduce resulting visibility impairment and nitrogen deposition.)

Not only is the one-hour averaging time more appropriate for BACT for LLP, it is also consistent with the one-hour averaging period established in the National Ambient Air Quality Standard for NO_2. For the reasons discussed above, we recommend that BACT for NO_X for LPP is 2.0 ppm on a one-hour average.

Finally, we are also concerned about the additional 500,000 tons of greenhouse gases that would be emitted yearly from this project—a discussion of the effects of climate change on arid ecosystems can be found at this link:
http://www.nps.gov/subjects/climatechange/upload/AridLandsTP.pdf

We appreciate the assistance that NMED has provided and we look forward to continuation of those cooperative efforts. Please feel free to contact Don Shepherd (303-969-2075; don_shepherd@nps.gov) with any other questions regarding this project.

Sincerely,

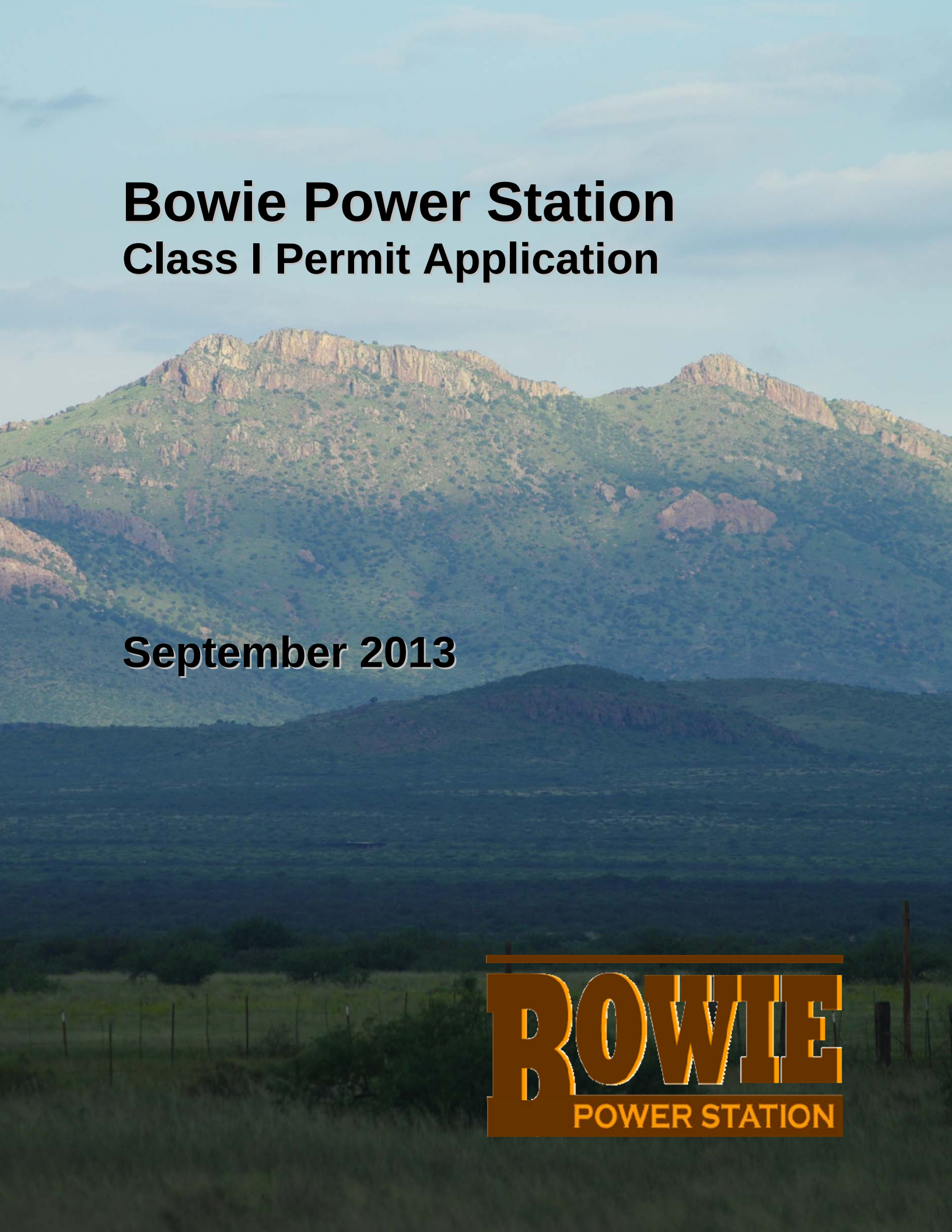
Susan Johnson
Chief, Policy, Planning, and Permit Review Branch

Attachments:

cc:

IMR: Mike George
CAVE: Dennis Velasquez, Kent Schwarzkopf, Luis Florez
ARD-WASO: Julie Thomas McNamee

ARD-DEN: Johnson, McCoy, Vimont, Permit Review Group, Reading and Project File
ARD-DEN: DShepherd:ds:5/23/2014:x2075:Lea Power Partners.Ltr.docx



Bowie Power Station
Class I Permit Application

September 2013

BOWIE
POWER STATION

BOWIE POWER STATION

Class I Permit Application

Applicant:
Bowie Power Station, LLC
3610 N 44th St. Suite 250
Phoenix, AZ 85018

Prepared By:
Wind River Environmental Group LLC
12081 West Alameda Parkway #415
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Prepared for:
Arizona Department of Environmental Quality
Air Quality Division
1110 West Washington Street
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September 2013

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LIST OF ACRONYMS

°F	Degrees Fahrenheit
>	Greater than
$\mu g/m^3$	Micrograms per cubic meter
%	Percent
AAAQS	Arizona Ambient Air Quality Standards
AAAQG	Arizona Ambient Air Quality Guidelines
AAC	Arizona Administrative Code
AADT	Annual average daily traffic
ADEQ	Arizona Department of Environmental Quality
AERMET	AERMOD Meteorological Preprocessor
AERMOD	AMS/EPA Regulatory Model
AMS	American Meteorological Society
AP-42	US Environmental Protection Agency *Compilation of Air Pollutant Emission Factors*
ARM	Ambient Ratio Method
ARS	Arizona Revised Statutes
AQRV	Air quality related values
AZMACT	Arizona Maximum Achievable Control Technology
BAAQMD	Bay Area Air Quality Management District
BACT	Best available control technology
BPIP	Building Profile Input Program
Btu/kWh	British thermal units per kiloWatt hour
Btu/lb	British thermal units per pound
CAA	Clean Air Act
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CCS	Carbon capture and sequestration
CD	Compact disc
CDEP	Connecticut Department of Environmental Protection
CDPF	Catalyzed diesel particulate filters
CEC	California Energy Commission
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Connecticut DEP	Connecticut Department of Environmental Protection
DLN	Dry low NO_x
DOE	U.S. Department of Energy
EAB	Environmental Appeals Board
EOR	Enhanced oil recovery
EPA	US Environmental Protection Agency
EPG	Environmental Planning Group
EPNG	El Paso Natural Gas
ESP	Electrostatic precipitator
FGR	Flue gas recirculation
FLAG	Federal Land Managers' Air Quality Related Values Work Group

LIST OF ACRONYMS (CONTINUED)

FLM	Federal Land Manager
ft	Feet
FWS	US Fish and Wildlife Service
gal/yr	Gallons per year
g/hp-hr	Grams per horse power-hour
g/s	Grams per second
GDNR	Georgia Department of Natural Resources
GE	General Electric
GEP	Good engineering practice
GHG	Greenhouse gas
GVG&N	Gila Valley Globe & Northern Railroad
gpm	Gallons per minute
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HAPRACT	Hazardous air pollutant reasonable available control technology
HHV	Higher heating value
Hp	Horsepower
Hr	Hour
Hr/yr	Hours per year
HRSG	Heat recovery steam generator
ICAC	Institute of Clean Air Companies
IDEM	Indiana Department of Environmental Management
IMPROVE	Interagency Monitoring of Protected Visual Environments
ISA	*Integrated Science Assessment for Carbon Monoxide*
lb/hr	Pounds per hour
ICCR	Industrial Combustion Coordinated Rulemaking
IPCC	Intergovernmental Panel on Climate Change
ISA	Integrated Assessment
ITF	Interagency Task Force
K	Kelvin
KNO_2	Potassium Nitrite
KNO_3	Potassium Nitrate
K_2CO_3	Potassium Carbonate
kg/ha/yr	Kilogram per hectare per year
km	Kilometer
kW	Kilowatt
kV	Kilovolt
LAER	Lowest achievable emission rate
lb/block/event	Pounds per block per event
lb/MMBtu	Pounds per million British thermal units
lb/turbine/event	Pounds per turbine per event
lb/MWh	Pounds per megawatt hour
LDEQ	Louisiana Department of Environmental Quality
LHV	Lower heating value
m	Meter
mi	Mile
m/s	Meters per second

LIST OF ACRONYMS (CONTINUED)

MACT	Maximum achievable control technology
MMBtu	Million British thermal units
MMscf	Million standard cubic feet
msl	Mean sea level
MW	Megawatt
N_2O	Nitrous Oxide
NA	Not applicable/not available
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NAD83	North American Datum 1983
NCDC	National Climate Data Center
NCPA	Northern California Power Agency
NED	National Elevation Dataset
NESCAUM	Northeast States for Coordinated Air Use Management
NETL	National Energy Technology Laboratory
NHPA	National Historic Preservation Act
NIST	National Institute of Standards and Technology
NJDEP	New Jersey Department of Environmental Protection
NLCD	National Land Cover Dataset
NM	National Monument
NMED	New Mexico Environment Department
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
NP	National Park
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
NYDEC	New York Department of Environmental Conservation
O_2	Oxygen
OC	Organic carbon
OCEC	Oregon Clean Energy Center
OEPA	Ohio Environmental Protection Agency
PDEQ	Pima County Department of Environmental Quality
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than 2.5 micrometers
PM_{10}	Particulate matter less than 10 micrometers
POM	Polycyclic organic matter
ppb	Parts per billion
ppm	Parts per million
ppmv	Parts per million by volume
ppmvd	Parts per million by volume dry
ppmw	Parts per million by weight
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
PVMRM	Plume Volume Molar Ratio Method
RACT	Reasonably available control technology

LIST OF ACRONYMS (CONTINUED)

RBLC	RACT/BACT/LAER Clearinghouse
RCRA	Resource Conservation and Recovery Act
RICE	Reciprocating internal combustion engine
scf/hr	Standard cubic feet per hour
SCR	Selective catalytic reduction
SF_6	Sulfur hexafluoride
SIL	Significant impact level
SJVUAPCD	San Joaquin Valley Unified Air Pollution Control District
SMC	Significant monitoring concentration
SMUD	Sacramento Municipal Utility District
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SO_4	Sulfate
tpy	Tons per year
TSS	Technical Support System
US	United States
USGS	US Geological Survey
VDEQ	Virginia Department of Environmental Quality
VOC	Volatile organic compound
WA	Wilderness area
WRAP	Western Regional Air Partnership
WREG	Wind River Environmental Group LLC
yr	Year

1.0 EXECUTIVE SUMMARY

Project Description

Bowie Power Station, LLC proposes to construct and operate a 1,000-megawatt (MW, 1,050 with duct firing) natural gas-fired, combined-cycle combustion turbine facility. The proposed project, called the Bowie Power Station, will be constructed in phases. Phase one will be 525 MW and is addressed in this application. The facility will be located in Cochise County, approximately 2 miles north of the unincorporated community of Bowie. The area is attainment for all pollutants.

Phase I construction is scheduled to begin in mid-2014 and operation is expected to commence in 2017. The facility will be operated 24 hours per day, 7 days per week, 52 weeks per year. The Bowie Power Station will be capable of providing baseload power and is planned as a firming resource for renewable energy production.

Emission Sources

Phase I will include the following primary emission sources:

- Two combined-cycle, natural gas-fired, General Electric (GE) Frame 7FA, Model 4 (7FA.04) combustion turbines with inlet air cooling and two natural gas-fired, duct fired heat recovery steam generators (HRSGs) with a fast start design;
- One natural gas-fired auxiliary boiler;
- One diesel-fired emergency fire pump;
- One cooling tower with nine cells;
- Two evaporation ponds; and,
- Five circuit breakers.

Oxides of nitrogen (NO_x) emissions from the turbines and duct burners will be controlled using selective catalytic reduction (SCR) systems. Carbon monoxide (CO), volatile organic compound (VOC), and organic hazardous air pollutant (HAP) emissions from the turbines and duct burners will be controlled using oxidation catalysts.

Requested Emissions

Annual emissions for the turbines and duct burners have been calculated based on the following operating scenario:

- 4,224 hours per year operation with duct firing and no power augmentation;
- 325 hours per year in startup and tuning;
- 91.25 hours per year in shutdown; and
- Remaining 4,119.75 hours 95% capacity operation with no duct firing.

For some pollutants, turbine emissions vary based on ambient temperatures. Annual emissions have been calculated assuming a conservative average ambient temperature of 59 degrees Fahrenheit (°F). SCR and oxidation catalyst control of emissions were included in the turbine and duct burner emission estimates.

Cooling tower annual emissions were based on a capacity factor of 100%, tower flow rate, total dissolved solids in the circulating water, and the expected performance of drift eliminators. Auxiliary

boiler annual emissions were calculated based on 450 hours of operation per year at full load. Emergency fire pump annual emissions were estimated based on 120 hours of operation at full load.

Total project emissions for criteria pollutants and greenhouse gases (GHG) (tons per year [tpy]) are shown in Table 1-1. Emissions of HAPs are shown in Table 1-2.

Table 1-1. Project Annual Criteria and Greenhouse Gas Pollutant Emissions

Pollutant	Emissions (tons per year)
NO_x (as NO_2)	139.4
CO	161.5
VOCs	30.6
SO_2	30.0
PM	68.3
PM_{10}	66.5
$PM_{2.5}$	64.5
Lead	0.0009
CO_2	1,752,382.4
CH_4	33.0
N_2O	3.3
SF_6	0.0009
CO_2e	1,754,122.1

Notes:

CO	=	Carbon monoxide	PM	=	Particulate matter
CO_2	=	Carbon dioxide	PM_{10}	=	Particulate matter less than 10 micrometers
CO_2e	=	Carbon dioxide equivalent	$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
CH_4	=	Methane	SF_6	=	Sulfur hexafluoride
N_2O	=	Nitrous Oxide	SO_2	=	Sulfur dioxide
NO_x	=	Oxides of nitrogen	tpy	=	Tons per year
NO_2	=	Nitrogen dioxide	VOC	=	Volatile organic compound

Regulatory Requirements

The Bowie Power Station will have a potential to emit over 100 tpy of NO_x and CO and will be a major source. The project will be located in an attainment area for all pollutants. The project will not be a major source of HAPs.

The project is subject to the permitting provisions in Arizona Department of Environmental Quality (ADEQ), Code of Regulations and must meet the Class I permitting requirements in Arizona Administrative Code (AAC), Title 18, Chapter 2, Article 3 and the new major source permitting requirements in Article 4. An Acid Rain Permit must be obtained in accordance with AAC Title 18, Chapter 2, Article 3.

The project is subject to emission limits as shown in Table 1-3:

Best Available Control Technology

The project must adopt best available control technology (BACT) for control of NO_x, CO, particulate matter (PM), particulate matter less than 10 micrometers in diameter (PM_{10}), and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). The results of the BACT analyses are shown in Table 1-4.

Table 1-2. Project Annual Federal Hazardous Air Pollutant Emissions

Pollutant	Emissions (tpy)
Acetaldehyde	0.2
Acrolein	0.03
Antimony	0.00005
Arsenic	0.0004
Benzene	0.06
Beryllium	0.00001
Cadmium	0.002
Chloroform	0.65
Chromium	0.003
Cobalt	0.0001
Dichlorobenzene	0.0006
Ethylbenzene	0.16
Formaldehyde	3.56
Hexane	0.95
Lead	0.0009
Manganese	0.0007
Mercury	0.0005
Naphthalene	0.007
Nickel	0.004
Polycyclic Organic Matter (POMs)	0.01
Selenium	0.00005
Toluene	0.65
Xylenes	0.32
Total Federal HAPs	6.59

Notes:

HAPs = Hazardous air pollutants
tpy = Tons per year

Table 1-3. Regulatory Emission Limits

Regulatory Citation	Emission Limit
R18-2-702(B)	Auxiliary Boiler, Emergency Fire Pump, Cooling Tower: 40% opacity
R18-2-724(C)(1)	Auxiliary boiler: PM emissions lb/hr = 1.02 x (heat input)$^{0.769}$
40 CFR 60, Subpart IIII, 60.4205(c) and 40 CFR 63, Subpart ZZZZ, 63.6590(c)	Emergency Fire Pump Engine: Purchase engine certified to meet the emission limits in Table 4 to 40 CFR 60, Subpart IIII NO_x+NMHC: 3.0 g/hp-hr; CO: 2.6 g/hp-hr; PM: 0.15 g/hp-hr; ultra-low sulfur fuel
40 CFR 60, Subpart KKKK, 60.4320	Turbines: NO_x Emissions 15 ppm at 15% oxygen or 1.2 lb/MWh
40 CFR 60, Subpart KKKK, 60.4330	Turbines: SO_2 Emissions 0.90 lb/MWh or use fuel with a total potential SO_2 emission potential less than 0.060 lb/MMBtu

Notes:

% = Percent
CFR = Code of Federal Regulations
lb/MMBtu = Pounds per million British thermal units
NMHC = Non-methane hydrocarbons
PM = Particulate matter
SO_2 = Sulfur dioxide
CO = Carbon monoxide
lb/hr = Pounds per hour
lb/MWh = Pounds per megawatt hour
NO_x = Oxides of nitrogen
ppm = Parts per million

Table 1-4. Results of BACT Analyses

Emission Unit	Pollutant	Control Measure(s)	Proposed Emission Limit(s)
Turbines and Duct Burners[a]	NO_x – Normal Operation	DLN and SCR	2.0 ppmv at 15% O_2, 1-hour average
	CO – Normal Operation	Oxidation Catalyst	2.0 ppmv at 15% O_2, 1-hour average
	PM, PM_{10}, $PM_{2.5}$ – Normal Operation	Natural Gas	8.5 lb/hr
	NO_x and CO – Startup/Shutdown/Tuning	Fast Start Design and Work Practices	Hot Start NO_x (as NO_2) – 50.7 lb/turbine/event CO – 131.1 lb/turbine/event Warm Start: NO_x (as NO_2) – 78.9 lb/turbine/event CO – 145.0 lb/turbine/event Cold Start: NO_x (as NO_2) – 78.9 lb/turbine/event CO - 145.0 lb/turbine/event Tuning: NO_x (as NO_2) – 78.9 lb/turbine/hour CO - 145.0 lb/turbine/hour Shutdown: NO_x (as NO_2) – 16.4 lb/turbine/event CO – 51.5 lb/turbine/event
	GHG	Efficient Electricity Production	CO_2e – 1,752,769.1 tpy (two turbines and two duct burners combined)
Auxiliary Boiler	NO_x (as NO_2)	Low NO_x Burners	0.036 lb/MMBtu
	CO	Good Combustion Practices	0.037 lb/MMBtu
	PM, PM_{10}, $PM_{2.5}$	Low Sulfur Fuel	0.007 lb/MMBtu
	GHG	Limited Operation and Boiler Efficiency	CO_2e – 1,316.5 tpy
Emergency Fire Pump	NO_x (as NO_2)	Combustion Control Limited Operation	2.20 g/hp-hr
	CO	Combustion Control Limited Operation	1.42 g/hp-hr
	PM, PM_{10}, $PM_{2.5}$	Low Sulfur Fuel Limited Operation	0.12 g/hp-hr
	GHG	--	CO_2e – 15.0 tpy
Cooling Tower	PM, PM_{10}, $PM_{2.5}$	Wet Cooling with Drift Eliminators	PM: 1.3 lb/hr PM_{10}: 0.9 lb/hr $PM_{2.5}$: 0.4 lb/hr
Circuit Breakers	GHG	Leak Detection Monitoring	Alert at 10% Loss

[a] Emission limits shown are for each turbine and duct burner pair except for GHG.

Notes:

CO	=	Carbon monoxide	CO_2e	=	Carbon dioxide equivalent
DLN	=	Dry low NO_x Combustion	GHG	=	Greenhouse gases
g/hp-hr	=	Grams per horsepower hour	lb/turbine/event	=	Pounds per turbine per event
lb/hr	=	Pounds per hour	lb/MMBtu	=	Pounds per million British thermal units
NO_x	=	Oxides of nitrogen	NO_2	=	Nitrogen dioxide
PM_{10}	=	Particulate matter less than 10 micrometers	$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
PM	=	Particulate matter	ppmv	=	Parts per million by volume
O_2	=	Oxygen	SCR	=	Selective catalytic reduction
tpy	=	Tons per year			

Impact on Ambient Air Quality

Modeling of estimated criteria pollutant impacts has demonstrated that National and ARizona Ambient Air Quality Standards (NAAQS/AAAQS) and allowable Prevention of Significant Deterioration (PSD) increments will not be violated. Modeling results are shown in Table 1-5.

Table 1-5. Air Quality Impacts

Averaging Period/ Pollutant	Bowie Power Station Maximum Predicted Class II Impact ($\mu g/m^3$)	Class II Modeling Significance Level ($\mu g/m^3$)	Significant Monitoring Level ($\mu g/m^3$)	Limiting NAAQS/AAAQS ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	Bowie Power Station Maximum Predicted Class I Impact ($\mu g/m^3$)	Class I Modeling Significance Level ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
1-hour NO_2	192.3 (high, 8th high) (includes background and nearby source contributions)[a]	7.5	NA	188.7	NA	NA	NA	NA
Annual NO_2	0.27	1	14	100	25	0.01	0.1	2.5
1-hour SO_2	5.1	8	NA	196.4	NA	NA	NA	NA
3-hour SO_2	1.8	25	NA	1,300	512	NA	1.0	25
24-hour SO_2	0.35	5	NA	365	91	NA	0.2	5
Annual SO_2	0.06	1	NA	80	20	NA	0.1	2
24-hour PM_{10}	1.8	5	10	150	30	0.08	0.3	8
Annual PM_{10}	0.26	1	NA	50	17	0.002	0.2	4
24-hour $PM_{2.5}$	1.1	1.2	NA	35	9	0.01	0.07	2
Annual $PM_{2.5}$	0.16	0.3	NA	12	4	0.001	0.06	1
1-hour CO	439	2,000	NA	40,000	NA	NA	NA	NA
8-hour CO	85	500	575	10,000	NA	NA	NA	NA

[a] Approximately 88% of total impact is due to Apache Generating Station emissions; Bowie Power Station contribution is 0.0002%.

Notes:

Concentrations shown are the maximum predicted, 1st high concentrations, unless otherwise noted.

$\mu g/m^3$	=	Micrograms per cubic meter	AAAQS	=	Arizona Ambient Air Quality Standards
CO	=	Carbon monoxide	NA	=	Not applicable
NAAQS	=	National Ambient Air Quality Standards	NO_2	=	Nitrogen dioxide
PM_{10}	=	Particulate matter less than 10 micrometers	$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
PSD	=	Prevention of Significant Deterioration	SO_2	=	Sulfur dioxide

2.0 PROJECT DESCRIPTION

Bowie Power Station, LLC proposes to construct and operate a 1,000-megawatt (MW, 1,050 with duct firing) natural gas-fired, combined-cycle combustion turbine facility. The proposed project, called the Bowie Power Station, will be constructed in phases. Phase one will be 500 MW (525 MW with duct firing) and is addressed in this application. The facility will be located in Cochise County, approximately 2 miles north of the unincorporated community of Bowie. The site location is shown in Figure 2-1. The area is attainment for all pollutants. A site plan showing equipment layout is provided as Figure 2-2.

Construction is scheduled to begin in mid-2014 and operation is expected to commence in 2017. The facility will be operated 24 hours per day, 7 days per week, 52 weeks per year. The Bowie Power Station will be capable of providing baseload power and is planned as a firming resource for renewable energy production. Key project information is summarized in Table 2-1.

Table 2-1. Project Information

Data Element	Project-Specific Information
Facility Type	Combined-cycle combustion turbine
Product	Electricity
Raw Materials	Natural gas, water
Phase Size	525 megawatt total
Phase Construction Start Date	Mid-2014
Phase Operation Commencement Date	2017
Project Location	Section 28, Township 12 South, Range 28 East
Operation Schedule	24 hours/day, 7 days/week, 52 weeks/year

Phase I will include the following primary emission sources:

- Two combined-cycle, natural gas-fired, General Electric (GE) Frame 7FA, Model 4 (7FA.04) combustion turbines with inlet air cooling and two natural gas-fired, duct fired heat recovery steam generators (HRSGs) with a fast start design;
- One natural gas-fired auxiliary boiler;
- One diesel-fired emergency fire pump;
- One nine-cell cooling tower;
- Two evaporation ponds; and
- Five circuit breakers.

Two evaporation ponds will be constructed; however, each pond individually has the required capacity for the initial power block addressed by this application. The combined capacity will be required when a second power block is constructed.

A permit application form and equipment list are included in Appendix A. Raw materials used to produce electricity are natural gas and water. The combustion turbines will be equipped with dry low NO_x (DLN) combustors. Selective catalytic reduction (SCR) systems will be used to control oxides of nitrogen (NO_x) and oxidation catalysts will be used to control carbon monoxide (CO) from the turbines and duct burners. Volatile organic compounds (VOCs) and organic hazardous air pollutants (HAPs) from the turbines and duct burners will also be controlled by the oxidation catalysts. The SCR systems will use industrial grade aqueous ammonia (approximately 19% ammonia).

The power block will consist of the two combustion turbines with inlet air cooling, two HRSGs equipped with duct firing, and one steam turbine electric generator. The power block will have a fast start design. A process flow diagram illustrating the generating unit configuration is provided in Figure 2-4.

Each turbine in a generating unit will exhaust through a HRSG. Each HRSG will be equipped with a duct firing system. Steam from two HRSGs will be directed to the steam turbine electric generator. The power blocks with have a fast start design. Exhaust from each HRSG will exit through a stack dedicated to that turbine and HRSG.

2.1 Project Equipment

Information on the following equipment is provided in this section:

- Two combined-cycle, natural gas-fired, GE Frame 7FA, Model 4 (7FA.04) combustion turbines with inlet air cooling and two natural gas-fired, duct fired HRSGs with a fast start design;
- One natural gas-fired auxiliary boiler;
- One diesel-fired emergency fire pump;
- One nine-cell cooling tower; and
- Five circuit breakers.

Detailed information on the combustion turbines and duct burners is provided in Table 2-2.

Auxiliary fuel-burning equipment at the site will include a natural gas-fired auxiliary boiler and a diesel-fired emergency fire pump. The auxiliary boiler will be equipped with low NO_x burners to minimize NO_x emissions. Boiler information is provided in Table 2-3 and fire pump information is provided in Table 2-4.

The plant will use a mechanical draft cooling tower. Information on the cooling tower is presented in Table 2-5.

There will be an electrical switchyard within the Bowie Power Station boundary. The switchyard will include five, 345 kilovolt (kV) circuit breakers each containing 360 pounds of sulfur hexafluoride (SF_6), a greenhouse gas (GHG). The circuit breakers located on the Bowie Power Station site will have the potential for fugitive emissions of SF_6 as a result of equipment leaks. Information on the circuit breaker is summarized in Table 2-6.

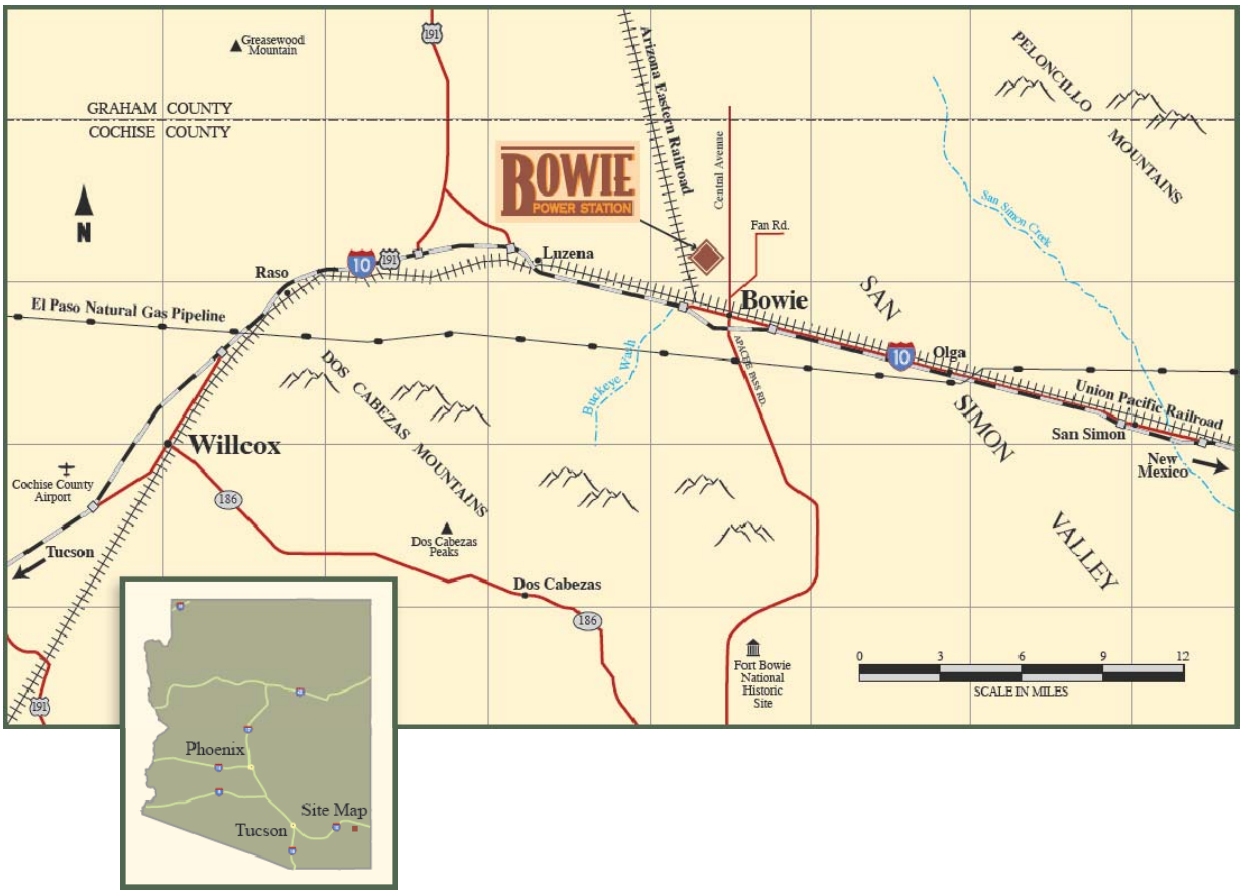

Figure 2-1. Bowie Power Station Location

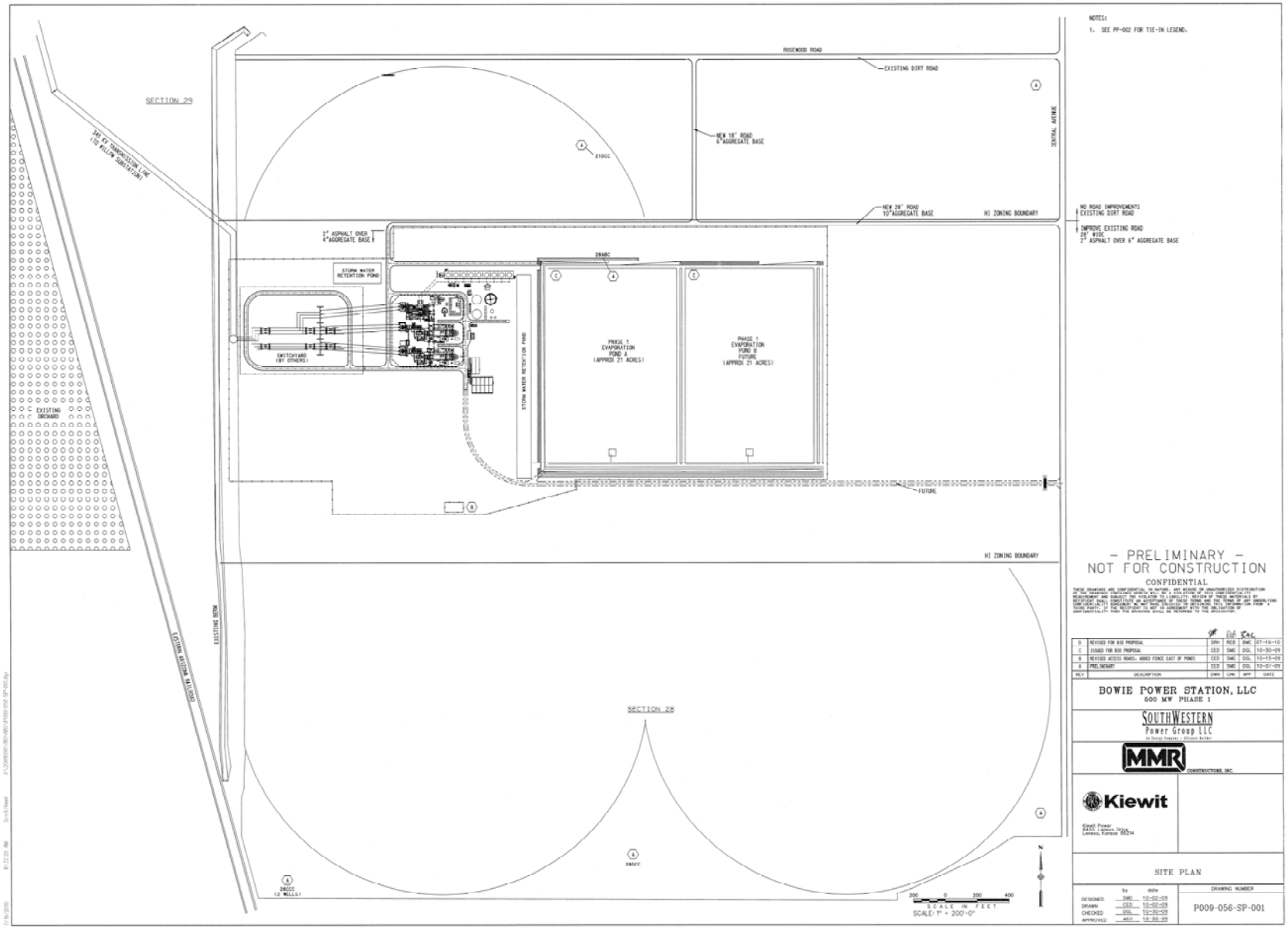

Figure 2-2. Bowie Power Station Site Plan

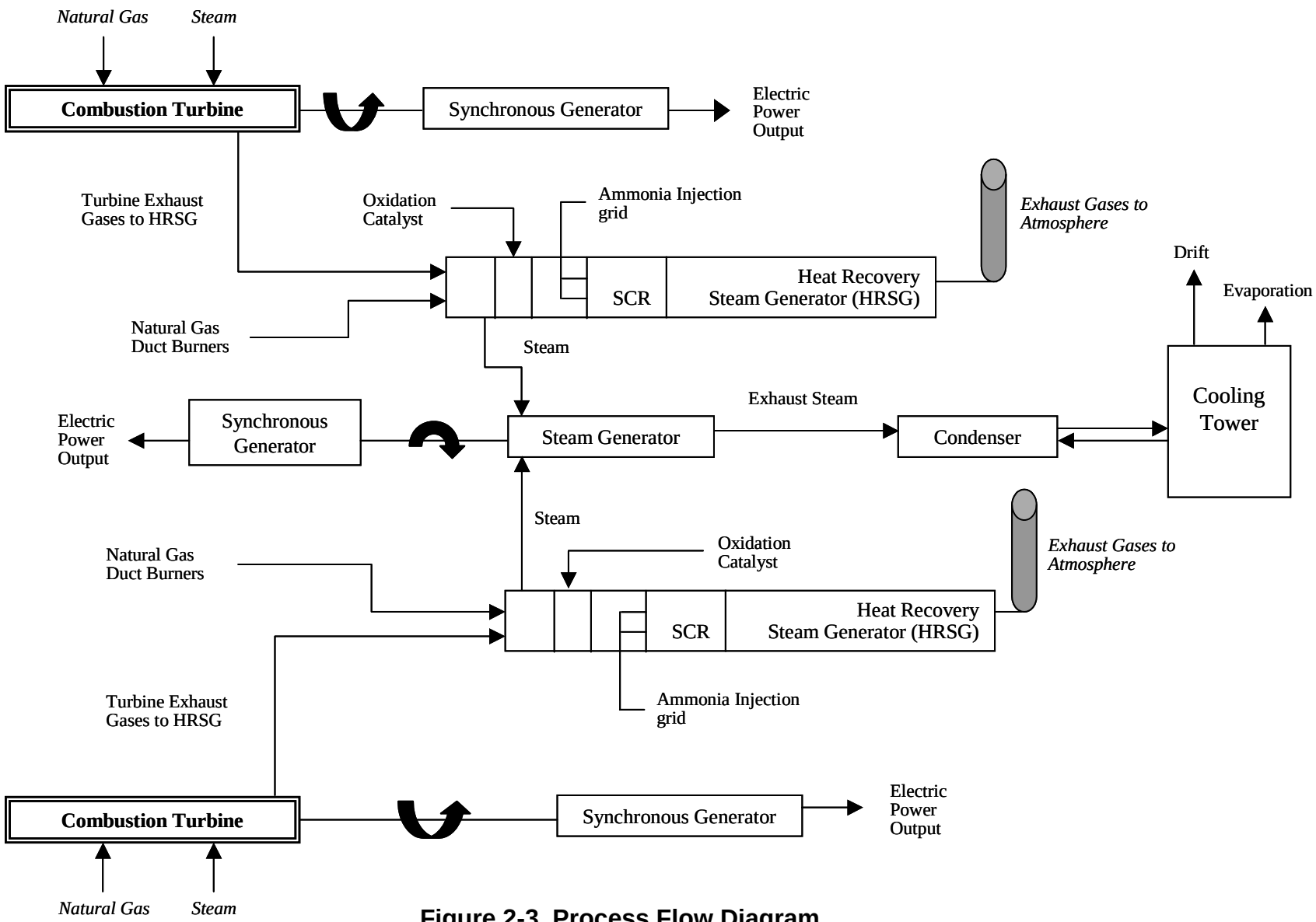

Figure 2-3. Process Flow Diagram

Table 2-2. Turbine and Duct Burner Information

Parameter	Project Information
Source Classification Code	20100201
Number	2
Turbine Manufacturer	General Electric
Turbine Model Number	Frame 7FA, Model 4
Fuel	Natural gas Backup fuel – none
Pollution Prevention	Dry Low NO_x (DLN) combustion systems
Startup Capability	Fast start design
Generating Capacity	172 MW (nominal) each combustion turbine
Maximum Hourly Heat Input Rate (Maximum Hourly Process Rate)[a]	Turbines (each): 1,734.6 MMBtu/hr (HHV)[a] 1,829.6 gigajoules/hr (HHV) Duct burners (each): 420 MMBtu/hr (HHV)
Maximum Annual Heat Input (Maximum Annual Process Rate)	Turbines (two): 28,870,017 MMBtu/yr (HHV) Duct burners (two): 3,548,160 MMBtu/yr (HHV)
Operating Parameters	Turbines: 95% capacity factor Normal turbine operation between minimum compliance load (load at which DLN system can achieve an oxides of nitrogen concentration of 9 parts per million by volume dry at 15% oxygen) and 100% load: 3681.75 hours per year per turbine Duct burners: 4,224 hours per year per turbine Startup/Tuning mode: 325 hours per year per turbine Shutdown mode: 91.25 hours per year per turbine Hot start: Downtime less than 8 hours, duration 0.5 hours Warm start: Downtime between 8 hours and 72 hours, duration 1 hour. Cold start: Downtime 72 hours or greater, duration 1 hour
Control Technologies	Selective catalytic reduction systems NO_x control: 2.0 ppmv at 15% O_2 Oxidation catalysts CO control: 2.0 ppmv at 15% O_2

[a] Heat input rate varies with load and ambient temperature. Maximum heat input rate is shown.

Notes:

%	=	Percent
CO	=	Carbon monoxide
HHV	=	Higher heating value
hr	=	Hour
MMBtu	=	Million British thermal units
MW	=	Megawatt
NO_x	=	Oxides of nitrogen
O_2	=	Oxygen
ppmv	=	Parts per million by volume
yr	=	Year

Table 2-3. Auxiliary Boiler Information

Parameter	Project Information
Source Classification Code	10200602
Number	1
Size	50 MMBtu/hr
Fuel	Natural gas
Maximum Hourly Fuel Input (Maximum Hourly Process Rate)	48,328 scf/hr
Maximum Annual Fuel Input (Maximum Annual Process Rate)	21.8 MMscf/yr
Operating Parameters	450 hr/yr
Control Technology	Low NO_x burners with flue gas recirculation

Notes:

hr	=	Hour
MMBtu	=	Million British thermal units
MMscf	=	Million standard cubic feet
NO_x	=	Oxides of nitrogen
scf	=	Standard cubic feet
yr	=	Year

Table 2-4. Emergency Fire Pump Information

Parameter	Project Information
Source Classification Code	20200102
Equipment Type	Internal combustion engines
Number	1
Size	260 horsepower; 1.8 MMBtu/hr
Fuel	Diesel fuel
	Diesel sulfur content – 0.0015% by weight
	Diesel heat content – 137,000 Btu/gallon
Maximum Hourly Fuel Input	13.4 gallons/hr
Maximum Annual Fuel Input	1,340 gallons/yr
Operating Parameters	100 hr/yr

Notes:

%	=	Percent
Btu	=	British thermal units
hr	=	Hour
MMBtu	=	Million British thermal units
yr	=	Year

Table 2-5. Cooling Tower Information

Parameter	Project Information
Source Classification Code	A2820000000
Number	1
Number of Cells per Tower	9
Control Technology	Drift eliminators
Circulating Rate	127,860 gpm
Total Dissolved Solids	4,039 ppmw
Drift Rate	0.0005% of flowrate
Operating Parameters	100% capacity factor

Notes:

%	=	Percent
gpm	=	Gallons per minute
ppmw	=	Parts per million by weight

Table 2-6. Circuit Breaker Information

Parameter	Project Information
Source Classification Code	None
Number	5
Size	345 kilovolt each
Sulfur Hexafluoride Content	360 pounds each

2.2 Project Emissions

This section discusses emission estimates for each type of emission source and presents total project emissions for both criteria pollutants and HAPs.

2.2.1 Turbine and Duct Burner Emissions

The engineering firm hired to design the facility, Kiewit Power Engineers Co. (Kiewit), provided criteria pollutant hourly emission rates for the combustion turbines and duct burners (except for particulate matter [PM], particulate matter with an aerodynamic equivalent diameter less than or equal to 10 micrometers [PM_{10}], and particulate matter with an aerodynamic equivalent diameter less than or equal to 2.5 micrometers [$PM_{2.5}$]). Turbine PM emissions were based on source testing of similar combined-cycle turbines and the results of the best available control technology (BACT) analysis. It has been assumed that all particulate matter emissions from the turbines and duct burners are $PM_{2.5}$. This means that the emission rates for PM, PM_{10}, and $PM_{2.5}$ are the same for the turbines and duct burners.

Load and ambient temperature affect turbine and duct burner NO_x, CO, VOC, and sulfur dioxide (SO_2) emissions. Annual turbine and duct burner emissions for these pollutants were calculated based on a conservative average annual ambient temperature of 59 degrees Fahrenheit (°F). The turbine and duct burner annual emission calculations for these pollutants include 4,224 hours of operation for the duct burners, 325 hours per year of startup and tuning operation, and 91.25 hours of shutdown operation.

The turbines will be equipped with low NO_x combustors that are designed to emit 9 parts per million by volume (ppmv) NO_x. SCR control of NO_x emissions will further reduce turbine and duct burner emissions to 2.0 ppmv at 15% oxygen (O_2). Oxidation catalysts will be used to reduce turbine and duct burner emissions of CO. The oxidation catalysts will also control emissions of VOCs and organic HAPs.

Turbine emission rates for NO_x, CO, and VOCs are higher during startup, shutdown and tuning than during normal operation. One factor that influences emissions is the time it takes for the turbine system to start up. Turbine manufacturers, engineering, and energy companies have developed turbine system designs that allow for faster startups. These use different steam drum designs that allow faster startups. In addition, fast start designs decouple the combustion turbine from the steam turbine during the early stages of the startup process, minimizing low load, higher emission combustion turbine operation. A fast start design developed by Kiewit will be used for the Bowie Power Station to allow for faster startups and to minimize startup emissions. Startup and shutdown emission estimates have been provided by Kiewit.

Turbine and duct burner HAP emissions were estimated based on emission factors presented in the US Environmental Protection Agency's (EPA's) *Compilation of Air Pollutant Emission Factors* (AP-42; EPA 2013a). GHG emissions have been calculated using emission factors from 40 Code of Federal Regulations (CFR) Part 98 and converted to carbon dioxide (CO_2) equivalent (CO_2e) emissions by multiplying each pollutant's emissions by its global warming potential, as listed in Table A-1 of 40 CFR 98, Subpart A.

Emission calculations are provided in Appendix B.

2.2.2 Auxiliary Boiler Emissions

The turbine system fast start design requires an auxiliary boiler. Auxiliary boiler criteria pollutant and HAP emissions from natural gas combustion were calculated based on manufacturer's data and emission factors from AP-42, Section 1.4 and 40 CFR 98. Annual emissions were calculated based on 450 hours of operation per year. Emission calculations are provided in Appendix B.

2.2.3 Emergency Fire Pump Emissions

Emergency fire pump criteria pollutant emissions from diesel fuel combustion were calculated based on manufacturer's data and emission factors from AP-42, Section 3.4 and 40 CFR 98. Annual emissions were calculated based on 100 hours of operation per year. Emission calculations are provided in Appendix B.

2.2.4 Cooling Tower and Evaporation Pond Emissions

Cooling tower PM, PM_{10} and $PM_{2.5}$ emissions were calculated based on the total dissolved solids in the circulating water and the expected performance of the drift eliminators as provided by the manufacturer. Emissions of PM_{10} and $PM_{2.5}$ were based on a particle size distribution calculated following the method presented in an article from the July 2002 issue of *Environmental Progress* titled "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie and using the droplet size distribution provided by the cooling tower manufacturer.

HAP emissions were calculated based on the cooling tower drift rate and the chemical composition of the cooling tower blowdown. It was conservatively assumed that the entire quantity of each chemical in the blowdown would be emitted. Chloroform emissions for the cooling towers and evaporation ponds were based on factors from EPA's *Locating and Estimating Air Emissions from Sources of Chloroform* (EPA 1984). Although the evaporation ponds have the capacity to accommodate the cooling water from two power blocks, emissions from the evaporation ponds were calculated based on cooling water from the initial power block only.

Annual emissions of $PM/PM_{10}/PM_{2.5}$ and HAPs from the cooling towers were calculated assuming a 100% capacity factor. Emission calculations are provided in Appendix B.

2.2.5 Circuit Breaker Emissions

Circuit breaker SF_6 emissions were calculated based on a leak rate of 0.1% per year. SF_6 emissions were converted to CO_2e using the global warming potential in 40 CFR 98, Subpart A, Table A-1

2.2.6 Project Total Emissions

Total project annual emissions are summarized in Tables 2-7 and 2-8. Criteria pollutants and GHG emissions are compared to the Prevention of Significant Deterioration (PSD) significance levels. Emissions are for two turbines, an auxiliary boiler, an emergency fire pump, one cooling tower, two evaporation ponds, and five circuit breakers. As shown in Table 2-7, the project is a PSD major source (emissions greater than 100 tons per year [tpy]) for NO_x and CO. PSD applies to GHG emissions from the project. The project is a minor HAP source with total HAP emissions less than 25 tpy and emissions of each individual HAP less than 10 tpy.

Table 2-7. Project Criteria Pollutant Annual Emissions Summary

Pollutant	PSD Significance Level (tpy)	Annual Emissions (tpy)
Oxides of nitrogen (as nitrogen dioxide)	40	139.4
Carbon monoxide	100	161.5
Volatile organic compounds	40	30.6
Sulfur dioxide	40	30.0
Particulate matter	25	68.3
PM_{10}	15	66.5
$PM_{2.5}$	10	64.5
Lead	0.6	0.001
Fluorides	3	Negligible emissions
Sulfuric acid mist	7	Negligible emissions
Total reduced sulfur	10	Negligible emissions
Reduced sulfur compounds	10	Negligible emissions
Carbon dioxide	--	1,752,382.4
Methane	--	33.0
Nitrous Oxide	--	3.3
Sulfur hexafluoride	--	0.0009
Carbon dioxide equivalent	75,000[a]	1,754,122.1

[a] Threshold for sources subject to PSD for another pollutant.

Notes:

PM_{10}	=	Particulate matter less than 10 micrometers
$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
PSD	=	Prevention of significant deterioration
tpy	=	Tons per year

Table 2-8. Project Hazardous Air Pollutant Annual Emissions Summary

Pollutant	Annual Emissions (tpy)
Acetaldehyde	0.2
Acrolein	0.03
Antimony	0.00005
Arsenic	0.0004
Benzene	0.06
Beryllium	0.00001
Cadmium	0.002
Chloroform	0.65
Chromium	0.003
Cobalt	0.0001
Dichlorobenzene	0.0006
Ethylbenzene	0.16
Formaldehyde	3.56
Hexane	0.95
Lead	0.0009
Manganese	0.0007
Mercury	0.0005
Naphthalene	0.007
Nickel	0.004
Polycyclic Organic Matter (POMs)	0.01
Selenium	0.00005
Toluene	0.65
Xylene	0.32
Total Federal HAPs	6.59

Notes

HAPs = Hazardous air pollutants
tpy = Tons per year

3.0 REGULATORY REVIEW

This section provides a regulatory review for the Bowie Power Station. Section 3.1 addresses permitting requirements and Section 3.2 addresses emission limits and associated monitoring requirements. Section 3.3 addresses federal greenhouse gas (GHG) requirements. Section 3.4 addresses US Fish and Wildlife Service (FWS) requirements and Section 3.5 addresses the National Historic Preservation Act (NHPA).

3.1 Permitting Requirements

This subsection provides information on the permitting requirements applicable to the Bowie Power Station.

3.1.1 Class I Permitting Requirements

The Arizona Administrative Code (AAC), Title 18, Chapter 2, Article 3 [R18-2-302(B)(1)] requires that a Class I permit be obtained prior to commencing construction of a major stationary source. For purposes of Article 3, a major stationary source is defined in R18-2-101(64)(C) as a source with the potential to emit 100 tons per year (tpy) or more of any air pollutant. The Bowie Power Station, as shown in Table 2-7, will have the potential to emit over 100 tpy of oxides of nitrogen (NO_x) and carbon monoxide (CO). The project will be a major source and a Class I permit must be obtained prior to construction.

A primary Class I permit application requirement is a listing of applicable requirements and associated compliance methods. This listing is provided in Appendix C. A list of insignificant activities that are exempt because of size must be provided and is also included in Appendix C. Finally, Section R18-2-325(A) allows the Director to provide a permit shield by including "determinations that other requirements specifically identified are not applicable." A permit shield is requested for the Bowie Power Station and a listing of requirements that are not applicable is provided in Appendix C.

3.1.2 New Major Source Permitting Requirements

Article 4 [R18-2-402(A)] of AAC, Title 18, Chapter 2 also requires that a permit be obtained prior to commencing construction of a new major source of air pollution. The Article 4 definition of a major stationary source in an attainment area is found in Section R18-2-401(9)(b). A major source in an attainment area is defined as a categorical source with the potential to emit 100 tpy or more of any conventional air pollutant. Categorical sources are defined in R18-2-401(2) and include "fossil fuel-fired steam electric plants and combined-cycle gas turbines of more than 250 million Btu's per hour heat input." The Bowie Power Station will be a categorical source and, as shown in Table 2-7, will have the potential to emit over 100 tpy of NO_x and CO. The Bowie Power Station is an Article 4 major source and the requirements of Section R18-2-402 must be met.

Section R18-2-402(B) contains requirements for all Article 4 permit applications. Section R18-2-406 contains the permit requirements applicable to new major sources located in attainment areas. The Bowie Power Station will be located in an area that is attainment for all pollutants and the requirements of Section R18-2-406, as well as those of Section R18-2-402(B), apply. The permitting requirements of Article 4 are summarized in Table 3-1.

3.1.3 Other Permitting Requirements

Two other types of permitting requirements were reviewed for this project. First, the requirements associated with the Acid Rain Program were reviewed. Second, the requirements associated with hazardous air pollutants (HAPs) were reviewed.

Table 3-1. New Major Source Permitting Requirements

Regulatory Citation	Requirement, Applicability, and Compliance
R18-2-402.A	**Requirement:** Obtain permit prior to commencing construction of a new major source.
	Applicability: Construction of a new major source.
	Project: Project is a new major source.
	Compliance: This application is being submitted to obtain the required permit.
R18-2-402.B	**Requirement:** The application must demonstrate: ▸ An air quality impact analysis that initially considered only the geographical area located within a 50 kilometer radius from the point of greatest emissions from the new source has been conducted. ▸ The more stringent of the applicable new source performance standards in Article 9 of Chapter 2 or the existing source performance standards in Article 7 of Chapter 2 are applied. ▸ The visibility requirements contained in R18-2-410 are satisfied. ▸ All applicable provisions of Article 3 of Chapter 2 are met. ▸ Applicable emission limitations, design, equipment, work practice, and operational standards, or combination thereof, will be complied with. ▸ No applicable standards for hazardous air pollutants will be exceeded. ▸ No limitations on emissions from nonpoint sources contained in Article 6 will be exceeded. ▸ The ambient air quality standard for lead in R18-2-206 will not be violated, if the source will emit 5 tons per year or more of lead. ▸ No adverse impact on visibility, as determined according to R18-2-410, will occur.
	Applicability: New major sources.
	Project: Project is a new major source.
	Compliance: ▸ The air quality impact analysis for the project is described in Section 5 of this application. It has been conducted in accordance with a modeling protocol reviewed and approved by the Arizona Department of Environmental Quality. ▸ Compliance with performance standards and emission limitations is addressed for the project in Table 3-2 of this application. ▸ The analysis associated with visibility protection standards required in R18-2-410 for the project is provided in Section 5 of this application. ▸ Requirements of Article 3 are addressed in Appendix C. ▸ Emission limitations, design, equipment, work practice, and operational standards applicable to the project are addressed in Table 3-2 and Appendix C of this application. ▸ 40 CFR 63, Subpart ZZZZ regulates hazardous air pollutant emissions from the emergency fire pump. Subpart ZZZZ requirements will be met. ▸ Article 6 limitations are addressed in the applicable requirements table in Appendix C. ▸ Project will NOT emit 5 tons per year or more of lead. ▸ Visibility impacts are addressed in Section 5 of this application.

Table 3-1. (Continued)

Regulatory Citation	Requirement, Applicability, and Compliance
R18-2-406	**Requirement:** Meet the following conditions: [a] ▸ Apply BACT for each pollutant listed in R18-2-101(104)(a) for which the potential to emit is significant. ▸ Perform an ambient air quality impact analysis and monitoring as specified in R18-2-407. The analysis must demonstrate that the allowable emission increases from the new major source, in conjunction with all other applicable emission increases or reductions, would not: - Cause or contribute to an increase in concentrations of any pollutant by an amount in excess of the allowed increments; or - Contribute to a significant increase in concentrations for a pollutant in an adjacent nonattainment area.
	Applicability: ▸ Project must be major. ▸ Project must be located in an attainment area.
	Project: ▸ The project is a new major source. ▸ The project will be located in an area that is attainment for all pollutants.
	Compliance: ▸ BACT analyses for the project are presented in Section 4 of this application. BACT will be applied. ▸ Ambient air quality impact analyses demonstrating compliance for the project are presented in Section 5 of this application.
R18-2-407	**Requirement:** Provide in the permit application: ▸ Analysis of ambient air quality in the area that the new major source would affect for each pollutant that would be emitted in significant amount. ▸ Continuous air quality monitoring data, if the emission increase of the pollutant from the new source is above specified amounts. ▸ An analysis of the impairment to visibility, soils, and vegetation that would occur as the result of general commercial, residential, industrial, and other growth associated with the new source. ▸ An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the new source.
	Applicability: ▸ Project must be major. ▸ Project must be located in an attainment area.
	Project: ▸ The project is a new major source. ▸ The project will be located in an area that is attainment for all pollutants.
	Compliance: ▸ Ambient air quality impact analysis is presented in Section 5 of this application. ▸ Required monitoring data are discussed in Section 5 of this application. ▸ Analyses of the impacts to visibility, soils, and vegetation are presented in Section 5 of this application. ▸ Growth analysis is provided in Section 5 of this application.

Table 3-1. (Continued)

Regulatory Citation	Requirement, Applicability, and Compliance
R18-2-410	**Requirement:** Provide: ▸ An analysis of the anticipated impacts on visibility in any Class I areas. ▸ Results of monitoring of visibility in any area near the proposed source.
	Applicability: ▸ Project must be new source. ▸ Project must be major.
	Project: ▸ The project is a new major source.
	Compliance: ▸ Visibility impacts associated with the project are discussed in Section 5 of this application.
R18-2-333(A) 40 CFR 72.30(b)(2)(ii)	**Requirement:** Twenty-four months before the unit is to commence operation, a complete acid rain permit application (including compliance plan) must be filed.
	Applicability: New utility unit with nameplate capacity over 25 MW and not otherwise exempt.
	Project: Project includes utility units with nameplate capacity over 25 MW. Project does not qualify for an exemption.
	Compliance: An acid rain permit will be obtained for the project.

[a] An air quality impact analysis was performed and BACT will be applied for $PM_{2.5}$, which has not yet been listed in R18-2-101(104)(a) or R18-2-407. See Sections 4 and 5 of this application for further information.

Notes:

BACT = Best available control technology
CFR = Code of Federal Regulations
MW = Megawatt
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers

Acid Rain Permitting Requirements

AAC Title 18, Chapter 2, Article 3, Section R18-2-333 incorporates the federal Acid Rain Program regulations by reference. These regulations include a permitting requirement for fossil fuel-fired combustion devices with nameplate capacity over 25 MW that produce electricity for sale. The Bowie Power Station will include devices with nameplate capacity greater than 25 MW and an acid rain permit is required. The acid rain permitting requirement, which is found in 40 Code of Federal Regulations (CFR), Part 72, Subpart C, has been included in Table 3-1. The acid rain permit application for the project is included in Appendix C.

Hazardous Air Pollutant Permitting Requirements

AAC Title 18, Chapter 2, Article 3, Section R18-2-302(D) prohibits construction of a new major source of HAPs unless maximum achievable control technology (MACT) requirements will be met. The federal MACT requirements are incorporated by reference in Article 11, Section R18-2-1101(B).

A source is a major HAP source if it will emit 10 tpy of a single HAP or 25 tpy of total HAPs. Emission estimates for the Bowie Power Station show total HAPs of 6.7 tpy and highest single HAP emissions of approximately 3.6 tpy. These values are below the major source thresholds. The project is not a major HAP source and the MACT requirements applicable to major sources do not apply.

Arizona Revised Statutes (ARS) Section 49-426.06 requires the establishment of a state HAP program. The state HAP program is codified in AAC Title 18, Chapter 2, Article 17 and became effective on January 1, 2007. The program applies to new and modified major sources of HAPs and to

covered minor HAP sources. All federal HAPs are included and the state also has authority to list additional state HAPs, though none are included in the current rule. Minor sources that are subject to the rule are those that belong to a category listed in ARS Section 49-426.05 that have the potential to emit 1 tpy of a single HAP or 2.5 tpy of a combination of HAPs.

Sources subject to the state HAPs program must obtain an air quality permit prior to commencing construction or modification. Major sources that are not subject to an emission limitation under 40 CFR Part 61 or Part 63 must install Arizona Maximum Achievable Control Technology (AZMACT). Covered minor sources must install Hazardous Air Pollutant Reasonably Available Control Technology (HAPRACT). AZMACT is an emission standard that requires the maximum degree of reduction in emissions of the HAPs subject to the program, while HAPRACT is defined as an emission standard that is determined to be reasonably available for a source, taking into consideration the air quality impact of the standard, the cost of compliance, the demonstrated reliability and widespread use of the technology required to meet the standard, and any non-air quality health and environmental impacts and energy requirements. The level of technology that qualifies as AZMACT or HAPRACT is determined on a case-by-case basis. A stationary source may obtain an exemption from AZMACT or HAPRACT by conducting a Risk Management Analysis that demonstrates that HAP emissions from the source will not adversely affect human health.

The Bowie Power Station will be neither a major source of HAPs nor a covered minor source. Therefore, the Bowie Power Station is not subject to the state HAP program in Article 17.

3.2 Emission Limits and Associated Monitoring Requirements

A key permit application requirement for new sources is the identification of applicable requirements. As previously indicated, a detailed listing of requirements applicable to the Bowie Power Station is provided in Appendix C. To assist in permit application processing, a summary of the emission limits and monitoring requirements applicable to the turbines, duct burners, auxiliary boiler, and emergency fire pump is provided in Table 3-2.

3.3 Greenhouse Gas Requirements

Reporting and permitting requirements for GHG emissions are the subject of federal regulations. This section discusses the GHG reporting requirements, as well as the permitting requirements that apply to the Bowie Power Station.

3.3.1 Mandatory Reporting of Greenhouse Gases Rule

In September 2009, EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule. The rule requires reporting of GHG emissions from large sources and suppliers in the United States, and is intended to collect accurate and timely emissions data to inform future policy decisions.

Under the rule, suppliers of fossil fuels or industrial greenhouse gases, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. The rule became effective December 29, 2009, and is codified in 40 CFR 98.

Table 3-2. Emission Limits and Associated Monitoring Requirements

Regulatory Citation	Requirement, Applicability, and Compliance
R18-2-702(B)	**Requirement:** Opacity shall not be greater than 40%.
	Applicability: Existing sources.[a]
	Project: Auxiliary boiler and cooling tower are existing sources because no new source performance standards from Article 9 are applicable to them.
	Compliance: Auxiliary boiler will combust natural gas. PM emissions from natural gas combustion are small; opacity levels will be well below the limit. Visible plumes from the cooling towers will be composed of uncombined water. Visible emissions resulting from uncombined water do not constitute a violation [R18-2-702(C)].
R18-2-724(C)(1)	**Requirement:** PM emissions must not exceed the limit obtained from the following equation: Emissions (lb/hr) = 1.02 x (heat input [MMBtu/hr])$^{0.769}$
	Applicability: Fossil fuel-fired industrial and commercial equipment meeting the following criteria: ▸ Heat input rate of less than 250 MMBtu/hr; ▸ Aggregate heat input for equipment on premises rated greater than 500,000 Btu/hr. ▸ Fuel is "burned for the primary purpose of producing steam, hot water, hot air or other liquids, gases or solids and in the course of doing so the products of combustion do not come into direct contact with process materials."
	Project: Auxiliary boiler has a heat input of 50 MMBtu/hr, which is less than 250 MMBtu/hr but greater than 500,000 Btu/hr. Fuel is burned to produce steam.
	Compliance: 1.02 x $50^{0.769}$ = 20.7 lb/hr The auxiliary boiler PM emission rate of 0.35 lb/hr is well below the 20.7 lb/hr limit that results from the equation.
R18-2-333(A) 40 CFR 72.9(c)	**Requirement:** Facility must hold sufficient SO_2 allowances for the project.
	Applicability: Affected sources subject to acid rain provisions.
	Project: Project is an affected source subject to the acid rain provisions.
	Compliance: The necessary allowances will be obtained.
R18-2-333(A) 40 CFR 75.10(a) and (c) 40 CFR 75.11(d)	**Requirement:** SO_2, NO_x, CO_2 emissions, and heat input must be determined.
	Applicability: Affected units subject to acid rain emission limitations. Gas-fired units are exempt from opacity monitoring requirements by 40 CFR 75.14(c).
	Project: Project includes affected units subject to acid rain emission limitations. Turbines are gas-fired units.
	Compliance: Monitoring will be conducted as required.
40 CFR 60, Subpart IIII 60.4205(c) 40 CFR 63, Subpart ZZZZ 63.6590(c)	**Requirement:** Comply with 40 CFR 63, Subpart ZZZZ by complying with emission standards for stationary fire pump engines for appropriate model year and maximum engine power in Table 4 to 40 CFR 60, Subpart IIII.
	Applicability: 40 CFR 63, Subpart ZZZZ: New or reconstructed stationary RICE subject to regulations under 40 CFR 60. 40 CFR 60, Subpart IIII: Compression ignition stationary fire pump engines with a displacement less than 30 liters per cylinder.
	Project: Fire pump is a new stationary RICE subject to 40 CFR 60, Subpart IIII. Fire pump will have a displacement less than 30 liters per cylinder.
	Compliance: A fire pump engine certified to the appropriate emission standards in Table 4 to 40 CFR 60, Subpart IIII will be purchased and operated in accordance with manufacturer's recommendations. Emission limits: NO_x + NMHC = 3.0 g/hp-hr; CO: 2.6 g/hp-hr; PM: 0.15 g/hp-hr; ultra-low sulfur fuel

Table 3-2. (Continued)

Regulatory Citation	Requirement, Applicability, and Compliance
40 CFR 60, Subpart KKKK 60.4320	**Requirement:** Do not emit oxides of nitrogen from the turbines in excess of 15 parts per million at 15% oxygen or 54 nanograms per Joule (1.2 pounds per megawatt-hour) of useful output.
	Applicability: Stationary combustion turbines: ▸ Heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour based on higher heating value of fuel; and ▸ Commenced construction after February 18, 2005.
	Project: Project includes combustion turbines with heat inputs greater than 10.7 gigajoules (10 MMBtu) per hour. Construction will commence after February 18, 2005.
	Compliance: Continuous emissions monitoring systems will be used to verify compliance with the limit.
40 CFR 60, Subpart KKKK 60.4330	**Requirement:** Do not emit from the turbines sulfur dioxide in excess of 110 nanograms per Joule (0.90 pounds per megawatt-hour) gross output. or Do not burn fuel with total potential sulfur emissions in excess of 26 nanograms per Joule (0.060 pounds sulfur dioxide per MMBtu) heat input.
	Applicability: Stationary combustion turbines: ▸ Heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour based on higher heating value of fuel; and ▸ Commenced construction after February 18, 2005.
	Project: Project includes combustion turbines with heat inputs greater than 10.7 gigajoules (10 MMBtu) per hour. Construction will commence after February 18, 2005.
	Compliance: Continuous emissions monitoring systems will be used to verify compliance with the limit.
40 CFR 60, Subpart KKKK 60.4340	**Requirement:** Demonstrate compliance with oxides of nitrogen limits using one of the methods specified in 60.4340.
	Applicability: Stationary combustion turbines: ▸ Heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour based on higher heating value of fuel; and ▸ Commenced construction after February 18, 2005.
	Project: Project includes combustion turbines with heat inputs greater than 10.7 gigajoules (10 MMBtu) per hour. Construction will commence after February 18, 2005.
	Compliance: Compliance with oxides of nitrogen limits will be demonstrated using one of the specified methods.

Table 3-2. (Continued)

Regulatory Citation	Requirement, Applicability, and Compliance
40 CFR 60, Subpart KKKK 60.4360, 60.4365, 60.4370	**Requirement:** Monitor and record total sulfur in the natural gas fuel as specified in 60.4360 or Demonstrate that potential sulfur emissions from the fuel will not exceed 26 nanograms sulfur dioxide per Joule (0.060 pounds per MMBtu) using one of the methods specified in 60.4365.
	Applicability: Stationary combustion turbines: ▸ Heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour based on higher heating value of fuel; and ▸ Commenced construction after February 18, 2005.
	Project: Project includes combustion turbines with heat inputs greater than 10.7 gigajoules (10 MMBtu) per hour. Construction will commence after February 18, 2005.
	Compliance: Fuel sulfur will either be measured and recorded or the potential emissions will be demonstrated to be less than the limit as required.

[a] Existing source is defined in the Arizona Administrative Code (R18-2-101.41) as "any source which does not have an applicable new source performance standard under Article 9."

Notes:

%	=	Percent
Btu	=	British thermal unit
CFR	=	Code of Federal Regulations
CO_2	=	Carbon dioxide
g/hp-hr	=	Grams per horsepower-hour
hr	=	Hour
lb	=	Pound
MMBtu	=	Million British thermal units
NMHC	=	Non-methane hydrocarbons
NO_x	=	Oxides of nitrogen
PM	=	Particulate matter
RICE	=	Reciprocating internal combustion engine
SO_2	=	Sulfur dioxide

The rule requires reporting of anthropogenic GHG emissions covered under the United Nations Framework Convention on Climate Change: carbon dioxide (CO_2), methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, as well as other fluorinated gases (e.g., nitrogen trifluoride and hydrofluorinated ethers).

The Bowie Power Station will be subject to the rule because it is an electricity generation facility that reports CO_2 emissions year-round through 40 CFR 75, which is one of the "all in" categories listed in Table A-3 of 40 CFR 98, Subpart A. Facilities such as the Bowie Power Station that also report to the Acid Rain Program will continue to submit reports under 40 CFR 75, and will also submit annual GHG emission reports under the GHG reporting rule. The facility will be required to report all emissions of CO_2, nitrous oxide, and methane from the turbines, duct burners, and the auxiliary boiler on an annual basis. Reports are due by March 31 for emissions during the previous calendar year.

Greenhouse gas emissions have been calculated for the Bowie Power Station, and are shown in Table 3-3.

Table 3-3. Project Greenhouse Gas Emissions

Equipment	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	SF_6 (tpy
Turbines and Duct Burners	1,751,052	33.0	3.3	
Auxiliary Boiler	1,315	0.02	0.002	
Emergency Fire Pump	15	0.001	0.0001	
Circuit Breakers				0.0009
Totals	1,752,382	33.0	3.3	0.0009

Notes:

CH_4	=	Methane
CO_2	=	Carbon dioxide
N_2O	=	Nitrous oxide
SF_6=	=	Sulfur hexafluoride
tpy	=	tons per year
<	=	Less than

3.3.2 GHG Permitting Requirements

On May 13, 2010, EPA finalized permitting requirements for large sources of GHG emissions. On December 29, 2010 (75 Federal Register [FR] 81874), EPA finalized findings that seven states (including Arizona) failed to submit revised state implementation plans that address PSD permitting requirements for GHG emission sources by a specified due date. On December 30, 2010 (75 FR 82246), EPA finalized the federal implementation plan (FIP) for PSD permits for Arizona. Under the federal PSD FIP, the state or local permitting agency remains the applicable permitting authority for PSD permits, except for those portions of permits that address GHG emissions. EPA is the permitting authority for the portion of PSD permits that address GHG emissions; however, EPA has delegated this authority to ADEQ and GHG PSD requirements are addressed in this application.

3.4 US Fish and Wildlife Service Requirements

The EPA has requested that FWS be notified when PSD applications have been received. One purpose of this notice is to assist EPA in carrying out its responsibilities under Section 7 of the Endangered Species Act. An FWS endangered species assessment was requested and a copy of this assessment can be found in Appendix C. The FWS review of the proposed project concluded that there were no endangered species concerns.

3.5 National Historic Preservation Act Sites

Section 106 of the NHPA requires that, prior to the approval of the expenditure of any funds on, or prior to the issuance of any license for, an undertaking, the EPA must take into account the effects of its undertakings on historic properties and allow the Advisory Council on Historic Preservation a reasonable opportunity to comment on such undertakings. Section 106 consultations assess whether historic properties exist within an undertaking's area of potential effect and, if so, whether the undertaking will adversely affect such properties.

The term "historic properties" means prehistoric or historic districts, sites, buildings, structures, or objects included in, or eligible for inclusion in, the National Register of Historic Places maintained by the US Department of the Interior. Historic properties include properties of traditional religious and cultural importance to Indian Tribes.

Table 3-4 lists the National Register of Historic Places sites within approximately 50 kilometers of the Bowie site.

Table 3-4. National Register of Historic Places Sites within 50 Kilometers of the Bowie Power Station Site

Site name	Location	Year Added	Approximate Distance from Bowie Power Station	Brief Description
Fort Bowie National Historic Site	South of Bowie, Arizona	1972	23 kilometers	Significant for Native American, architecture, military, 1875-1899, 1850-1874. Federally owned park.
Bear Spring House, Guardhouse, and Spring	South of Bowie, Arizona	1983	24 kilometers	Significant for exploration/settlement, military, architecture, 1875-1899, 1850-1874. Currently a single dwelling.
Benjamin E. Briscoe House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, 1875-1899. Currently a single dwelling.
Crowley House	Willcox, Arizona	1987	34 kilometers	Significant for exploration/settlement, architecture, 1900-1924, 1875-1899. Currently a single dwelling.
John Gung'l House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, 1900-1924. Currently a single dwelling.
Johnson-Tillotson House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, 1900-1924. Currently a single dwelling.
Joe Mee House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, 1900-1924. Currently a single dwelling.
Morgan House	Willcox, Arizona	1987	34 kilometers	Significant for commerce, architecture, 1900-1924, 1875-1899. Currently a single dwelling.
John H. Norton and Company Store	Willcox, Arizona	1983	34 kilometers	Significant for architecture, 1900-1924, 1875-1899. Currently privately owned for commerce/trade.
Railroad Avenue Historic District	Willcox, Arizona	1987	34 kilometers	Significant for exploration/settlement, commerce, transportation, agriculture, 1925-1949, 1900-1924, 1875-1899. Currently privately owned business.
Harry Saxon House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, 1900-1924. Currently a single dwelling.
Schwertner House	Willcox, Arizona	1983	34 kilometers	Significant for exploration/settlement, architecture, 1875-1899. Currently a privately owned hotel.
Pablo Soto House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, commerce, 1875-1899. Currently a single dwelling.
Willcox Women's Club	Willcox, Arizona	1987	34 kilometers	Significant for architecture, community planning and development, 1925-1949. Currently a privately owned clubhouse.
J.C. Wilson House	Willcox, Arizona	1987	34 kilometers	Significant for architecture, commerce, 1900-1924. Currently a single dwelling.
Hooker Town House	Willcox, Arizona	1987	35 kilometers	Significant for architecture, agriculture, 1900-1924. Currently a single dwelling.
Stafford Cabin	Chiricahua National Monument	1975	41 kilometers	Significant for agriculture, 1900-1924, 1875-1899. Federally owned park.
Say Yahdesut "Point of Rocks" Chiricahua National Monument Historic Designed Landscape	Chiricahua National Monument	2008	41 kilometers	Significant for landscape architecture, politics/government, architecture, conservation, social history, entertainment/recreation, 1925-1949, 1900-1924. Federally owned for outdoor recreation.

A cultural survey was conducted on the Bowie Power Station site and along a proposed transmission line that would extend from the power plant site approximately 14.3 miles in a northwesterly direction into Graham County, Arizona to interconnect with Tucson Electric Power Company's existing Greenlee-Vail and Springerville-Vail transmission line at a point located near US Highway 191. A report of the survey was issued in August 2001. The report titled *Draft Cultural Resource Survey for the Proposed Bowie Power Station and Transmission Line, Graham and Cochise Counties, Arizona* was prepared by Kris Dobschuetz of Environmental Planning Group (EPG 2001). The cultural resource survey was approved by the State Historic Preservation Office in 2001.

The survey resulted in the identification of one historic structure, a portion of the Arizona Eastern Railroad, historically known as the Gila Valley Globe & Northern Railroad (GVG&N) located within Section 6, Township 12 South, Range 28 East (United States Geological Survey [USGS] 7.5-minute Fisher Hills topographic quadrangle 1979) that could be eligible for listing on the National Register.

The survey also found and recorded a historic feature, an abandoned railroad siding associated with the GVG&N located on private land, state trust land, and Bureau of Land Management land within the E1/2 of Section 6 and the NW1/4 of Section 8, Township 12 South, Range 28 East and the SE1/4 of Section 31, Township 11 South, Range 28 East (USGS Fisher Hills Quadrangle, 7.5-minute series, 1979). The report recommended this site as not eligible for listing on the National Register.

In November 2007, a report titled *A Cultural Resource Survey for the Realignment of Portions of the Proposed Bowie Transmission Line, Graham and Cochise Counties, Arizona* was prepared by Robert A. Rowe of Environmental Planning Group (EPG 2007). This survey identified two new historic sites. One site, the Javalina Site, is a prehistoric artifact scatter site located on Arizona State Land Department administered land within Township 11 South, Range 28 East of Section 6, NW SW (USGS Fisher Hills Quadrangle 7.5-minute series). The report determined that the site likely represented a short-term limited activity area that was used during the prehistoric period. It was recommended as not eligible for listing on the National Register.

The other historic site, the Willow Spring Wash Site, is a high density artifact scatter located on the southern and northern banks of Gold Gulch in Cochise County, Arizona. This site was also determined to be a short-term limited use area occupied during the Formative Period. It was also recommended as not eligible for listing on the National Register.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSES

This section presents the required best available control technology (BACT) analyses for the Bowie Power Station project.

4.1 Applicability

The Arizona Administrative Code (AAC), Title 18, Chapter 2, Article 4, Section R18-2-406 requires that BACT be applied for each pollutant with a significant potential to emit as defined in Section R18-2-101(130). The significance levels are pollutant specific and are shown in Table 4-1. Also shown in Table 4-1 are the potential emissions from the Bowie Power Station.

Prevention to Significant Deterioration (PSD) requirements, including BACT, are applicable to greenhouse gas (GHG) emissions as indicated in 40 Code of Federal Regulations (CFR) 52.21(b)(49)(iv). There is a delegation agreement in place between the US Environmental Protection Agency (EPA) and the Arizona Department of Environmental Quality (ADEQ) under which ADEQ implements the PSD requirements for GHGs. PSD requirements apply to GHG emissions if a new source is major for a regulated PSD pollutant and GHG emissions are equal to or greater than 75,000 tons per year carbon dioxide equivalent emissions (CO_2e). CO_2e emissions are included in Table 4-1.

Table 4-1. Project Potential Emissions and Regulatory BACT Thresholds

Pollutant	Significance Level (tpy)	Project Potential Emissions (tpy)
Oxides of Nitrogen	40	139.4
Carbon Monoxide	100	161.5
Volatile Organic Compounds	40	30.6
Sulfur Dioxide	40	30.0
Particulate Matter	25	68.3
PM_{10}	15	66.5
$PM_{2.5}$[a]	10	64.5
Carbon Dioxide Equivalent	75,000	1,754,122.1

[a] Direct $PM_{2.5}$ emissions. The definition of significant for $PM_{2.5}$ also includes 40 tons per year oxides of nitrogen or 40 tons per year sulfur dioxide emissions.

Notes:

BACT	=	Best available control technology
PM_{10}	=	Particulate matter less than 10 micrometers diameter
$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers diameter
tpy	=	Tons per year

The project emissions are above the significance threshold for oxides of nitrogen (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic equivalent diameter less than or equal to a nominal 10 micrometers (PM_{10}), particulate matter with an aerodynamic equivalent diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$), and CO_2e. BACT analyses for these pollutants must be performed. The required BACT analyses for the turbines/duct burners, auxiliary boiler, emergency fire pump engine, cooling tower, and circuit breakers are presented below.

4.2 BACT Analysis Methodology

The BACT analyses conducted addresses the ADEQ BACT definition and have been prepared following the steps of the EPA's top-down BACT analysis method.

4.3 Top-Down BACT Analysis Methodology Summary

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memo that implemented certain program initiatives to improve the New Source Review (NSR) program, one of which was the "top-down" method for determining BACT. The steps for conducting a top-down BACT analysis are listed in EPA's *New Source Review Workshop Manual*, Draft, October 1990 (EPA 1990). Each step of the top-down method of determining BACT is described briefly below.

4.3.1 Step 1: Identify All Control Technologies

The first step in the top-down method is to list all available control technologies that may apply to the emission unit and the regulated pollutant being evaluated. The list of control alternatives should include existing technologies and innovative control technologies. Technologies required by lowest achievable emission rate (LAER) determinations must also be included. According to EPA's *New Source Review Workshop Manual*, "an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

4.3.2 Step 2: Eliminate Technically Infeasible Options

The second step in the top-down method is to eliminate any of the identified control technologies that are technically infeasible with respect to the emission unit being evaluated. A determination of technical infeasibility is based on physical, chemical, and engineering principles. Technical difficulties that would preclude successful application of the control technology to the emission unit under review are also considered. All technologies that are identified as being technically infeasible are then removed from further review in the BACT analysis.

4.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In the third step of the top-down method, all remaining control technologies that were not eliminated as being technically infeasible are ranked and listed in order of control effectiveness for the pollutant under review, with the most effective control at the top of the list.

4.3.4 Step 4: Evaluate Most Effective Controls and Document Results

In the fourth step of the top-down method, an analysis is presented that details the associated environmental, energy, and cost impacts associated with the control technologies. An objective evaluation of each impact, including both beneficial and adverse impacts, should be included. If an applicant is proposing the top control technology, then detailed impact information is not necessary. If the top control technology is not chosen, then the associated energy, environmental, and economic impacts are considered. If, based on the impacts, the top technology is shown to be inappropriate, the analysis proceeds to the next most effective control in the listing. The process continues until the technology under consideration is not eliminated because of energy, environmental, or economic impacts.

4.3.5 Step 5: Select BACT

The most effective control option that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

4.4 Turbine and Duct Burner Normal Operation BACT Analyses

The exhaust from the turbines will be combined with the exhaust from the duct burners. Research into duct burners has revealed that there are no independent methods available to reduce or control emissions from duct burners. Add-on control devices that would control emissions from the turbines will also control emissions from the duct burners. As a result, for the add-on control methods reviewed, emissions from the duct burners and turbines are analyzed together.

4.4.1 Turbine and Duct Burner Normal Operation NO_x Analysis

The BACT analysis for NO_x emissions from the General Electric (GE) Frame 7FA turbines and duct burners is presented below.

Step 1: Identify All Control Technologies Turbine and Duct Burner Normal Operation NO_x Analysis

Potential NO_x control technology options for the turbines and duct burners are:

- Catalytic combustion (K-LEAN™);
- Lean Pre-Mix Combustion, also referred to as dry low NO_x combustion (DLN);
- Water or steam injection;
- Selective Non-Catalytic Reduction (SNCR);
- Selective Catalytic Reduction (SCR); and
- EMx™.

Catalytic Combustion

Catalytic combustion is a NO_x pollution prevention option for combustion turbines that limits the temperature in the combustor preventing NO_x formation. The only commercially available catalytic combustion system for combustion turbines is K-LEAN™ (formerly Xonon™), available from Kawasaki. K-LEAN™ is only available on small turbines (<20 megawatts [MW]). The use of Xonon™ technology on a 750 MW combustion turbine project south of Bakersfield, California called the Pastoria Energy Facility was to have demonstrated the technology on large turbines. Instead, the project was ultimately constructed using DLN combustion turbines equipped with SCR.

Catalytic combustion technology has yet to be demonstrated on large combustion turbines and is therefore not an available technology for this project.

Lean-Premix Combustion

Lean-premix combustion, also referred to as DLN, is also a NO_x pollution prevention option for combustion turbines. DLN limits NO_x formation by limiting combustion temperature and equalizing temperature distribution. This is accomplished by thoroughly premixing fuel with air in a lean (containing more air than is stoichiometrically required) mixture prior to injection into the combustion chamber. Turbines available for purchase in the size-range of this project's turbines are usually equipped with a lean-premix combustion system.

SCR

SCR is a post-combustion NO_x control method in which ammonia is injected into the exhaust stream in a catalytic reactor. SCR is widely used on combined-cycle combustion turbines and is an available technology for NO_x control for the turbines and duct burners.

EMx™

EMx™ (formerly $SCONO_x$) is a post-combustion catalytic oxidation and absorption NO_x control system offered by EmeraChem. This technology uses parallel catalyst beds to reduce NO_x and CO emissions simultaneously. The EMx™ system includes a second catalyst bed knows as ES_x™. ES_x™ is needed to capture sulfur compounds in the exhaust stream. The EMx™ bed preferentially absorbs sulfur compounds masking the catalyst. Sulfur compounds have been a problem for the EMx™ catalyst even for turbines fired exclusively on natural gas.

The EMx™ catalyst beds become saturated with NO_x and have to be regenerated as frequently as every 20 minutes. Regeneration takes from 5-7 minutes. The beds are taken off line using mechanical dampers and a dilute concentration of hydrogen in steam is used to regenerate the off-line bed. The regeneration gas, containing molecular hydrogen and carbon dioxide (CO_2) in steam, is produced from natural gas.

The ES_x™ catalyst upstream of EMx™ catalyst is regenerated at the same time. The ES_x™ catalyst oxidizes sulfur dioxide (SO_2) to sulfur trioxide (SO_3). During regeneration, the SO_2 is released and exhausted with the regeneration gas.

EMx™ has been demonstrated on several small turbines. The largest is a 45 MW turbine at the Redding, California municipal power plant. EMx™ has not been demonstrated on a large turbine or on a turbine configuration that includes duct firing. The La Paloma Generating Project in California initially proposed to demonstrate EMx™ on 150 MW turbines, but ultimately an SCR system was installed instead. This was also the case with the Otay Mesa project also located in California. Over 10 years ago, Goal Line Environmental Technologies LLC, the inventor of $SCONO_x$, entered into an agreement with Alstom Power Company making Alstom the EMx™ supplier for turbines larger than 100 MW. That agreement never resulted in the use of EMx™ on a turbine larger than 100 MW.

There are many questions surrounding the scale up and reliability of the EMx™ technology. Turbine size has an impact on the physical and chemical characteristics of the exhaust stream. Although the exhaust streams from turbines of different sizes may contain the same pollutants, the pollutant concentrations will be different. In addition, the exhaust temperatures and flow rates will also differ. The addition of duct burner exhaust further differentiates the exhaust streams from this project's turbines and duct burners from the exhaust streams upon which EMx™ has been demonstrated.

A primary concern related to use of EMx™ on large turbines is the distribution of both exhaust gas and regeneration gas across the catalyst. To achieve low NO_x emission levels, proper distribution across the catalyst is critical. In fact, the first generation of the $SCONO_x$ system had to be taken out of operation because of problems with regeneration gas distribution.

The larger heat recovery steam generator (HRSG) associated with a turbine larger than the turbines using EMx™ presents a significant challenge in achieving proper regeneration gas distribution and is a hurdle in system scale up. A model of fluid flow dynamics and distribution generated by Alstom Power indicated that the EMx™ regeneration gas delivery method used on the smaller turbines required redesign to achieve appropriate gas distribution on a large turbine (Czarnecki 2001). Several mechanical distribution systems were considered to help achieve uniform gas distribution. A design was chosen and flow scale modeling was performed to verify the effectiveness of the design (Czarnecki 2001). While the

research results helped select a design, the newly designed manifold system has not been tested on a large gas turbine.

In addition to regeneration gas distribution, there is also a scale up concern associated with the many mechanical linkages, activators, and damper seals that must operate reliably for the system to remain online and provide successful emission control. Alstom also researched damper system scale-up. Four full-scale damper assemblies were tested at operation temperature for 100,000 cycles (equivalent to about three years of operation in the field). This testing revealed several problems. Alstom believed they had solved the identified problems (Czarnecki 2001). These solutions have not been tested on a large turbine in commercial operation.

While research and development has been performed to design a EMx™ system that can be used successfully on large-scale turbines, questions associated with the reliability and long-term performance of a large-scale EMx™ system remain. Until EMx™ is operated commercially on a large-scale turbine and on a turbine configuration including duct firing, it cannot be considered a viable control option for large turbines and turbines systems with duct firing.

Even with the many concerns surrounding the scale up and reliability of the EMx™ system, it has been considered an available technology for large turbines by some regulatory agencies and will be further evaluated for this project.

Step 2: Eliminate Technically Infeasible Options Turbine and Duct Burner Normal Operation NO_x Analysis

Two of the control options are technically infeasible for the Bowie turbines and duct burners.

Water or Steam Injection

Water or steam injection has been widely used for NO_x emission control. Water or steam is injected into the combustion chamber and acts as a heat sink, reducing the formation of thermal NO_x. This control method works well on diffusion flame turbines, but injection of steam or water into the combustion zone does not enhance NO_x emission reductions on DLN turbines. As a result, water or steam injection is not considered a technically feasible NO_x reduction method for this project.

SNCR

SNCR is a post-combustion control method in which ammonia or urea is injected into the exhaust stream, reducing NO_x to nitrogen and water. SNCR works in a temperature range of 1,600 to 2,200 degrees Fahrenheit (^oF) and requires a residence time of 100 milliseconds (EPA 1993). The temperature range required for SNCR is higher than the exhaust temperature from combined-cycle combustion turbines and the flow velocities necessary to meet the residence time are much slower than the flow velocities for combined-cycle combustion turbines. SNCR is therefore not considered a technically feasible NO_x reduction method for this project.

Remaining Technologies

The remaining control technologies that are technically feasible and available are DLN and SCR. These two technologies, along with EMx™, are analyzed further below.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Turbine and Duct Burner Normal Operation NO_x Analysis

Turbines available for purchase in the size-range of this project's turbines are equipped with DLN. DLN is built into the turbines and is integral to turbine operation. Use of DLN is a form of

pollution prevention. In EPA's *New Source Review Workshop Manual* (EPA 1990), as part of a discussion on calculating baseline emissions for determining cost effectiveness, the application of post-process emission controls to "inherently lower polluting processes" is addressed. This discussion indicates that for inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. A turbine equipped with DLN is an "inherently lower polluting process." As such, post-combustion control technologies will be evaluated in conjunction with DLN.

Emission rates for each of the technically feasible technologies are required to rank the technologies in order of effectiveness. GE guarantees an exhaust NO_x concentration of 9 parts per million by volume (ppmv) at 15% oxygen (O_2) from the GE Frame 7FA turbines. The turbines and duct burners combined will have a maximum uncontrolled emission concentration of 11.9 ppmv at 15% O_2. The Bowie turbines equipped with SCR will comply with a NO_x emission limit of 2 ppmv at 15% O_2 on a 1-hour average basis. The control technology ranking using these emission concentrations is shown in Table 4-2.

Table 4-2. NO_x Control Technology Emission Rate Ranking

Control Technology	NO_x Emissions (ppmv)[a]	NO_x Emissions (tpy)[b]	Reduction from Uncontrolled (tpy)
SCR and DLN	2.0	138.9	452.6
DLN	11.9	591.5	NA

[a] Emission concentration for each turbine and duct burner pair during normal operation.
[b] Emissions for two turbine and duct burner pairs on an annual basis including startup, shutdown, and tuning emissions.

Notes:

DLN	=	Dry low NO_x
ppmv	=	Parts per million by volume
NA	=	Not applicable
SCR	=	Selective Catalytic Reduction
NO_x	=	Oxides of nitrogen
tpy	=	Tons per year

As indicated previously, although EMx™ has not been demonstrated on large turbines, many regulatory agencies have treated it as available and it will be evaluated in the remaining steps of this analysis. The facility with the largest turbine equipped with EMx™ is the Redding municipal plant. The permit for the facility included a NO_x demonstration emission limit of 2 ppmv NO_x at 15% O_2. Although the Redding facility has reportedly had difficulty meeting this limit (BAAQMD 2010a), for this analysis it will be assumed that a larger turbine equipped with EMx™ could meet the Redding municipal plant's permit limit. If EMx™ were demonstrated in practice on large turbines and could meet the Redding municipal plant NO_x permit limit, EMx™ with DLN would appear in Table 4-2 in the same place as SCR and DLN. NO_x emissions would be 2.0 ppmv at 15% O_2 and 138.9 tons per year (tpy). The reduction from DLN alone would be 452.6 tpy.

Step 4: Evaluate Most Effective Controls and Document Results Turbine and Duct Burner Normal Operation NO_x Analysis

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. For this project, the most effective technologies are SCR with DLN and EMx™ with DLN.

SCR and DLN

There are energy and environmental impacts associated with the use of SCR to control emissions from DLN turbines. The energy impacts result from the increased backpressure the control system places on the turbine. The increased backpressure increases the heat input required to produce power and reduces the peak power output of the turbine. A pressure drop of 3 inches is expected for SCR.

A document looking at the use of CO oxidation catalysts to control hazardous air pollutant (HAP) emissions from gas turbines includes an estimate of the energy penalties associated with increased backpressure. This document, *Cost-Effectiveness of Oxidation Catalyst, Control of Hazardous Air Pollutant (HAP) Emissions from Stationary Combustion Turbines*, prepared by the Combustion Gas Turbine Working Group of the Industrial Combustion Coordinated Rulemaking (ICCR), dated September 4, 1998 (ICCR 1998a), includes an estimate of the increased heat rate input required to compensate for the pressure drop associated with the catalyst. The Work Group used a heat rate increase of 0.105% per inch of pressure drop measured in inches of water. The document goes on to say that this is a low estimate and that most turbines would experience a higher increased heat rate requirement. For heavy-frame turbines, the document cites a rule of thumb estimate of 0.15% penalty per inch of pressure drop.

The document also discusses the loss of power production capacity when the turbine operates at full load that results from the increased exhaust backpressure. This power loss is 0.15% per inch of pressure drop. This reduced capacity is also an energy impact.

Based on the additional 3 inches of pressure drop associated with the SCR system, the energy penalty for the system would be 0.45% heat input penalty and a 0.45% peak power penalty.

SCR technology has two well-documented potential environmental impacts, ammonia emissions and handling and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases and ammonia injection control limitations. This ammonia slip is either directly emitted or reacts with the sulfur and nitrogen in the exhaust stream to form ammonia salts. The ammonia salts are emitted as PM. Dispersion modeling for the Bowie project has shown that the impacts of PM_{10} and $PM_{2.5}$ emissions will be below the National and Arizona Ambient Air Quality Standard (NAAQS/AAAQS) limitations.

The safety aspects of handling ammonia were addressed by EPA in a document titled *NO_x Control on Combined Cycle Turbine* (EPA 2000) dated August 4, 2000. This document indicates that although ammonia is identified by EPA as an extremely hazardous substance, it is typically handled safely and without incident. This is especially true of the aqueous ammonia (industrial grade) that will be used at the Bowie Power Station. The use of aqueous ammonia rather than anhydrous ammonia greatly reduces the risks associated with ammonia use. Use of aqueous ammonia greatly reduces the probability and severity of accidental releases. Spills associated with aqueous ammonia can also be more easily contained and cleaned up. By using aqueous ammonia, the safety issues associated with ammonia handling will be minimized.

The other potential environmental impact associated with SCR is disposal of the catalyst. The catalysts used in SCR systems must be replaced every three to six years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when disposing of the spent catalyst. This potential impact is mitigated through recycling. The spent catalyst is returned to the catalyst manufacturers for reactivation or recycling (ICAC 1997).

EMx™ and DLN

There are energy, environmental, and cost impacts associated with EMx™. As with SCR, energy impacts result from the increased backpressure the control system places on the turbine. Alstom had estimated that the EMx™ technology would cause a pressure drop of between 4 and 6 inches of water. Using the rule of thumb energy penalties of 0.15% per inch heat rate penalty and 0.15% per inch peak power penalty discussed previously, this would result in a heat input penalty of 0.6% to 0.9% and a peak power penalty of 0.6% to 0.9%.

In addition to the energy impacts associated with additional backpressure, additional energy impacts are associated with the catalyst regeneration process. Steam is needed for the EMx™ catalyst regeneration process. This steam would require energy to produce, and the diversion of steam would reduce the amount of electricity that each turbine system could generate. The use of natural gas to produce the hydrogen needed for regeneration would also result in slight energy impacts as that fuel could not be used for energy production.

There are also environmental impacts associated with EMx™. The EMx™ system does not use ammonia and therefore does not have associated ammonia emissions; however, the reaction used to control NO_x emissions results in increased emissions of CO_2:

$$2NO_2 + K_2CO_3 \rightarrow KNO_2 + KNO_3 + CO_2$$

where:

NO_2	=	Nitrogen dioxide
K_2CO_3	=	Potassium carbonate
KNO_2	=	Potassium nitrite
KNO_3	=	Potassium nitrate
CO_2	=	Carbon dioxide

In addition, the California Air Resources Board (CARB 2004a) has indicated that if regeneration of the EMx™ catalyst occurs at temperatures less than 500°F, small amounts of hydrogen sulfide (H_2S), a very toxic gas, may be produced.

The use of steam in the regeneration process and the need to periodically clean the catalysts with water results in increased water use associated with an EMx™ system. EmeraChem indicates that 80% of the water use associated with this steam consumption can be recovered.

As with SCR, eventually the EMx™ catalyst will have to be replaced. The EMx™ catalyst does not contain heavy metals or other hazardous materials. As a result, the spent catalysts are non-hazardous waste. The EMx™ catalyst contains platinum, a precious metal that would likely be recovered prior to catalyst disposal.

There are cost impacts associated with EMx™. There has been a recognized cost gap between SCR and EMx™. In 2009, EmeraChem indicated that as a result of advances in catalyst formulation and process improvements, the cost of EMx™ had come down and the economic gap between SCR and EMx™ had closed. The most recent publicly available cost information from EmeraChem is from a presentation made in California in August 2009. In that presentation, EmeraChem provided a cost of $15,651,488 for the total capital investment for an EMx™ system for a GE Frame 7FA turbine and a cost of $5,260,678 for the annual operating costs (Valmus 2009). This results in an annual cost of $6,979,127. Using an interest rate of 7% and an equipment life of 15 years, this yields a cost effectiveness for each Bowie turbine and duct burner of $30,840 per ton.

In the same presentation, EmeraChem provided costs for SCR of $12,687,346 for total capital investment and $4,961,113 per year for annual operating costs (Valmus 2009). For the Bowie project this yields an annual cost of $6,354,115 and a cost effectiveness for each turbine and duct burner of $28,078 per ton. Using the most recent publicly available EmeraChem cost information, the cost effectiveness of EMx™ is $2,762 per ton higher than SCR.

Step 5: Select BACT
Turbine and Duct Burner Normal Operation NOx Analysis

The final step in the top-down BACT analysis process is to select BACT. Both DLN with SCR and DLN with EMx™ can achieve the same emission limit and both have associated energy and environmental costs. The energy impacts are greater for EMx™ and EMx™ also has associated cost impacts relative to SCR. The energy, environmental, and cost impacts are summarized in Table 4-3.

As both DLN with SCR and DLN with EMx™ can achieve the same emission reduction and both have associated energy and environmental impacts, either technology could be used to meet a BACT emission limit of 2.0 ppmv at 15% O_2 on a 1-hour average. The Bowie project will use SCR and DLN because of the unproven nature of the technology, greater energy impacts, and greater cost of EMx™.

Table 4-3. NO_x Control Technology Energy, Environmental, and Cost Impacts[1]

Control Technology	Energy Impacts	Environmental Impacts	Cost Impacts[a]
SCR and DLN	▸ Pressure drop: Increase of 3 inches ▸ Heat input penalty: 0.45% ▸ Peak power penalty: 0.45%	▸ Ammonia emissions ▸ Increased PM emissions ▸ Ammonia handling safety considerations ▸ Catalyst disposal	--
EMx™ and DLN	▸ Pressure drop: Increase of 4 to 6 inches ▸ Heat input penalty: 0.60% - 0.90% ▸ Peak power penalty: 0.60% - 0.90% ▸ Steam consumption for catalyst regeneration — associated electricity generation loss and increased fuel use ▸ Use of natural gas to produce hydrogen	▸ CO_2 emissions ▸ Possible H_2S emissions ▸ Increased water use — steam consumption and catalyst cleaning	▸ Annual cost $625,012 per year higher ▸ Cost effectiveness $2,762 per ton higher

[a] For each turbine and duct burner pair.

Notes:

CO_2	=	Carbon dioxide
DLN	=	Dry low NO_x
H_2S	=	Hydrogen sulfide
PM	=	Particulate matter
SCR	=	Selective Catalytic Reduction
%	=	Percent

The BACT emission limit of 2.0 ppmv at 15% O_2 on a 1-hour average proposed for the Bowie project has been compared to other emission limits imposed on similar projects. EPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, a listing of turbine projects maintained by EPA, and information on projects

permitted in California and other states have been reviewed to compile a listing of turbine NO_x emission limits. This listing is provided in Appendix D.

Only one project with duct firing and an emission limit less than 2 ppmv at 15% O_2 on a 1-hour average was identified. The IDC Bellingham project was issued an emission limit of 1.5 ppmv. This project was cancelled and never constructed. As a result, compliance with this limit has not been demonstrated. The lowest demonstrated emission limit is therefore the limit proposed for this project for normal operations, 2.0 ppmv at 15% O_2 on a 1-hour average.

A BACT limit must not be higher than an emission limit in an applicable New Source Performance Standard (NSPS). The NO_x emission limit from 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply. The NO_x limit in this subpart is 15 ppmv at 15% O_2. The applicable NSPS limit is much higher than the 2.0 ppmv at 15% O_2 limit proposed as BACT.

Note that the emission limit proposed in this section as BACT for normal operations cannot be achieved during startup, shutdown, or tuning. As BACT must be applied at all times and the proposed normal operation emission limit is not achievable during other operating modes, a separate BACT analysis is required for startup, shutdown, and tuning. That analysis is provided in Section 4.4.4 of this document.

4.4.2 Turbine and Duct Burner Normal Operation CO Analysis

The BACT analysis for CO emissions from the GE Frame 7FA turbines and duct burners is presented below.

Step 1: Identify All Control Technologies
Turbine and Duct Burner Normal Operation CO Analysis

Four control technologies have been identified for CO control. They are:

- Catalytic combustion (K-LEAN™);
- EMx™;
- Oxidation catalyst; and
- Combustion controls.

Both the EMx™ and K-LEAN™ technologies were described in detail in Section 4.4.1. The CO catalyst is a post-combustion control device applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

As discussed in Section 4.4.1, the only commercially available catalytic combustion system for combustion turbines is K-LEAN™ (formerly Xonon™). K-LEAN™ is only available on small turbines (<20 MW). A 750 MW project south of Bakersfield, California was to be used to demonstrate the Xonon™ technology on larger turbines. The project was ultimately constructed using DLN combustion turbines equipped with oxidation catalysts. As a result, catalytic combustion has yet to be demonstrated on large combustion turbines and is not available for this project.

EMx™ (formerly $SCONO_x$) was discussed in detail in Section 4.4.1. It is a post-combustion catalytic oxidation and absorption control system that uses parallel catalyst beds to reduce NO_x and CO emissions simultaneously. It is offered by EmeraChem and has been demonstrated on several small turbines, the largest a 45 MW turbine. It has never been demonstrated on large frame-size turbines like those to be used at the Bowie Power Station. Concerns about the technical issues associated with the scale-up of EMx™ were presented in detail Section 4.4.1. Although not demonstrated on large turbines,

because some agencies have considered EMx™ to be an available option, it will be further evaluated for this project.

Step 2: Eliminate Technically Infeasible Options
Turbine and Duct Burner Normal Operation CO Analysis

Oxidation catalysts and combustion controls are technically feasible for this project.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Turbine and Duct Burner Normal Operation CO Analysis

To rank the control technologies, it is necessary to estimate the level of control each technology offers. The GE Frame 7FA turbines to be used for the Bowie project have a maximum uncontrolled exhaust CO concentration of 7.7 ppmv at 15% O_2 from the turbines. The turbines and duct burners combined will have a maximum uncontrolled emission concentration of 15.5 ppmv at 15% O_2. The Bowie turbines equipped with oxidation catalysts will achieve a CO exhaust concentration of 2.0 ppmv at 15% O_2 on a 1-hour average. The control technology ranking for the CO BACT analysis is shown in Table 4-4.

Table 4-4. CO Control Technology Emission Rate Ranking

Control Technology	CO Emissions (ppmv)[a]	CO Emissions (tpy)[b]	Reduction from Uncontrolled (tpy)
Oxidation catalyst	2.0	161.1	315.6
Combustion controls (no add-on control)	15.5	476.7	NA

[a] Emission concentration for each turbine and duct burner pair during normal operation.
[b] Emissions for two turbine and duct burner pairs on an annual basis including startup, shutdown, and tuning emissions.

Notes:

CO	=	Carbon monoxide
NA	=	Not applicable
ppmv	=	Parts per million by volume
tpy	=	Tons per year

As indicated previously, although EMx™ has not been demonstrated on large turbines, many regulatory agencies have treated it as available and it will be evaluated in the remaining steps of this analysis. CO control using EMx™ is comparable to the use of an oxidation catalyst. The difference is that EMx™ uses a chemically modified catalyst so that it also removes NO_x. The chemical modifications are not believed to affect the CO reduction performance and its ability to control CO is expected to be similar to that of an oxidation catalyst (Alpha-Gamma Technologies, Inc. 2000). As such, if EMx™ were demonstrated in practice on large turbines, it would appear in Table 4-3 in the same position as the oxidation catalyst, with a control concentration of 2.0 ppmv at 15% O_2 and a reduction from uncontrolled emissions of 315.6 tpy.

Step 4: Evaluate Most Effective Controls and Document Results
Turbine and Duct Burner Normal Operation CO Analysis

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The top technologies are oxidation catalysts and EMx™.

There are environmental and energy impacts associated with the use of oxidation catalysts. As with other add-on control devices, there are energy impacts associated with oxidation catalysts. The increased backpressure in the turbine that results from adding the catalyst increases the heat input required and reduces the peak power output of the turbine. A typical increase in backpressure from the oxidation catalyst panels for a frame-size turbine is approximately 1 inch (ICCR 1998a). Using the rule of thumb energy penalties of 0.15% per inch heat rate penalty and 0.15% per inch peak power penalty discussed in Section 4.4.1, this results in a heat input penalty of 0.15% and a peak power penalty of 0.15%.

Oxidation catalysts generate GHG emissions by converting CO to CO_2. The oxidation catalyst will produce up to 248 tons per year of CO_2 from each Bowie turbine and duct burner.

Disposal of the spent catalysts could represent an environmental impact. The catalysts used must be replaced every three to six years. The catalyst contains heavy metals that may cause the spent catalyst to be considered a hazardous waste. However, catalyst vendors typically accept return of spent catalysts for recovery and reuse of the catalysts' precious metals and the environmental impact is mitigated.

The energy, environmental, and cost impacts associated with the use of EMx™ were described in Section 4.4.1 of this document. They are:

- Heat input penalty of 0.60%-0.90% due to increased backpressure;
- Peak power penalty of 0.60%-0.90% due to increased backpressure;
- Energy loss due to steam consumption for catalyst regeneration;
- Use of natural gas to produce hydrogen rather than electricity;
- CO_2 emissions;
- Possible H_2S emissions; and
- High annual costs at $6,979,127 per year.

Step 5: Select BACT
Turbine and Duct Burner Normal Operation CO Analysis

The final step in the top-down BACT analysis process is to select BACT. Both oxidation catalysts and EMx™ can achieve the same emission limit and both have associated energy and environmental costs. The energy impacts are greater for EMx™ and EMx™ also has associated cost impacts relative to oxidation catalysts. Oxidation catalysts are proposed as the BACT technology for this project. EMx™ is not chosen because of the uncertainties related to scale-up of the system to large turbines.

The BACT emission limit of 2.0 ppmvd at 15% O_2 on a 1-hour average proposed for the Bowie project has been compared to other emission limits imposed on similar projects. EPA's RBLC, EPA's turbine spreadsheet, information on projects permitted in California, and information available from other air quality regulatory agencies have been reviewed to compile a listing of turbine CO emission limits. This listing is provided in Appendix D. The majority of BACT emission limits issued for frame-size combustion turbines is 2 ppmv at 15% O_2 on a 1-hour average. Emission limits for the six projects identified with emission limits less than 2 ppmv at 15% O_2 are shown in Table 4-5.

Table 4-5. CO BACT Emission Limits Less than 2.0 ppmvd at 15% O_2

Project	Emissions Limit Less than 2.0 ppmvd	Notes
Kleen Energy Systems, LLC	0.9 - without duct firing 1.7 - with duct firing	Operations began early May 2011
Avenal Power Center LLC	1.5 – without duct firing	Limit with duct firing is 2.0 ppmvd
Palmdale Hybrid Power Project	1.5 – without duct firing does not apply during 3-year demonstration period	Limit with duct firing is 2.0 ppmvd
Virginia Electric and Power Company – Brunswick Plant	1.5 – without duct firing	Limit with duct firing is 2.4 ppmvd
Virginia Electric and Power Company – Warren County Facility	1.5 – without duct firing	Limit with duct firing is 2.4 ppmvd
Southern Company/Georgia Power, Plant McDonough	1.8	3-hour averaging period

Notes:
ppmvd = Parts per million by volume dry
LAER = Lowest achievable emission rate

As indicated in Table 4-5, the limits below 2 ppmvd at 15% O_2 for several of these facilities are for operation without duct firing. The CO limits for Avenal Power Center LLC and Palmdale Hybrid Power Project with duct firing are 2.0 ppmvd at 15% O_2. The limits without duct firing for these projects do not have to be met for the first three years of operation. The CO limits for the Virginia Electric and Power Company, Warren County Facility, and Brunswick Plant with duct firing are 2.4 ppmvd at 15% O_2.

The CO emission limit for the Southern Company/Georgia Power, Plant McDonough project is 1.8 ppmv at 15% O_2 on a 3-hour average. With the longer averaging period, this limit is not appreciably more stringent than the 2 ppmv limit on a 1-hour average proposed for the Bowie project.

In 2002, Kleen Energy Systems, LLC (Kleen Energy) submitted a permit application to the Connecticut Department of Environmental Protection, Bureau of Air Management for a combined-cycle combustion turbine project to be located in Middletown, Connecticut. The project consists of two dual fuel Siemens SGT6-5000F combustion turbines, a heat recovery steam generator, and 445 million British thermal units per hour (MMBtu/hr) duct burners. In its permit application, Kleen Energy proposed a BACT limit of 1.8 ppmv at 15% O_2 for natural gas combustion. The BACT analysis included no discussion of energy or economic impacts associated with the use of oxidation catalysts and the only environmental impact mentioned was the tendency of SO_2 to oxidize to SO_3 with the use of fuel oil. In 2006, Kleen Energy submitted updated BACT analyses for the project. The CO BACT analysis was unchanged.

In 2007, the Connecticut Department of Environmental Protection (Connecticut DEP), Bureau of Air Management prepared an engineering evaluation for the Kleen Energy project and selected CO BACT levels for natural gas combustion of 0.9 ppmvd at 15% O_2 without duct firing and 1.7 ppmvd at 15% O_2 with duct firing. The engineering analysis did not include any discussion of environmental, energy, or economic impacts associated with CO control. A New Source Review (NSR) permit was issued for the project on February 25, 2008 (CDEP 2007) and contained the emission limits included in the state's engineering evaluation (CDEP 2008).

Following issuance of the Kleen Energy permit, at least 30 permits were issued for natural gas-fired, combined-cycle turbine projects with CO BACT limits of 2 ppmvd at 15% O_2 or higher (see Appendix D). In several cases the permitting authority considered the Kleen Energy permit limits as

outliers. In others, because the facility had yet to be constructed or had only been operating for a short time, the lower limits were determined not to have been demonstrated in practice.

The Kleen Energy project turbines started up in early May 2011. Following startup of the project, EPA Region 9 issued permits for the Avenal Power Center LLC and Palmdale Hybrid Power Projects with BACT limits of 1.5 ppmv at 15% O_2, but the permits do not require compliance with the lower limits for three years. The delay in compliance with the lower limits was because of the lack of long-term compliance data demonstrating achievement of the lower limits (EPA 2011a and EPA 2011b). The oxidation catalysts used to control CO have a useful life of three to five years. Control is highest when the catalyst is new. As the catalyst ages, control becomes less efficient. To be demonstrated in practice, an emission limit below 2 ppmv at 15% O_2 would need to be met for at least three years.

To achieve an emission limit less than 2 ppmv at 15% O_2 requires the installation of more catalyst than that needed to meet a limit of 2 ppmv at 15% O_2. EPA Region 9 did not review the additional energy and economic costs associated with the use of additional catalyst. As discussed previously, oxidation catalysts increase the backpressure on the turbine increasing the heat input required to produce power and reducing the peak power output of the turbine. The increase in required heat input increases as catalyst is added and the decrease in peak power output of the turbine decreases with increased catalyst. The additional catalyst material also increases the cost of the control system, the cost of periodic catalyst replacement, the cost of fuel, and decreased revenue from decreased peak power output.

In 2009, Connecticut DEP, the same agency that permitted the Kleen Energy project with emission limits less than 2 ppmvd, agreed to a BACT recertification for Towantic Energy, LLC with a turbine CO limit of 2.0 ppmvd for natural gas combustion. Towantic Energy, LLC had received a permit in 2004 for a project with two combined-cycle GE Frame 7FA combustion turbines without duct firing. The original permit contained a CO BACT limit of 5.0 ppmv at 15% O_2. As the project was not constructed within three years of permit issuance, BACT recertification was required. The BACT recertification submitted for the project contained a CO BACT level of 2 ppmv at 15% O_2. The recertification application included energy and cost impact information for meeting either a 1.3 ppmv at 15% O_2 limit or a 0.9 ppmv at 15% O_2 limit (Towantic 2008). An incremental cost effectiveness of more than $7,000 per ton for a limit of 1.3 ppmv at 15% O_2 and a reduction in net power output capacity of 18 kilowatts (kW) were estimated and an incremental cost-effectiveness of $27,000 and a reduction of net power output capacity of 50 kW were estimated for a limit of 0.9 ppmv at 15% O_2. Based on the information provided, Connecticut DEP agreed to the proposed CO BACT limit of 2 ppmv at 15% O_2 (CDEP 2009).

In 2010, the Virginia Department of Environmental Quality (VDEQ) considered oxidation catalyst cost information for reducing the BACT limit with duct firing below 2.4 ppmv at 15% O_2 submitted for the Virginia Electric and Power Company, Warren County Facility. Virginia determined that it was not cost effective to require a lower CO limit (VDEQ 2010).

In 2013, the Bay Area Air Quality Management District (BAAQMD) re-issued a non-PSD permit for the Oakley Generating Station Project, a natural gas-fired, combined-cycle combustion turbine project proposing to use GE Frame 7FA, Model 5 turbines. Although the permit was not a PSD permit, BAAQMD regulations require a BACT analysis. BAAQMD reviewed the economic impacts associated with a CO limit of less than 2 ppmv at 15% O_2 and noted the associated energy impacts. BAAQMD determined that a limit below 2ppmv at 15% O_2 was not cost effective (BAAQMD 2013a).

Each agency that has considered energy and cost impacts associated with a CO BACT limit below 2.0 ppmvd for natural gas combustion in combined cycle turbine system has determined that such a limit is not warranted. As a result, a CO BACT limit of 2.0 ppmvd at 15% O_2 is proposed as BACT for the Bowie turbines.

A BACT limit must not be higher than an applicable NSPS emission limit. The requirements of 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply to the turbines; however, the subpart does not include an applicable CO limit.

Note that the proposed CO BACT limit is for normal operations only and cannot be achieved during startup, shutdown, or tuning. As BACT must be applied at all times and the normal operation emission limit is not achievable during other operating modes, a separate BACT analysis is required for startup, shutdown, and tuning. That analysis is provided in Section 4.4.4 of this document.

4.4.3 Turbine and Duct Burner Normal Operation $PM/PM_{10}/PM_{2.5}$ Analysis

For the turbines and duct burners it has been assumed that all of the particulate matter emissions will be $PM_{2.5}$. A single analysis will therefore be conducted for PM, PM_{10}, and $PM_{2.5}$. According to GE (GE 2009), particulate matter emissions from natural gas-fired turbines are from ambient PM that passes through the turbine inlet air filters, inert solids in the fuel gas supply, construction debris, and metallic rust or oxidation products.

Step 1: Identify All Control Technologies Turbine and Duct Burner Normal Operation $PM/PM_{10}/PM_{2.5}$ Analysis

Five control methods for the combustion devices have been identified for $PM/PM_{10}/PM_{2.5}$ control:

- Electrostatic precipitators (ESPs);
- Scrubbers;
- Fabric filters;
- EMx™ ; and
- Combustion of natural gas.

EmeraChem, the supplier of EMx™, a post-combustion catalytic oxidation and absorption system discussed in Sections 4.4.1 and 4.4.2 of this application, has been marketing the control system as an option for PM control as well as NO_x and CO control. No regulatory agency has yet verified that the control system is a viable option for PM control and no agency has yet considered it a technically feasible PM control technology in a BACT analysis. EMx™ has only been used on small turbines for NO_x and CO control and has never been demonstrated on large frame-size turbines like those to be used at the Bowie Power Station. Concerns about the technical issues associated with the scale-up of EMx™ were presented in detail Section 4.4.1. Given that EMx™ has not been proven as a viable PM control technology and that it has not been demonstrated on large turbines, EMx™ is not considered an available PM control option for the Bowie project.

Step 2: Eliminate Technically Infeasible Options Turbine and Duct Burner Normal Operation $PM/PM_{10}/PM_{2.5}$ Analysis

ESPs, scrubbers, and fabric filters are not considered to be technically feasible options for gas turbines because of the high exhaust flow rates and low particulate matter loading associated with turbine exhaust. In addition to the flow rate and loading problems, the particle resistivity associated with gas turbine exhaust is a problem for ESPs. ESPs remove particles by charging the particles and then collecting them on plates. ESP performance is greatly affected by the ability of particles to accept and maintain a charge. Because of the resistivity of the exhaust particles from gas turbines, ESPs are not effective for turbine PM control.

Step 5: Select BACT
Turbine and Duct Burner Normal Operation $PM/PM_{10}/PM_{2.5}$ Analysis

As a result of the top-down analysis, the only remaining control method is the use of natural gas; therefore, Steps 3 and 4 are unnecessary and the use of natural gas is chosen as the basis for BACT for this project. This decision is consistent with the decisions contained in the RBLC for particulate matter emissions associated with natural gas-fired combustion turbines. Information from the RBLC, EPA's turbine spreadsheet, and information on projects permitted in California are provided in Appendix D and show that add-on controls for PM have not been required for any natural gas-fired combustion turbine project.

A total (combined filterable and condensable) $PM/PM_{10}/PM_{2.5}$ limit of 8.5 pounds per hour (lb/hr) is proposed for each Bowie project turbine and duct burner pair. PM emission limits issued to other similar turbines have been reviewed to determine if this limit represents BACT for this project and are presented in Appendix D.

The lowest lb/hr BACT limits for combined-cycle turbines with duct burners identified are:

- Caithness Blythe II, LLC – 6.0 lb/hr;
- Russell City - 7.5 lb/hr; and
- Klamath Generation LLC – 0.0042 pounds per million British thermal units (lb/MMBtu) (highest Bowie emission rate is 0.0044 lb/MMBtu).

The Blythe II project was permitted in 2007, but construction has not begun and the project is on hold. The Russell City project recently began operations. That project includes duct burners rated at 200 MMBtu/hr heat input. The Klamath Generation LLC project has 250 MMBtu/hr duct burners. The Bowie project duct burners are larger, with a heat input rating of 420 MMBtu/hr. The proposed Bowie emission limit is higher than the limits imposed on these projects to account for the larger duct burners.

The proposed $PM/PM_{10}/PM_{2.5}$ limit of 8.5 lb/hr (combined filterable and condensable) for each Bowie turbine and duct burner pair is comparable to other recently permitted projects and is proposed as BACT.

A BACT limit must not be higher than an applicable NSPS emission limit. The requirements of 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply to the turbines; however, the subpart does not include an applicable PM, PM_{10}, or $PM_{2.5}$ limit.

The proposed BACT limit can be met during all turbine operating conditions, including startup, shutdown, and tuning, making a separate BACT analysis for those conditions unnecessary for PM, PM_{10}, and $PM_{2.5}$.

4.4.4 Turbine and Duct Burner Startup, Shutdown, and Tuning Analysis

The proposed NO_x and CO BACT emission limits for normal operation of the turbines cannot be met during periods of startup, shutdown, and tuning. Turbine tuning occurs primarily after routine maintenance when the turbine is tested at various incremental loads, during which the emission controls may not be operating and emissions are often similar to those associated with cold startup.

Startup sequences for combined-cycle combustion turbines are specified by the equipment vendors and include multiple steps in which the equipment power output is gradually increased until normal operating conditions are reached. The combustion turbine's speed and load are carefully increased as the HRSG, steam drums, steam piping, emissions control equipment, steam turbine, and

other equipment are heated and brought to a stable operating condition. The gradual increase is necessary to protect personnel and equipment and to maintain equipment warranties.

One of the primary reasons that normal operation emission limits cannot be met during startup, shutdown, and tuning is that the DLN system cannot be operated at low loads. To ensure proper function at normal operating loads, the injector nozzles connecting the premixing chamber to the combustion chamber must be large enough to ensure that the fuel-air mixture flows into the combustion chamber at the proper rate. During startup, shutdown, and tuning when the turbine is not at an operational load, the low fuel flow from the nozzles is insufficient to prevent the flame wall in the combustion chamber from backing up into the premixing chamber. To avoid the risk of fuel blowback, which could cause the premixing chamber to overheat, the premixing chamber must be bypassed when the unit is in startup, shutdown, or tuning mode. When the premixing chamber is bypassed, the turbine operates like a standard single-stage diffusion flame turbine.

In addition to the startup requirements of the turbine, the NO_x and CO control equipment do not provide control, or provide only partial control, when the exhaust temperatures are not at optimum levels. Until the optimal exhaust temperature range for the controls is reached and the catalysts are at operating temperature, the control devices do not operate at design levels. As such, during the periods of highest emissions, the DLN system is not operating to minimize emissions and the emission control systems are not capable of efficiently controlling the emissions that are generated.

As these conditions are part of the expected operation of the turbines, the requirement to meet BACT still applies. As the normal operation BACT emission limits cannot be met, a BACT analysis specifically for these conditions is required for the turbines for NO_x and CO, taking into account the conditions that exist during startup, shutdown, and tuning.

Generation of NO_x and CO emissions from combustion are interrelated. Higher combustion temperatures lead to more complete combustion and lower CO emissions, but produce higher NO_x emissions. Conversely, lower temperatures reduce the generation of NO_x, but the associated incomplete combustion yields higher CO emissions. Because emission control equipment performance is diminished during startup, shutdown, and turning, the generation of emissions during these operating conditions will influence the BACT analysis to a greater extent than during normal operations. As such, the BACT analyses for NO_x and CO have been combined for startup, shutdown, and tuning.

Step 1: Identify All Control Technologies
Turbine and Duct Burner Startup, Shutdown, and Tuning Analysis

The following control options have been identified as possible strategies for reducing emissions during startup, shutdown, and tuning:

- Fast start design such as Siemens Flex Plant™ 30 and GE's Rapid Response;
- Low load turn-down technology, GE's OpFlex™; and
- Work practices.

Total emissions during startup, shutdown, and tuning are a factor of the emissions generated and emitted and the length of the event. One of the primary reasons that combined-cycle turbines cannot start up faster is the need to slowly heat the thick-walled steam drum in the steam generator for safety and reliability purposes. Steam drum re-designs that eliminate the steam drum or use once-through steam technology, and designs using a steam drum with thinner walls have been developed to reduce startup times. In addition, fast start designs decouple the combustion turbine from the steam turbine during the early phases of startup, reducing low load, higher emission combustion turbine operation. These designs

allow power plant operators to maximize energy production, but have the collateral benefit of reducing startup emissions by reducing startup times.

Siemens has developed a fast start combined-cycle turbine design using once-through steam technology. Conventional combined-cycle turbine facilities use a steam drum in the steam generator to contain the steam before it is introduced to the steam turbine. Once-through steam boiler technology replaces the steam drum with external steam separators and surge bottles so that startup can proceed more rapidly.

The Siemens once-through steam boiler design is called Fast Start and is used in integrated plant designs referred to as Flex Plant™ 10 and Flex Plant™ 30. Flex Plant™ 10 is optimized primarily for peaking plants. A more energy efficient design suitable for base-load plants is referred to as Flex Plant™ 30.

The only project operating with a Flex Plant™ 30 turbine is the Northern California Power Agency's Lodi Energy Center. The Lodi Energy Center has a one on one configuration (one combustion turbine and one steam turbine) and began operation in November 2012. Although the fast start technology is expected to reduce start times considerably, the permit issued by the San Joaquin Valley Air Pollution Control District (SJVAPCD; SJVAPCD 2010) for the Lodi Energy Center contains an initial duration limit for startups and shutdowns of 3.0 hours and requires that within 15 months following commissioning the owner of the project, the Northern California Power Agency propose new startup durations based on data collected during the 12 month period following commissioning. As such, the Flex Plant™ 30 turbine is in a demonstration period for startup durations.

In January 2013, a request for a permit modification to raise the Lodi Energy Center turbine CO emission limit during startup was submitted (NCPA 2013). The requested increase was necessary as under certain conditions, primarily cold ambient temperatures and after the turbine had been shut down for many hours, the startup CO emissions were higher than expected. The permit was modified in June 2013, raising the CO emission limit during startup from 900 lb/hr to 1500 lb/hr (SJVAPCD 2013).

Flex Plant™ 30 has been proposed for two additional projects in California, the Blythe Energy Project Phase II and the Huntington Beach Energy Project. Construction on the Blythe Energy Project Phase II project has not begun and permitting of the Huntington Beach Energy Project has not yet been completed.

As the Lodi Energy Center has not yet completed the 12-month demonstration period allowed by the SJVAPCD, and the currently permitted startup duration is almost as long as a conventionally designed facility, Flex Plant™ 30 has not been demonstrated in practice and is not yet an available technology.

GE has developed a power plant system design to reduce combined-cycle turbine plant startup in part by re-designing the steam drum. The modified steam drum has a thinner wall thickness achieved by elongating the steam drum and reducing its diameter. The design is referred to as Rapid Response. It requires a specially designed HRSG and steam turbine. It uses an auxiliary boiler to assist in heating the steam turbine during startup. The concepts used by GE for the Rapid Response design are not new or proprietary and are being used by engineering and energy firms to develop fast start designs using GE turbines. A fast start design by Kiewit Power Engineers Co. using GE turbines is planned for the Bowie project.

There are no currently constructed or operating GE turbine systems with fast start technology. GE turbines with fast start technology are proposed for three projects in California, the Victorville 2 Hybrid Power Project (EPA 2010a), the Palmdale Hybrid Power Project (Palmdale 2011), and the Oakley Generating Station (BAAQMD 2013). According to the California Energy Commission website, construction start dates for the Victorville 2 Hybrid Power Project and the Palmdale Hybrid Power Project

have not yet been determined; a construction start of 2011 is listed for the Oakley Generating Station with a scheduled on-line date of 2017.

As a GE turbine system with fast start technology has not yet been constructed, this technology has not yet been demonstrated in practice and is not considered an available technology for BACT purposes. Such a design is being proposed for the Bowie Power Station as a beyond BACT option.

Low load turn-down technology is a software solution that was developed to enable turbines to operate efficiently at lower loads. GE has a commercially available technology called OpFlex™ that uses a proprietary method of controlling fuel distribution. GE has adapted this technology for startup, calling it OpFlex™ Start-up NO_x and Start-up Fuel Heating. It is designed to relax the fuel temperature requirements such that the rated fuel temperature is required later in the startup sequence, reducing or eliminating the hold associated with fuel temperature. This enables a faster start.

GE will not guarantee any specific emission reduction for OpFlex™ Start-up NO_x and Start-up Fuel Heating (BAAQMD 2008 and BAAQMD 2010b). As the manufacturer will not guarantee the performance of the system, there is no certainty that the predicted emission reductions can be achieved. As such, this technology is not considered an available option.

Step 5: Select BACT
Turbine and Duct Burner Startup, Shutdown, and Tuning Analysis

As a result of the top-down analysis, the only remaining control method is the use of work practices. Therefore, Steps 2 through 4 are unnecessary. If Bowie Power Station, LLC was not proposing a beyond BACT option for reducing emissions, work practices would be the sole basis for BACT.

The beyond BACT technology combination to be used for the project is the use of fast start technology and work practice standards to minimize emissions from startup, shutdown, and tuning.

Work practices that will be used for startup are:

- Following plant equipment manufacturer and engineering design recommendations;
- Injecting ammonia as soon as possible; and
- Bringing the turbine load to the point that the normal operation NO_x and CO emission limits can be met as quickly as possible, consistent with the equipment vendors' recommendations and safe operating practices.

During shutdown, the load would be reduced to zero as quickly as possible consistent with safe operating practices and equipment vendors' recommendations and ammonia injection to the SCR system would be maintained as long as the system remains above the minimum SCR operating temperature.

As a beyond BACT option has been selected for the project, a comparison of the emission limits proposed for the Bowie project to limits demonstrated by constructed and operating projects without fast start technology would provide no insight into appropriate emission limits for the project. However, as indicated previously, the Lodi Energy Center is operating a turbine designed with fast start capability in a demonstration phase and there are several projects planning to use fast start technology that have been permitted or are in the permitting process. A review of emission values associated with these projects can be made.

Even with a limited number of project emission values to review, emission limits for startup, shutdown, and tuning are extremely difficult to compare for a number of reasons. These include: the unique nature of startups for combined-cycle turbines, the definition of startup and shutdown, the delineation of types of startup, ambient conditions associated with the limits, and the form of the emission limits.

Startup is a function of integrated plant performance. Factors influencing startup include the turbine model, HRSG manufacturer and model, steam turbine manufacturer and model, plant distributed control system, configuration (arrangement and number of combustion and steam turbines), and other plant features. Vendors do not guarantee startup, shutdown, and tuning emissions. These emissions are based on vendor estimates, engineering calculations, and the risk the operator is willing to accept. In addition, regulatory factors such as the need and cost to obtain offsets for NO_x emissions in nonattainment areas or other jurisdictions with offset requirements have driven operators to agree to optimistic startup emission limits.

Ambient temperature and humidity influence turbine emissions including emissions during startup, shutdown, and tuning. It would seem that emission limits for these special operating conditions would be based on the worst-case ambient conditions; however, this may not be the case and would vary by location.

The form of startup, shutdown, and tuning emission limits (mass per time, mass per event, average emission rate during event) varies considerably. Limits on the total mass emissions during an event are more comparable than limits expressed in other forms, with less uncertainty that different types of limits are being compared. Mass per event limits are available for the projects for which fast start designs are proposed, but are not available for the Lodi Energy Center. The event limits for the proposed projects are shown in Table 4-5. During the demonstration period, following modification of the CO limit in the permit, the Lodi Energy Center duration for all startup and shutdown events is limited to three hours and emissions are limited to: NO_x – 160.00 lb/hr and CO - 1,500.00 lb/hr.

As shown in Table 4-6, durations and emissions for startups and shutdowns vary considerably, and the validity of direct comparisons is questionable. However, the limits proposed for the Bowie turbines are within the range of the limits proposed for other projects that have selected a fast start design.

The following are proposed as BACT limits for the Bowie Station for turbine startup, shutdown, and tuning:

- Hot Start: occurs if a turbine system has been offline for less than 8 hours

  NO_x – 50.7 lb/turbine/event

  CO – 131.1 lb/turbine/event

- Warm Start: occurs if a turbine system has been offline for 8 hours to 72 hours

  NO_x – 78.9 lb/turbine/event

  CO – 145.0 lb/turbine/event

- Cold Start: a cold start occurs if a turbine system has been offline 72 hours or longer

  NO_x – 78.9 lb/turbine/event

  CO – 145.0 lb/turbine/event

- Tuning: while cold starts will be completed in a maximum of 60 minutes, tuning times will be variable so proposed BACT limits are on a lb/hr basis

  NO_x – 78.9 lb/turbine/hr

  CO – 145.0 lb/turbine/hr

- Shutdown

  NO_x – 16.4 lb/turbine/event

  CO – 51.5 lb/turbine/event.

Table 4-6. Startup, Shutdown, and Tuning Emission Limits[a]

Event	Project	Bowie Power Station	Blythe Energy Project Phase II	Huntington Beach Energy Project	Oakley Generating Station	Palmdale Hybrid Power Project	Victorville 2 Hybrid Power Project
Hot Starts	NO_x (lb/event)	50.7	81.9	16.6	22.3	40	40
	CO (lb/event)	131.1	58.5	33.6	85.2	329	329
	Duration (minutes)	30	60	32.5	60	80	78
Warm Starts	NO_x (lb/event)	78.9	81.9	16.6	22.3	40	40
	CO (lb/event)	145.0	58.5	46.0	85.2	329	329
	Duration (minutes)	60	60	32.5	60	80	78
Cold Starts and Tuning	NO_x (lb/event)	78.9	120.9	28.7	96.3	96	96
	CO (lb/event)	145.0	140.4	116	360.2	410	410
	Duration (minutes)	60	180	90	120	110	108
Shutdown	NO_x (lb/event)	16.4	29.7	9.0	39.3	57	57
	CO (lb/event)	51.5	25.3	45.3	140.2	337	337
	Duration (minutes)	15	60	1.0	60	30	30

[a] Lowest value in each row is shaded.

Notes:

CO = Carbon monoxide
lb = Pounds
NO_x = Oxides of nitrogen

Startup is proposed to be defined as "setting in operation of a turbine to the point that the control equipment has reached operating temperature and normal operation emission limits can be met." Shutdown is proposed to be defined as "from the point at which the combustion turbine load falls below the point at which the normal operation emission limits can be met to a point where the fuel supply can be cut off from the turbine."

4.4.5 Turbine and Duct Burner GHG Analysis

The BACT analysis for GHG emissions from the turbines and duct burners is presented below.

Step 1: Identify All Control Technologies Turbine and Duct Burner GHG Analysis

EPA has issued a document titled *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA 2011c; EPA guidance document). The current version of the document is dated March 2011.

References provided in the EPA guidance document were consulted to identify GHG emission technology options. Two areas of power plant GHG emission reduction measures were identified:

- Carbon capture and sequestration (CCS); and
- Energy-efficiency measures.

The EPA guidance document indicates that CCS should be listed in Step 1 of the BACT analysis for large CO_2-emitting facilities (EPA 2011c). CCS involves capturing the GHGs, transporting them to a suitable storage location, and storing them securely in geologic reservoirs. CCS is an attractive option as emissions could be reduced substantially without changing the energy supply infrastructure. CO_2 is already captured in the petroleum and petrochemical industries and several gas-fired and coal-fired electric generating stations capture a small slipstream of CO_2 for sale as a commodity. Underground storage of CO_2 has taken place as a byproduct of the injection of CO_2 into oil fields for enhanced oil recovery (EOR).

Efficient power generation minimizes GHG emissions by minimizing the amount of fuel combusted. Combined-cycle turbine facilities are the most efficient commercial technology for central station power generation (EPA 2008a). Combined-cycle turbine system efficiency is influenced by a number of factors including turbine design and configuration.

Step 2: Eliminate Technically Infeasible Options Turbine and Duct Burner GHG Analysis

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. Options that are technically infeasible for the project are eliminated.

CCS

There are three primary components to CCS: capture, transport, and storage. The feasibility of each of these components for the Bowie Power Station turbines and duct burners is examined below.

CCS — Capture

The first CCS step is GHG capture. The goal of GHG capture is to produce a concentrated stream of GHGs that can be transported to a sequestration site. Several technologies in various stages of development exist for GHG capture. They can be divided into three approaches: pre-combustion capture, oxyfuel, and post-combustion capture.

Pre-combustion capture uses a gasification plant to convert the fuel to hydrogen and CO_2. The CO_2 can then be separated from the hydrogen fuel prior to combustion. This option is primarily being considered for coal in integrated gasification combined-cycle plants.

Oxyfuel or oxy-combustion uses nearly pure oxygen in the combustion process rather than air. This produces an exhaust stream that is primarily water and CO_2. The high concentration of CO_2 in the flue gas can then be captured. According to the Intergovernmental Panel on Climate Change (IPCC), this technology is only in the demonstration phase (IPCC 2005). In a 2009 study prepared for the Clean Air Strategic Alliance (Alberta, Canada) titled "Electricity Framework 5 Year Review — Control Technologies Review," the timeframe for this technology to be available on a commercial scale is 2017-2020 (Clean Air Strategic Alliance 2009).

Post-combustion capture separates GHGs from the exhaust stream. There are several process technologies that can be used for CO_2 capture. While post-combustion capture options are further developed for large-scale use than the other capture options, the scale of these systems is still

considerably smaller than what is needed for a power plant, and there are difficulties in applying CO_2 post-combustion capture to power plants. These result from:

- Low pressure and dilute GHG concentrations in the exhaust (only 3%-4% by volume in exhaust from gas-fired turbines) require a high volume of gas to be treated;
- Trace impurities, such as NO_x, reduces the effectiveness of CO_2 adsorbing processes; and
- Compressing CO_2 from atmospheric pressure to pipeline pressure requires a large amount of energy

(National Energy Technology Laboratory [NETL] 2013 and Interagency Task Force [ITF] 2010).

Much of the research into addressing these issues is focused on capture of GHG emissions from coal-fired power plants. This is because coal combustion produces about twice as much CO_2 as natural gas combustion (EPA 2013c).

CCS — Transport

The second CCS component is transport to the sequestration site. CO_2 has been transported in pipelines in the United States for nearly 40 years and there are 3,600 miles of existing CO_2 pipelines (ITF 2010). The nearest CO_2 pipeline to the Bowie Power Station site is the Cortez pipeline that carries naturally occurring CO_2 from the McElmo Dome field near Cortez, Colorado to the CO_2 hub near Denver City, Texas for EOR. The nearest approach of this pipeline is more than 350 miles from the Bowie Power Station site.

Kinder Morgan CO_2 Company, LP, which owns an interest in the pipeline, is considering transporting captured CO_2 to a sequestration site as a possible future use of the pipeline (Havens 2008). There are several issues associated with this usage that would require resolution, including mixing gases from CO_2 capture with the CO_2 currently carried in the pipeline, which must meet quality specifications, as well as regulatory issues, liability issues, and the lack of a developed sequestration site.

CCS — Storage

The final CCS component is the storage of CO_2 in subsurface formations. Natural CO_2 formations known to have contained CO_2 over geologic time indicate the feasibility of engineered storage (ITF 2010) and injection of CO_2 into geologic reservoirs for EOR has occurred for many years. The Department of Energy (DOE) created a network of seven Regional Carbon Sequestration Partnerships to help develop "the technology, infrastructure, and regulations to implement large-scale CO_2 sequestration in different regions and geologic formations within the Nation" (NETL 2013). Arizona is part of the West Coast Regional Carbon Sequestration Partnership and the Southwest Carbon Partnership.

Work by the partnerships is being conducted in three phases. Phase I was the Characterization Phase during which the partnerships identified opportunities for carbon sequestration. In Phase II, the Validation Phase, multiple small scale field tests were conducted. The partnerships are now into Phase III, the Development Phase, which involves large-volume sequestration tests. DOE's NETL expects the results to "provide the foundation for CCS technology commercialization throughout the United States, including providing input that can be used in demonstration projects" (NETL 2011). The Development Phase is scheduled to last at least 10 years.

CCS — Feasibility Determination

CCS is not a feasible GHG control option for the Bowie Power Station turbines and duct burners as there are issues with each of the three CCS components.

No pre-combustion, oxyfuel, or post-combustion technology is currently demonstrated to capture GHG emissions at the scale needed for a combined-cycle combustion turbine plant. In February 2010, President Obama established an ITF chaired by EPA and DOE. In August 2010, ITF issued a report that assessed current capture technologies as "not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application" (ITF 2010). In addition, in reviewing natural gas processing facilities that currently capture the largest volume of CO_2, ITF states, "the degree to which experience with natural gas processing is transferrable to separation of power plant flue gas is unclear, given the significant differences in the chemical make-up of the two gas streams" (ITF 2010).

The EPA guidance document states that "if a control option has been demonstrated in practice on a range of exhaust gas streams with similar physical and chemical characteristics … it may be considered as potentially feasible for application to another process" (EPA 2011c). ITF has identified that differences in chemical make-up between the gas streams upon which demonstrated CO_2 capture technology has been applied and power plant flue gas are an uncertainty in the technical transfer of the technology.

CO_2 transport is also problematic. While there are no technology barriers to CO_2 transport through pipelines, the pipeline infrastructure currently does not exist in southeastern Arizona. Although a pipeline for transporting captured CO_2 from the Bowie turbines and duct burners could be constructed, there is no commercial-scale sequestration facility in which to store the CO_2. There are seven DOE-funded large-scale field tests getting underway by the Regional Partnerships throughout the country, but a commercial sequestration site is many years away.

Capture technology has not yet been demonstrated, transport infrastructure is lacking, and a commercially available storage site is many years away. As a result, CCS is still in a developmental stage and not yet available for controlling power plant GHG emissions. This current state of CCS for GHG emissions from power plants is confirmed in a statement made by EPA in the Advanced Notice of Proposed Rulemaking for the GHG Tailoring Rule in the discussion of potential options for regulating GHGs under the Clean Air Act: "… where critical new control strategies, such as carbon capture and storage, are still in the early stages of development" (75 FR 44485). CCS technology is not an available option for control of GHG emissions from the Bowie Power Station turbines and duct burners and is eliminated from this BACT analysis.

Energy Efficient Power Generation

Energy efficient power generation is an available option for the Bowie Power Station turbines and duct burners.

Step 5: Select BACT
Turbine and Duct Burner GHG Analysis

The only remaining control option for the turbines and duct burners is energy efficient power generation. Steps 3 and 4 of the top-down BACT method are not applicable and efficient generation is selected as the basis for GHG BACT for the Bowie Power Station combustion turbines and duct burners.

To determine the appropriate BACT level associated with efficient generation, the efficiency of the Bowie Power Station combined-cycle combustion turbine plant was compared to the efficiency of other similar facilities. To accurately compare combined-cycle combustion turbine plant efficiencies, the basis of the efficiency values must be the same. The most critical aspects of the basis for combined-cycle combustion turbine plant efficiency include:

- Fuel Basis: The fuel basis for the efficiency can be on a lower heating value (LHV) basis or a higher heating value (HHV) basis. Typically, combustion turbine efficiency has been discussed on an LHV basis. The EPA guidance document indicates a preference for the use of HHV.
- Ambient Conditions: Combustion turbine efficiency varies with ambient conditions. Combustion turbine power production is a function of mass flow of air and exhaust gases through the turbine. As such, the lower the air density, the lower the power production and efficiency. Combustion turbine efficiency decreases as the ambient temperature increases, decreases as relative humidity decreases, and decreases as ambient pressure decreases.
- Power Production Basis: Combined-cycle combustion turbine plant efficiencies can be determined based on the overall production of power, gross efficiency, or on the power provided to the grid, net efficiency.

A search for efficiency information for permitted combined-cycle combustion turbine plants similar to the Bowie Power Station turbines was conducted and the results are summarized in Table 4-7. Efficiency data in Table 4-7 is for permitted combined-cycle combustion turbine plants similar in size to the Bowie Power Station plant operating without duct firing. Size is a significant factor in combustion turbine efficiency with efficiency increasing with increasing turbine size. While duct firing is an economic method of obtaining small capacity additions, it has a negative impact on plant efficiency that varies with duct burner size.

As shown in Table 4-7, the Bowie Power Station combined-cycle combustion turbine plant efficiency compares favorably with the efficiencies of similar projects. Installation of an efficient combined-cycle combustion turbines and an emission limit of 1,752,769 tons per year CO_2e emissions for the turbines and duct burners combined is proposed as BACT.

The EPA guidance document indicates a preference for output-based emission limits. An output-based emission limit is not proposed for the turbines and duct burners due to difficulty in determining an appropriate limit that accounts for the variation in heat input and electricity output for differing ambient conditions and operating modes. This problem was discussed at length during the development of the New Source Performance Standards for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK).

EPA initially proposed output-based limits on a pound per megawatt-hour (lb/MWh) basis for turbine NO_x limits in 40 CFR 60, Subpart KKKK. The agency received numerous comments explaining why achievable output-based limits were difficult to set for combustion turbines. Several commenters pointed out that combustion turbines are most efficient at full load and ISO conditions, the point at which components of the turbine are best matched for efficiency. "Any reduction in load or change in atmospheric conditions causes a reduction in efficiency" (American Petroleum Institute 2005). As a result, output-based emission rates would increase at partial load conditions, even though emissions on a mass basis would not. EPA acknowledged this problem in the Preamble to the proposed rule: "… at part-loads there may be a concern about higher output-based NO_x levels emitted due to lower thermal efficiencies." (70 Federal Register 8319, February 18, 2005) The increase in output-based emissions at partial loads with no increase in mass emissions would be equally true for GHGs.

Commenters also pointed out an output-based limit would become untenable at extremely low or zero load conditions, which would occur at Bowie, for example, for a portion of the startup sequence when the turbines may be emitting but no or very little electricity is being generated. GE drew the logical conclusion that "a standard that is predicated on the full load capability of a given gas turbine must either make an allowance for part load operation, or apply a limit that is so high as to be of no consequence at full load (and in essence hollow as a regulatory imposition)" (GE 2005).

With respect to 40 CFR 60, Subpart KKKK, EPA acknowledged the commenters conclusions regarding the difficulty in setting achievable output-based limits for combustion turbines and ultimately gave owners/operators of affected facilities the choice of meeting either concentration-based or output-based limits. For the reasons stated above, an output-based limit for GHG emissions has not been proposed for the Bowie Power Station.

A BACT limit must not be higher than an applicable NSPS emission limit. On 20 September 2013 EPA proposed changes to 40 CFR 60, Subpart KKKK to incorporate CO_2 emissions limits. These changes have not yet been finalized and there is not yet an applicable GHG NSPS emission limit to which the proposed BACT limit must be compared.

Table 4-7. Combined-cycle Combustion Turbine Efficiency and Permit Limits

Efficiency Basis	Project/Reference	Efficiency (Btu/kWh)[a]	Permit Limit
HHV ISO Conditions Net	Thomas C. Ferguson Power Plant (EPA 2011d and EPA 2011e)	6,575	7,720 Btu/kWh (365-day rolling average) 0.459 tons CO_2/MWh (365-day rolling average) 908,957.6 tons CO_2e/year (each turbine)
	Oregon Clean Energy Center[b] (OCEC 2012 and OEPA 2013)	6,687	11,671 tons per rolling 12-month period
	Virginia Electric and Power Company – Brunswick Plant (VDEQ 2013a and VDEQ 2013b)	6,695	7,500 Btu/kWh 920 lb CO_2e/MWh (annual average) 1,763,902 tons CO_2e/year (three turbines with duct burners)
	Woodbridge Energy Center (NJDEP 2012a and NJDEP 2012b)	6,740	7,605 Btu/kWh
	CPV Valley Energy Center (NYDEC 2013)		7,605 Btu/kWh
	Bowie Power Station	**6,751**	1,752,769 tons per year CO_2e (two turbines and duct burners combined)
	St. Joseph Energy Center, LLC (IDEM 2012)	6,779	7,646 Btu/kWh 4,736,936 tons CO_2e per 12 month period (four turbines)
	Russell City Energy Center (BAAQMD 2010a and BAAQMD 2010b)	6,852	7,730 Btu/kWh 1,928,182 metric tons CO_2e/year (two turbines)
	Channel Energy Center, LLC (Channel Energy 2011, EPA 2012a, EPA 2012b)	6,852	7,730 Btu/kWh
	Deer Park Energy Center[b] (Deer Park 2011 and EPA 2012c)	6,970	7,730 Btu/kWh[c]
	Effingham County Power Plant[c] (GDNR 2012, Golder 2011)	6,852[e]	863,953 tons CO_2e/year (each turbine)
	Palmdale Hybrid Power Project[b] (Palmdale 2011 and EPA 2011f)	6,970	774 lb CO_2/MWh (net)[d] 117 lb CO_2/MMBtu input (30-day rolling average)
LHV ISO Conditions Net	Cricket Valley Energy Project (Cricket Valley 2011 and NYDEC 2012)	6,742	7,605 Btu/kWh[d] 3,576,943 tons CO_2e/rolling 12-month total (three turbines)
	Bowie Power Station	**6,087**	1,752,769 tons per year CO_2e (two turbines and duct burners combined)
	Hess Newark Energy Center[b] (Hess Newark 2011, NJDEP 2012c.)	6,005	2,000,268 tons/year CO_2e (two turbines and two duct burners)
HHV ISO Conditions Gross	Green Energy Partners/Stonewall LLC (VDEQ 2013c)	6,550	7,340 Btu/kWh without duct firing 7,780 Btu/kWh with duct firing 2,418,273 tons CO_2e/year (two turbines)
	Bowie Power Station	**6,576**	1,752,769 tons per year CO_2e (two turbines and duct burners combined)
	Entergy Louisiana LLC – Ninemile Point Plant (LDEQ 2011a and LDEQ 2011b)	6,766[e]	7,630 Btu/kWh

[a] Without duct firing, unless otherwise indicated.
[b] Value not designated as net or gross. Net assumed.
[c] Values in greenhouse gas best available control technology analysis were not specified as higher or lower heating value and were not specified as net or gross. Values were assumed to be HHV and net.
[d] Limit not specified as LHV or HHV. LHV assumed as efficiency value is LHV.
[e] With duct firing.

Notes:

Btu/kWh	=	British thermal units per kilowatt hour	LHV	=	Lower heating value
CO_2	=	Carbon dioxide	MMBtu	=	Million British thermal units
CO_2e	=	Carbon dioxide equivalent	MWh	=	Megawatt hours
HHV	=	Higher heating value			
lb CO_2e/MWh	=	Pounds carbon dioxide equivalent per megawatt hour			

4.4.6 Auxiliary Boiler NO_x Analysis

This project includes one 50 MMBtu/hr boiler that will operate a maximum of 450 hours per year (hr/yr). The boiler will be equipped with low NO_x burners and flue gas recirculation that are integral to the boiler design and function. The BACT analysis for NO_x emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies Auxiliary Boiler NO_x Analysis

The following control methods have been identified for reducing NO_x emissions from the natural-gas fired auxiliary boiler:

- SCR;
- SNCR;
- Ultra-low NO_x burners;
- Flue gas recirculation (FGR); and
- Low NO_x burners.

SNCR is a post-combustion control method in which ammonia or urea is injected into the exhaust stream, reducing NO_x to nitrogen and water. SCR is similar to SNCR in that it is a post-combustion NO_x control method in which ammonia is injected into the exhaust stream. However, SCR systems use a catalytic reactor to overcome the temperature and residence issues that can occur with SNCR.

Ultra-low NO_x burners and low NO_x burners are designed to reduce thermal NO_x formation. This is accomplished using designs such as staged air burners, staged fuel burners, pre-mix burners, internal recirculation, and radiant burners. These burners may be used by themselves or in conjunction with FGR. FGR recirculates a portion of the combustion exhaust stream back to the combustion zone. This reduces thermal NO_x by reducing peak temperature and available oxygen.

Step 2: Eliminate Technically Infeasible Options Auxiliary Boiler NO_x Analysis

All of the identified control options are technically feasible for the Bowie auxiliary boiler.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Auxiliary Boiler NO_x Analysis

SCR systems can achieve NO_x control efficiencies of 90% or greater (ICAC 2010). SNCR reduction levels range from 30% to 75% (ICAC 2010). Ultra-low NO_x burners are guaranteed with NO_x exhaust gas concentrations of 9 ppmv. Low NO_x burners achieve NO_x gas concentrations of 30 ppmv. FGR is often incorporated into ultra-low NO_x and low NO_x burners, including the Bowie auxiliary boiler burners, and will not be considered further as a separate control option.

The control effectiveness ranking for auxiliary boiler NO_x controls is:

1) SCR;
2) SNCR;
3) Ultra-low NO_x burners; and
4) Low NO_x burners.

Step 4: Evaluate Most Effective Controls and Document Results
Auxiliary Boiler NO_x Analysis

Low NO_x burners are proposed as the basis for BACT for the auxiliary boiler. The higher ranked control options have extreme economic impacts and are not cost effective in this case. The auxiliary boiler is being permitted to operate only 450 hr/yr, which results in annual NO_x emissions of only 0.41 tpy.

Cost effectiveness values have been calculated for SNCR, SCR, and ultra-low NO_x burners and are provided in Appendix D. A 2008 document by the Northeast States for Coordinated Air Use Management (NESCAUM 2008) estimated the capital cost of industrial boiler SNCR at $4,297 per MMBtu/hr (NESCAUM 2008). Using only the capital costs, a cost effectiveness value of $76,713 per ton was calculated for SNCR. This is much higher than is normally considered reasonable for BACT.

The same document contains an estimated capital cost for SCR of $8,359 per MMBtu/hr (NESCAUM 2008). Using only the capital costs, a cost effectiveness value of $124,360 per ton was calculated for SCR. This is much higher than is normally considered reasonable for BACT.

In 2008, the SJVUAPCD amended a rule limiting emissions from boilers, steam generators, and process heaters. As part of rule development, a cost analysis was conducted for control options including ultra-low NO_x burners (SJVUAPCD 2008). Information from the SJVUAPCD rule development was used to calculate a cost effectiveness value for ultra-low NO_x burners for the Bowie auxiliary boiler. The resulting cost effectiveness value is $116,934 per ton. This is clearly beyond what is normally considered reasonable for BACT.

Step 5: Select BACT
Auxiliary Boiler NO_x Analysis

SCR, SNCR and ultra-low NO_x burners are eliminated as BACT because of high cost impacts. Purchase of an auxiliary boiler with low NO_x burners designed to achieve a 30 ppmv NO_x concentration in the exhaust gas and operation limited to 450 hours per year are proposed as the basis for BACT for the auxiliary boiler. The emission rate corresponding to 30 ppmv NO_x is 0.036 lb/MMBtu.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." However, Subpart Dc does not include a NO_x emission limit for natural gas-fired steam generators.

4.4.7 Auxiliary Boiler CO Analysis

The BACT analysis for CO emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies
Auxiliary Boiler CO Analysis

The following control methods have been identified for reducing CO emissions from the auxiliary boiler:

- Oxidation catalyst; and
- Good combustion practices.

Step 2: Eliminate Technically Infeasible Options
Auxiliary Boiler CO Analysis

The operating temperature window for oxidation catalysts is from 500°F to 1100°F (NJDEP 2004). The auxiliary boiler exhaust temperature of 300°F is outside this range and use of an oxidation catalyst is infeasible for the auxiliary boiler.

Step 5: Select BACT
Auxiliary Boiler CO Analysis

Use of good combustion practices is the only remaining control option. As a result, Steps 3 and 4 are unnecessary and purchasing a boiler designed to meet an emission concentration of 50 ppmv and operation limited to 450 hours per year are chosen as the basis for BACT for the auxiliary boiler. The boiler manufacturer's guaranteed emission rate corresponding to an exhaust concentration of 50 ppmv is 0.037 lb/MMBtu.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." However, Subpart Dc does not include a CO emission limit for natural gas-fired steam generators.

4.4.8 Auxiliary Boiler $PM/PM_{10}/PM_{2.5}$ Analysis

The BACT analysis for $PM/PM_{10}/PM_{2.5}$ emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies
Auxiliary Boiler $PM/PM_{10}/PM_{2.5}$ Analysis

$PM/PM_{10}/PM_{2.5}$ emissions from combustion of natural gas are low and the concentration in the exhaust flow is also low, making it very difficult to control emissions from natural gas-fired boilers. For these reasons, add-on control devices such as scrubbers, ESPs, and fabric filters have not been demonstrated in practice on gas-fired boilers (SJVUAPCD 2008) and are not considered available for the auxiliary boiler.

The use of low sulfur fuel can minimize particulate sulfate emissions and is an available control option for the auxiliary boiler.

Step 5: Select BACT
Auxiliary Boiler $PM/PM_{10}/PM_{2.5}$ Analysis

Use of low sulfur fuel is the only available control option for the Bowie natural gas-fired auxiliary boiler. Therefore, Steps 2 through 4 are unnecessary and the use of low sulfur fuel is chosen as the basis for $PM/PM_{10}/PM_{2.5}$ BACT, with a proposed limit of 0.007 lb/MMBtu based on the manufacturer's guarantee.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." However, Subpart Dc does not include particulate matter emission limits for natural gas-fired steam generators.

4.4.9 Auxiliary Boiler GHG BACT Analysis

The BACT analysis for CO emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies Auxiliary Boiler GHG Analysis

There are no add-on control options for GHG emissions from non-electrical generation boilers. There are options that increase the efficiency of boilers thereby reducing emissions by reducing fuel use. Equipment and actions that increase boiler efficiency are:

- Electronic ignition;
- Optimization of excess air;
- Stack gas heat recovery — air preheaters and economizers;
- Blowdown waste heat recovery;
- Blowdown optimization; and
- Proper boiler maintenance.

Electronic ignition eliminates the need for pilot light fuel combustion.

Excess air optimization balances the heat losses associated with heating combustion air in excess of stoichiometric conditions while providing sufficient combustion air to avoid excess CO emissions.

Air preheaters recover stack gas heat and use it to heat the incoming combustion air. Economizers recover stack gas heat and use it to pre-heat boiler feed water.

Blowdown waste heat recovery systems reduce losses associated with the energy contained in the hot water and solid particles discharged during blowdown. The recovered heat is used to pre-heat boiler feed water.

Blowdown optimization balances the need to control solids with the waste heat lost in the blowdown. Excessive blowdown reduces boiler efficiency while insufficient blowdown may lead to deposits or carryover.

Proper boiler maintenance keeps boiler efficiency high. Periodic boiler tune-ups ensure that proper excess air control is maintained. Cleaning heat transfer surfaces avoids reductions in heat transfer and increased fuel use caused by scaling. Inspections to identify repair problems with steam distribution equipment, steam traps, and piping insulation assist in avoiding energy losses and increased fuel use.

Step 2: Eliminate Technically Infeasible Options Auxiliary Boiler GHG Analysis

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. All options listed in Step 1 are technically feasible for the Bower Power Station auxiliary boiler.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Auxiliary Boiler GHG Analysis

An EPA Climate Leaders document *Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology for Project Type: Industrial Boiler Efficiency (Industrial Process Applications)* contains efficiency improvement ranges for the efficiency options under consideration (EPA 2008b). These options are presented in Table 4-8.

Table 4-8. Auxiliary Boiler Efficiency Options Effectiveness

Efficiency Option	Efficiency Range (%)
Non-Condensing Economizer	1 – 7[a]
Condensing Economizer	1 – 2[a]
Air Preheaters	1 – 2[a]
Blowdown Waste Heat Recovery	1 – 2[a]
Optimize Excess Air	1[a]
Blowdown Optimization	Avoids Reduction in Efficiency
Proper Maintenance	Avoids Reduction in Efficiency

[a] From *Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology for Project type: Industrial Boiler Efficiency (Industrial Process Applications)*, Climate Protection Partnerships Division/Climate Change Division, EPA, August 2008.

Notes:
% = Percent

The various efficiency improvement options can be implemented individually or in combination. This includes implementation of all of the options together with the exception of the economizer. A non-condensing and condensing economizer could not both be used at the same time.

Step 4: Evaluate Most Effective Controls and Document Results Auxiliary Boiler GHG Analysis

In this step the environmental, energy, and economic impacts of the options are considered. There are no negative energy impacts associated with any of the options. All of the efficiency options save energy by increasing efficiency and reducing fuel use.

The only possible environmental impacts are increased NO_x emissions with air preheaters, increased CO emissions with excess air control, and increased wastewater generation with blowdown control. For excess air control and boiler blowdown, optimization to minimize the environmental impacts, while achieving the desired boiler efficiency, is an integral part of the option.

Air preheaters can impact NO_x emissions by increasing the peak flame temperatures in the boiler. In conjunction with low NO_x burners, boilers can be equipped with flue gas recirculation (FGR) to control NO_x emissions. FGR is used to lower peak flame temperature. Boilers are designed for optimum flame temperature for proper boiler operation and to minimize NO_x emissions. An air preheater in combination with low NO_x burners and FGR would adversely impact boiler flame temperature and increase NO_x emissions.

For the options other than blowdown optimization and proper maintenance, the cost of additional equipment presents an economic impact that is offset by the decreased fuel consumption that results from increased efficiency.

Step 5: Select BACT Auxiliary Boiler GHG Analysis

The auxiliary boiler will be equipped with the following energy efficiency measures:

- Electronic ignition;
- Optimization of excess air using low NO_x burners; and
- A non-condensing economizer to recover stack gas heat and preheat feed water;

Use of these efficiency measures result in a gross boiler efficiency when new of 83.7% (HHV). The blowdown will be optimized and the boiler will be properly maintained to maintain the boiler's efficiency.

Blowdown waste heat recovery will not be used as the economizer will preheat the feed water using stack waste heat instead. An air preheater will not be used as the boiler will be equipped with low NO_x burners and FGR and be designed to control the combustion temperature to optimize efficiency while minimizing NO_x emissions. Inclusion of an air preheater would impact this balance.

The previously mentioned Climate Leaders document on industrial boiler efficiency developed a performance standard for GHG offset projects designed to increase boiler efficiency. EPA explained the choice of a technology based standard, "The technology-based threshold was selected because the efficiencies of industrial boiler applications fall within a range that is dictated by operational and emission requirements making no single efficiency/emissions performance value applicable for a particular set of industrial boilers" (EPA 2008a). Given this determination, a comparison of the efficiency of the auxiliary boiler with other boilers was not conducted.

Based on the use of the identified boiler efficiency measures that provide the auxiliary boiler with a gross efficiency of 83.7% (HHV), an emission limit of 1,316.5 tons CO_2e per year reflecting use of these energy efficiency measures and maximum operation of 450 hours per year is proposed as BACT for GHG emissions. An output based emission limit is not proposed given the infrequent operation of the auxiliary boiler.

4.4.10 Emergency Fire Pump NO_x Analysis

The project includes a diesel-fired, 260 horsepower (hp), emergency fire pump that will operate no more than 100 hr/yr in non-emergency service. The BACT analysis for NO_x emissions from the emergency fire pump is presented in this section.

Step 1: Identify All Control Technologies Emergency Fire Pump NO_x Analysis

The emergency fire pump is a diesel-fired, internal combustion engine. The following control options have been identified for the diesel-fired emergency fire pump:

- SCR;
- SNCR (NO_xTech);
- Water injection; and
- Combustion controls.

NO_x adsorbers, also called lean NO_x traps, and Lean NO_x catalyst controls are post-combustion control devices that have been developed for controlling NO_x from on-road diesel engines. There has been no use of NO_x adsorbers on stationary diesel engines nor have there been any studies of their use on stationary engines (EPA 2010b). Lean NO_x catalyst controls have also not been used on stationary diesel engines (EPA 2010b). As such, NO_x adsorbers and lean NO_x catalyst controls are not considered available for use on the Bowie fire pump engine.

Step 2: Eliminate Technically Infeasible Options Emergency Fire Pump NO_x Analysis

SCR, SNCR, water injection, and combustion controls are considered feasible for the Bowie fire pump engine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Emergency Fire Pump NO_x Analysis

The next step is to rank the control technologies by effectiveness. The post-combustion control options, SCR and SNCR, can achieve greater than 90% NO_x control efficiencies (Alpha-Gamma Technologies, Inc. 2005). Combustion control can reduce emissions by as much as 80% (Alpha-Gamma Technologies, Inc. 2005) and water injection reduces emissions by 25%-35%. Table 4-9 shows the control effectiveness ranking.

Table 4-9. Fire Pump Engine NO_x Control Ranking

Control Option	Control Efficiency
Post-combustion control options	>90%
Combustion controls	80%
Water injection	25%-35%

Notes:
% = Percent
> = Greater than

Step 4: Evaluate Most Effective Controls and Document Results Emergency Fire Pump NO_x Analysis

Given the limited hours of operation and corresponding small annual NO_x emissions (0.06 tpy), the cost impacts associated with post-combustion NO_x controls are prohibitive. Cost information obtained has been obtained from available references and used to calculate cost effectiveness values for the fire pump engine (see Appendix D). An emission control efficiency of 95% was assumed for the post-combustion control options. The cost effectiveness information for the post combustion controls is summarized in Table 4-10.

Table 4-10. Fire Pump Engine NO_x Post Combustion Control Costs

Control Option	Annualized Cost ($/ton)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction	$9,520	0.060	$159,064
Selective Non-Catalytic Reduction (NO_xTech)	$1,427	0.060	$23,848

Notes:
tpy = Tons per year
$/ton = Dollars per ton

As indicated by the values in Table 4-10, the application of post-combustion control to the fire pump engine would have a large economic impact.

Step 5: Select BACT Emergency Fire Pump NO_x Analysis

The final step in the top-down BACT analysis process is to select BACT. Limiting hours of operation to 100 hours per year and combustion control to achieve a NO_x emission rate of 2.2 grams per horsepower-hour (g/hp-hr) are proposed as BACT. Post-combustion controls are not chosen as BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. Emissions limits from 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines," will apply to the emergency fire pump. The fire pump engine chosen for the project will meet the combined NO_x and non-methane hydrocarbon emission limit of 3.0 g/hp-hr applicable to engines with a rated horsepower between 175 and 300 installed after 2009.

4.4.11 Emergency Fire Pump CO Analysis

The BACT analysis for CO emissions from the emergency fire pump is presented in this section.

Step 1: Identify All Control Technologies Emergency Fire Pump CO Analysis

Control options identified for CO emissions from diesel-fired internal combustion engines are:

- Oxidation catalysts;
- Catalyzed diesel particulate filters (CDPF);
- Flow through filters; and
- Combustion controls.

Lean NO_x catalyst controls are post-combustion control devices that have been developed for controlling emission from on-road diesel engines. Lean NO_x catalysts have not been used on stationary diesel engines (EPA 2010b) and are not considered available for this analysis.

Step 2: Eliminate Technically Infeasible Options Emergency Fire Pump CO Analysis

The identified control options are technically feasible for the emergency fire pump.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Emergency Fire Pump CO Analysis

The post-combustion control methods, oxidation catalysts, CDPF, and flow through filters, identified as feasible control options for the emergency fire pump, are the top ranked controls.

Oxidation catalysts are less effective when used on emergency equipment than when used on equipment that is operated in a more continuous manner (ICCR 1998b). Oxidation catalysts provide control once the effective temperature is reached. The emergency fire pump will only be operated for brief periods of time. This means that during a portion of the operation, the oxidation catalysts may not have reached temperature and will not be providing control. It is for this reason that oxidation catalysts are seldom used on emergency equipment. For purposes of this analysis, it has been assumed that an oxidation catalyst will provide control throughout emergency fire pump operation and will provide a 90% control efficiency.

CDPF can provide CO, PM, and VOC control. As with oxidation catalysts, exhaust temperatures are important to the operation of CDPF. The exhaust temperature must be sufficient to facilitate regeneration. This may be a problem with an emergency fire pump that operates infrequently and for short periods of time. However, as with oxidation catalysts, CDPF has been assumed to be a feasible option providing CO emission control during fire pump operations. CDPF can provide a CO emission reduction of 90% (EPA 2010b).

Flow through filters can control CO, PM, and VOCs. One manufacturer has demonstrated CO control of 90% (EPA 2010b).

Step 4: Evaluate Most Effective Controls and Document Results
Emergency Fire Pump CO Analysis

The top ranked technologies are the use of oxidation catalysts, CDPF, or a flow through filter. Because of the low emissions associated with the emergency fire pump, cost impacts associated with the use of these controls are very high.

EPA's *Alternative Control Techniques Document: Stationary Diesel Engines* contains cost information for diesel oxidation catalysts, CDPF, and flow through filters (EPA 2010b). This information has been used to calculate a cost effectiveness value for their use to control CO emissions from the emergency fire pump (see Appendix D). The calculated cost effectiveness values are:

- Oxidation catalyst: $48,168/ton;
- CDPF: $120,054/ton; and
- Flow through filters: $41,285/ton.

These values are clearly excessive.

Step 5: Select BACT
Emergency Fire Pump CO Analysis

Limiting hours of operation to 100 hours per year and combustion control, with a corresponding emission rate of 1.42 g/hp-hr, is selected as CO BACT for the emergency fire pump. Oxidation catalysts, CDPF, and flow through filters have not been selected as CO BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. The emergency fire pump will be an affected facility under 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." The fire pump engine chosen for the project with meet the CO limit of 2.6 g/hp-hr applicable to engines with a rated hp between 175 and 300.

4.4.12 Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

The BACT analysis for $PM/PM_{10}/PM_{2.5}$ emissions from the emergency fire pump is presented in this section.

Step 1: Identify All Control Technologies
Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

Methods identified for controlling $PM/PM_{10}/PM_{2.5}$ emissions from diesel-fired internal combustion engines are:

- Diesel particulate filters;
- CDPF;
- Flow through filters; and
- Low sulfur fuel.

Step 2: Eliminate Technically Infeasible Options
Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

All of the identified control options are feasible for the Bowie fire pump.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

The control ranking is presented in Table 4-11.

Table 4-11. Fire Pump Engine Particulate Matter Control Ranking

Control Option	Control Efficiency[a]
Diesel particulate filters	90%
Catalyzed diesel particulate filters	90%
Flow through filters	75%
Low sulfur fuel	Not Applicable

[a] Control efficiencies are from the US Environmental Protection Agency document, *Alternative Control Techniques Document: Stationary Diesel Engines*, 2010.
Notes:
% = Percent

Step 4: Evaluate Most Effective Controls and Document Results Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

The $PM/PM_{10}/PM_{2.5}$ emissions from the fire pump engine are very small due to the limited hours of operation. Installation and use of add-on control equipment for such small emissions is extremely cost prohibitive. Cost information from EPA's *Alternative Control Techniques Document: Stationary Diesel Engines* has been used to calculate cost effectiveness values for the add-on control options (see Appendix D). The resulting values are:

- Diesel particulate filters: $354,500/ton;
- CDPF: $1,447,712/ton; and
- Flow through filters: $597,412/ton.

These values are much higher than what is typically considered reasonable for BACT.

Step 5: Select BACT Emergency Fire Pump $PM/PM_{10}/PM_{2.5}$ Analysis

Limiting hours of operation to 100 hours per year and use of low sulfur fuel, with a corresponding emission rate of 0.12 g/hp-hr, is chosen as BACT for $PM/PM_{10}/PM_{2.5}$ for the emergency equipment. Diesel particulate filters, catalyzed diesel particulate filters, and flow through filters are rejected as BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. Emissions limits from 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines," will apply to the emergency fire pump. The fire pump engine chosen for the project will meet the particulate matter 0.15 g/hp-hr limit applicable after 2009 to engines with maximum power between 175 and 300 hp. In addition, Subpart IIII requires the use of ultra-low sulfur fuel. The fuel used in the emergency fire pump engine will meet the Subpart IIII requirements.

4.4.13 Emergency Fire Pump GHG Analysis

The BACT analysis for GHG emissions from the emergency fire pump is presented in this section.

Step 1: Identify All Control Technologies
Emergency Fire Pump GHG Analysis

There are no add-on options for control of GHG emissions from non-electric generation reciprocating engines. The only option identified that increases engine efficiency, reducing the fuel used and the emissions generated, for four-stroke, diesel-fired engines is the use of turbocharging and intercooling.

A turbocharger is an intake air compressor that forces more air and fuel into the cylinders increasing engine output. The discharge air from the turbocharger, the intake air for the engine, is heated by the compression. This reduces the air density and limits the mass of the intake air to the engine. To compensate for this increase in air temperature, a heat exchanger is used to cool the air between the turbocharger and the engine. This heat exchanger is referred to as an intercooler or aftercooler.

Step 2: Eliminate Technically Infeasible Options
Emergency Fire Pump GHG Analysis

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. Turbocharging and intercooling are feasible for the Bowie Power Station emergency fire pump engine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Emergency Fire Pump GHG Analysis

In this step the control options are ranked. The only two options identified are the use of turbocharging and intercooling to increase engine efficiency and use of an engine without turbocharging and intercooling. Obviously, use of a more efficient engine equipped with turbocharging and intercooling is the higher ranked option.

Step 4: Evaluate Most Effective Controls and Document Results
Emergency Fire Pump GHG Analysis

In this step the environmental, energy, and economic impacts of the options are considered.

The highest ranked option is the use of turbocharging and intercooling to increase engine efficiency. The use of turbocharging and intercooling does not have any associated environmental impacts. Turbocharging and intercooling increase engine efficiency and therefore have a positive energy impact. There are no significant economic impacts with the use of turbocharging and intercooling.

Step 5: Select BACT
Emergency Fire Pump GHG Analysis

The Bowie emergency fire pump engine will be equipped with turbocharging and intercooling, the highest ranked option. The efficiency of the engine is reflected in its fuel use rate. The engine will have a fuel input rate of 13.4 gallons per hour at full load.

The engine will be operated a maximum of 100 hours per year for reliability and testing purposes. Based on that usage rate and the 13.4 gallon per hour fuel input rate, an annual CO_2e emissions limit of 15.0 tons per year is proposed as BACT for the emergency fire pump engine.

4.4.14 Cooling Tower $PM/PM_{10}/PM_{2.5}$ Analysis

The BACT analysis for $PM/PM_{10}/PM_{2.5}$emissions from the cooling tower is presented below.

Step 1: Identify All Control Technologies Cooling Tower $PM/PM_{10}/PM_{2.5}$ Analysis

The following control methods have been identified for reducing $PM/PM_{10}/PM_{2.5}$ emissions from cooling towers:

- Wet cooling with drift eliminators;
- Dry cooling; and
- Hybrid cooling.

Wet cooling condenses steam in water-cooled condensers. Cooling is achieved by the evaporation of a fraction of the circulating water flow. Some of the water becomes entrained in the air passing through the tower. The entrained water droplets are referred to as drift. Particulate matter emissions come from the solids dissolved in the water droplets. Drift eliminators are used to reduce drift by causing the water droplets to change direction while passing through the eliminators. Drift eliminator performance is described in terms of a percentage of the circulating water.

Dry cooling uses air cooled condensers. Steam is condensed inside tubes using cooled air blown across the tubes. The only direct emissions that can occur from dry cooling are entrainment of dust by the fans.

Hybrid cooling includes components of both wet and dry cooling. These systems use less water than wet cooling with greater plant efficiency than dry cooling.

Step 2: Eliminate Technically Infeasible Options Cooling Tower $PM/PM_{10}/PM_{2.5}$ Analysis

The three identified control options are technically feasible for the project.

Step 3: Rank Remaining Control Technologies by Control Effectiveness Cooling Tower $PM/PM_{10}/PM_{2.5}$ Analysis

Wet and hybrid cooling generate direct particulate matter emissions. Although dry cooling does not generate drift emissions, the California Energy Commission has indicated that particulate emissions do occur with dry cooling (CEC 2001). The dry cooling system fans can suspend particles in the area of the cooling structures. Given that estimating the extent of the emissions generated in this manner would be difficult, and that much of the area around the cooling structures would be paved, for purposes of this analysis, these emissions have been ignored.

To prepare the control technology ranking when one of the options considered does not directly generate emissions is difficult. EPA indicates that the most effective method for comparing inherently lower-polluting processes is to express emissions performance “as an average steady state emissions level per unit of product produced” (EPA 1990). In this case, the product produced is electricity, which is measured in MWh.

Emissions associated with the turbine system using wet cooling and drift eliminators are presented in Section 2.0 and Appendix B of this permit application. These values have been used to calculate lb/MWh emission rates for PM, PM_{10} and $PM_{2.5}$. Emissions from the turbines and duct burners are assumed to remain the same for the turbine system with hybrid and dry cooling. Emissions in lb/MWh for a turbine system using hybrid or dry cooling have been estimated. For dry cooling, the

estimate only includes emissions from the turbines and duct burners. For hybrid cooling, the estimate includes emissions from the turbines, duct burners, and wet components of the system. A hybrid system consisting of a five cell cooling tower and parallel air cooled condensers has been chosen as an appropriate design for the Bowie Station for purposes of this analysis.

The emission rates in lb/MWh calculated for wet cooling, hybrid cooling, and dry cooling are shown in Table 4-12 (calculations are provided in Appendix D). The ambient temperature affects the amount of electricity that can be produced. As a result, a range of short-term lb/MWh emission rates has been calculated.

Table 4-12. Cooling Options $PM/PM_{10}/PM_{2.5}$ Emission Ranking

Cooling Option	System Emissions (lb/MWh)			System Emissions (tpy)			Reduction from Wet Cooling (tpy)		
	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Dry cooling	0.014-0.017	0.014-0.017	0.014-0.017	62.5	62.5	62.5	5.7	3.8	1.8
Hybrid cooling	0.015-0.018	0.015-0.018	0.014-0.017	65.3	64.4	63.4	2.9	2.0	0.9
Wet cooling	0.016–0.018	0.016-0.018	0.015-0.017	68.2	66.4	64.4	--		

Notes:

lb/MWh = Pounds per megawatt-hour
PM = Particulate matter
PM_{10} = Particulate matter less than 10 micrometers
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers
tpy = Tons per year

As indicated in Table 4-12, the lowest $PM/PM_{10}/PM_{2.5}$ emissions are for dry cooling and the highest are for wet cooling.

Step 4: Evaluate Most Effective Controls and Document Results Cooling Tower $PM/PM_{10}/PM_{2.5}$ Analysis

The energy, environmental, and economic impacts associated with the cooling options are evaluated below.

Energy Impacts

There are two energy-related impacts associated with cooling systems:

- Parasitic load; and
- Plant efficiency.

The first of these impacts, parasitic load, deals with the energy used by the cooling system itself. The second, plant efficiency, deals with the effect that the cooling system has on plant power production.

Parasitic power is the power needed by the cooling system for fans and pumps. A dry cooling system requires a greater air flow than a wet or hybrid system. This air flow is provided by fans. The difference in fan power required for dry cooling is offset somewhat by the water pumping requirements of a wet cooling system. A hybrid system requires less fan power than a dry system and less water pump power than a wet system. A study analyzing wet, hybrid, and dry cooling for the Bowie Station was conducted. The parasitic power requirements of the three cooling options are shown in Table 4-13.

As shown in Table 4-13, the hybrid cooling system has the highest parasitic power requirement followed by wet cooling. Advances in air cooled condenser design over the last five years have lowered the parasitic demand of dry cooling and the dry cooling system has the lowest parasitic power demand.

Table 4-13. Cooling Options Parasitic Power Requirements

Ambient Temperature:	10°F	59°F	102°F
Cooling Method	Parasitic Power Requirement (kilowatts)		
Dry cooling	9,469	12,293	11,885
Hybrid cooling	11,447	13,356	13,033
Wet cooling	12,497	12,423	12,385

Notes:
°F = Degrees Fahrenheit

In addition to the parasitic power requirements, the cooling system used for a combined-cycle plant directly affects the efficiency of the steam turbine generator and the amount of power that can be produced. A plant configured with wet cooling is more efficient and can produce more power than a plant configured with hybrid or dry cooling.

The Arizona Corporation Commission, Utilities Division Staff in a document titled *Use and Associated Costs of Wet, Dry, and Hybrid Cooling Systems in New Power Plants*, dated April 14, 2010 addressed these difference concluding, "Power plants operating at high thermal efficiencies require less cooling water and cost less to operate. High thermal efficiencies are not as easily achieved with dry cooling systems because ambient dry bulb temperatures are always higher than ambient wet bulb temperatures" (Arizona Corporation Commission 2010).

Steam turbines extract power from steam as it passes from high pressure and high temperature to lower pressure and lower temperature. After the turbine, the steam goes to a condenser. The energy available to drive the steam turbine in a combined-cycle system is directly affected by the steam turbine exhaust pressure. The steam turbine exhaust pressure is a function of the condenser temperature, which in turn is dependent on the temperature of the cooling water or air used to absorb the heat from the steam. A lower temperature at the condenser results in a lower turbine exhaust pressure. Above a practical lower limit, the lower the exhaust pressure, the greater the energy that can be produced.

For wet cooling towers, the temperature at the cooling tower outlet is the same as the condenser cooling water inlet temperature. The cooling water outlet temperature is a function of the wet bulb temperature of the ambient air. The wet bulb temperature takes into account the cooling effect of water evaporation and is a function of the ambient air temperature and humidity. Because no evaporation of water is involved with dry cooling, the performance of the cooling system is a factor of the ambient air temperature only. The ambient air temperature is also referred to as the dry bulb temperature.

The wet bulb temperature is always equal to or less than the dry bulb temperature. This means that the energy that can be produced from a plant configured with dry cooling will always be less than or equal to the power that can be produced by a plant configured with wet cooling. A system configured with a hybrid cooling system will produce more power than a dry system and less than a wet system.

As the ambient temperature increases, the difference in wet bulb and dry bulb temperatures increases. Given the dry climate and high temperatures experienced in Arizona, performance penalties associated with the use of dry or hybrid cooling are even greater than what would be encountered in a cooler, more humid climate.

The efficiency penalty associated with dry cooling increases the fuel required to produce power and reduces the peak power output that can be generated. The performance differences between wet, hybrid, and dry cooling for the Bowie project are show in Table 4-14.

Table 4-14. Cooling Options Power Production and Fuel Penalties

Cooling Option	Net Plant Output at 102°F (kW)	Net Plant Output % Difference from Wet Cooling	Net Plant Heat Rate (HHV) at 102°F (Btu/kWh)	Net Plant Heat Rate % Difference from Wet cooling
Dry cooling	506,959	-4.7	7,622	4.9
Hybrid cooling	505,655	-4.9	7,641	5.2
Wet cooling	531,890	--	7,264	--

Notes:

%	=	Percent
Btu/kWh	=	British thermal units per kilowatt hour
°F	=	Degrees Fahrenheit
kW	=	Kilowatts
HHV	=	Higher heating value

This analysis yielded a peak summer power differential of 4.7% for dry cooling and 4.9% for hybrid cooling. The peak summer differential is especially significant because it occurs during the period of highest electricity demand.

Environmental Impacts

There are environmental impacts associated with wet, hybrid, and dry cooling systems. Wet cooling systems have greater water consumption, greater wastewater production, and can generate visible plumes. A dry cooling system has greater noise impacts, greater visual impacts because the structures are larger, and, in terms of lb/MWh, greater emissions of pollutants other than $PM/PM_{10}/PM_{2.5}$. A hybrid system shares the environmental impacts of both wet and dry cooling.

Wet, hybrid, and dry cooling configurations require water for combustion turbine inlet evaporative cooler blowdown, HRSG blowdown, and miscellaneous other streams. Most of the water consumption in a wet or hybrid cooling configuration is evaporated in the cooling towers. The cooling system analysis conducted for the Bowie project indicated that a dry cooling system would take approximately 3.6% of the water required for a wet cooling system and a hybrid system would take approximately 38.2% of the water required for a wet system.

Wastewater is generated regardless of the cooling configuration used. Because of the lower water use associated with dry and hybrid cooling, less wastewater would be generated and smaller evaporation ponds would be needed than for wet cooling.

Visual impacts can occur with wet cooling systems when atmospheric conditions are sufficient to make the steam plume from the towers visible. Visual impacts from dry cooling systems occur because the cooling structures are large and very tall. The structures associated with dry cooling are generally 100 to 145 feet high. The wet cooling tower to be used at the Bowie Station will be 46 feet tall. The dry cooling structures are also more noticeable because the top 30 feet of a dry cooling tower structure appears as a solid wall (SMUD 2002). In addition to the visual impacts created by this solid wall, dispersion of emissions from the facility would be hindered under certain meteorological conditions by the wake effect created by the larger structure.

With aspects of both wet and dry cooling, hybrid cooling would have visual impacts associated with the possibility of visible plumes from the wet components and the large structure associated with the dry components.

Noise from dry cooling is also greater than noise from wet cooling. Wet cooling is generated by falling water, fans, and motors. Noise abatement is an integral part of the cooling tower design. Noise from dry cooling is primarily from air movement and fan motors. Dry cooling requires the movement of a large volume of air and a large number of fans are used. There are many more fans associated with dry cooling than with wet cooling. Because of the large volume of air moved, the number of fans used, and the height at which the fans would be located, the noise level beyond the plant boundary would be greater for dry cooling than for wet cooling. The noise level for hybrid cooling would be between the levels for wet and dry cooling. The Bowie Power Station will be located in a quiet, rural area and the increased noise associated with dry or hybrid cooling would be very noticeable and disruptive.

Plants using dry or hybrid cooling generate more air pollutant emissions per MWh of electricity produced than wet cooling because of the energy penalty discussed earlier. Emission rates in lb/MWh for the Bowie Power Station project have been calculated for wet, hybrid, and dry cooling configurations for NO_x, CO, VOCs, SO_2 and GHGs. For NO_x, CO, and VOCs, turbine and duct burner emissions vary with ambient temperature for all cooling configurations. The electricity that can be generated also varies with ambient temperature. A range of lb/MWh emission rates has been calculated and is provided in Appendix D. The greatest difference in emission rates occurs when the ambient temperature is high. Emission rates for an ambient temperature of 102°F are shown in Table 4-15.

Table 4-15. Other Pollutant Impacts at an Ambient Temperature of 102°F

Cooling Method	NO_x Emissions (lb/MWh)	CO Emissions (lb/MWh)	VOC Emissions (lb/MWh)	SO_2 Emissions (lb/MWh)	CO_2e Emissions (lb/MWh)
Dry cooling	0.055	0.034	0.015	0.014	890.56
Hybrid cooling	0.055	0.034	0.015	0.014	892.85
Wet cooling	0.053	0.032	0.014	0.014	848.77

Notes:

CO	=	Carbon monoxide
CO_2e	=	Carbon dioxide equivalents
Lb/MWh	=	Pounds per megawatt hour
NO_x	=	Oxides of nitrogen
SO_2	=	Sulfur dioxide
VOC	=	Volatile organic compounds

As shown in Table 4-12, the emission rates in lb/MWh for hybrid and dry cooling for pollutants other than $PM/PM_{10}/PM_{2.5}$ are greater than for a wet cooling configuration at high ambient temperatures.

Economic Impacts

There are two areas of economic impacts associated with dry cooling and hybrid cooling:

- Increased construction and installation costs; and
- Decreased revenue.

The cooling option analysis conducted for the Bowie project included obtaining capital cost estimates for dry, hybrid, and wet cooling systems. Construction and installation costs have been estimated at $46.6 million for a dry system, $47.3 million for a hybrid system, and $28.7 million for a wet system.

Estimates of operating and maintenance costs for the three cooling options have been made. Wet cooling has the highest operating and maintenance costs at $1.5 million per year compared to $1 million per year for hybrid cooling and $350,000 per year for dry cooling. The difference in operating and maintenance costs is primarily attributable to the cost of water treatment chemicals and side-stream softening system consumables.

Cost effectiveness and incremental cost values for PM, PM_{10}, and $PM_{2.5}$ have been estimated for the Bowie Power Station for dry and hybrid cooling systems. These cost calculations are provided in Appendix D and summarized in Table 4-16.

As shown in Table 4-16, the cost effectiveness and incremental costs of dry and hybrid cooling are unreasonably high and orders of magnitude higher than what is normally considered BACT.

The large cost associated with construction of a dry or hybrid cooling system is not the only associated economic impact. Decreased revenues as a result of the plant power production efficiency penalty associated with dry and hybrid cooling discussed earlier would also impose an economic impact. This impact would be especially large during the peak summer months when electricity demand, electricity price, and the size of the efficiency penalty peak are highest.

Impact Summary

A summary of the energy, environmental, and economic impacts is presented in Table 4-17.

Step 5: Select BACT

Cooling Tower PM/PM_{10}/$PM_{2.5}$ Analysis

For the Bowie Power Station, a plant configuration using wet cooling and drift eliminators is chosen as the basis for BACT for cooling tower PM, PM_{10}, and $PM_{2.5}$. Neither dry cooling nor hybrid cooling is chosen as BACT because of the greater energy, environmental, and economic impacts compared to wet cooling. Because of the efficiency penalty, dry and hybrid systems require more fuel to be combusted to produce electricity and reduce the amount of power that can be produced by the plant. Hybrid cooling has the highest parasitic power requirement of the three options. Dry and hybrid cooling would be more disruptive in a rural area with greater noise and visual impacts. Dry cooling would also introduce greater building wake effects and impact emission dispersion under certain meteorological conditions. Dry and hybrid cooling also have greater lb/MWh emission rates for NO_x, CO, VOCs, and GHG. Finally, dry and hybrid cooling have extreme economic impacts with high revenue penalties and cost effectiveness values that are orders of magnitude higher than what is considered reasonable for BACT.

A limit associated with wet cooling with drift eliminators is required to complete the BACT analysis. The drift eliminators proposed for this project will limit cooling tower drift to 0.0005% of the circulating cooling water. To verify that this level of drift elimination represents BACT, information from the RBLC and other available permits was collected. The collected information can be found in Appendix D. It shows that there have been no cooling towers with a drift level less than that proposed for the Bowie project. A drift rate of 0.0005% yielding the following emission rates is therefore proposed as BACT for this project:

- PM: 1.3 lb/hr;
- PM_{10}: 0.9 lb/hr; and
- $PM_{2.5}$: 0.4 lb/hr.

Table 4-16. Cooling Option Costs

Cooling Option	Annual Cost ($/year)	PM		PM_{10}		$PM_{2.5}$	
		Cost Effectiveness ($/ton)	Incremental Cost[a] ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost[a] ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost[a] ($/ton)
Dry cooling	$4,753,312	$838,327	$90,459	$1,241,074	$133,917	$2,611,710	$281,814
Hybrid cooling	$5,465,479	$1,866,302	$418,325	$2,759,785	$618,596	$5,823,327	$1,305,278
Wet cooling	$4,240,411	NA	NA	NA	NA	NA	NA

[a] Incremental cost between cooling option and wet cooling.

Notes:

$/ton = Dollars per ton
PM = Particulate matter
PM_{10} = Particulate matter less than 10 micrometers
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers

Table 4-17. Cooling Options Summary of Impacts

Cooling Method	Energy Impacts	Environmental Impacts	Cost Impacts
Dry cooling	▸ Reduced electricity production resulting from reduced efficiency, -4.7% differential during peak summer conditions ▸ Higher net heat rate (Btu/kWh) to compensate for reduced efficiency, 4.9% differential during peak summer conditions	▸ Greatest noise ▸ Greatest structure visibility ▸ Additional air pollutant emissions, including GHG emissions, to produce same electrical output	▸ Greatest construction and installation cost ▸ Extremely high cost effectiveness: PM: $838,327 per ton PM_{10}: $1,241,074 per ton $PM_{2.5}$: $2,611,710 per ton ▸ High incremental cost compared to wet cooling: PM: $90,459 per ton PM_{10}: $133,917 per ton $PM_{2.5}$: $281,814 per ton ▸ Decreased revenue
Hybrid cooling	▸ Reduced electricity production resulting from reduced efficiency, -4.9% differential during peak summer conditions ▸ Highest net heat rate (Btu/kWh) to compensate for reduced efficiency, 5.2% differential during peak summer conditions ▸ Highest parasitic power requirement	▸ Less noise than dry cooling, but more noise than wet cooling ▸ Potential plume visibility and greater structure visibility than wet cooling ▸ Additional air pollutant emissions, including GHG emissions, to produce same electrical output ▸ Greater water use than dry cooling, but less than wet cooling ▸ Greater wastewater than dry cooling, but less than wet cooling	▸ Greater construction and installation cost than wet cooling, but lower than dry cooling ▸ Extremely high cost effectiveness: PM: $1,866,302 per ton PM_{10}: $2,759,785 per ton $PM_{2.5}$: $5,823,327 per ton ▸ Extremely high incremental cost compared to wet cooling: PM: $418,325 per ton PM_{10}: $618,596 per ton $PM_{2.5}$: $1,305,278 per ton ▸ Decreased revenue
Wet cooling	--	▸ Greatest water use ▸ Potential plume visibility ▸ Greatest volume of wastewater	▸ Highest operational and maintenance costs

Notes:

Btu/kWh	=	British thermal units per kilowatt hour
GHG	=	Greenhouse gas
PM	=	Particulate matter
PM_{10}	=	Particulate matter less than 10 micrometers
$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
$	=	Dollars (US)
%	=	Percent

4.4.16 Circuit Breakers GHG Analysis

There will be an electrical switchyard within the Bowie Power Station boundary. The switchyard will include five circuit breakers each containing 360 lbs of sulfur hexafluoride (SF_6), a potent GHG. SF_6 is a highly effective dielectric used for interrupting arcs and is the universally accepted medium for high-voltage circuit breakers (McDonald 2007). The circuit breakers located on the Bowie Power Station site will have the potential for fugitive emissions of SF_6 as a result of equipment leaks. The BACT analysis for GHG emissions from the circuit breakers is presented below.

Step 1: Identify All Control Technologies Circuit Breaker GHG Analysis

Three control options have been identified for the SF_6 emissions from the circuit breakers.

- Use of another type of circuit breaker:
  - Oil circuit breakers,
  - Air blast breakers, or
  - Vacuum breakers;
- Use of a different dielectric; and
- Use of leak detection monitoring.

Air-blast, oil, and vacuum circuit breakers are three available alternative circuit breaker types. SF_6 circuit breakers provide superior performance to these alternatives (National Institute of Standards and Technology [NIST] 1997). "SF_6 is about 100 times better than air for interrupting arcs" (McDonald 2007).

To reduce SF_6 emissions, other dielectric gases and mixtures of SF_6 with other gases are being investigated as replacements for SF_6 alone.

Leak detection monitoring is used to minimize emissions by identifying and repairing leaks as soon as possible.

Step 2: Eliminate Technically Infeasible Options Circuit Breaker GHG Analysis

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review.

Use of vacuum circuit breakers is not a technically feasible option. The Bowie Power Station 345 kV circuit breakers are high voltage circuit breakers. Vacuum circuit breakers are used for medium voltage levels. Prototype large voltage vacuum circuit breakers have been developed; however, as indicated in a paper presented at the 2009 International Conference on Renewable Energies and Power Quality, "it is necessary to introduce changes in the design and the materials used to ensure the proper working of VCB [vacuum circuit breaker] at higher voltage values" (Iturregi 2009). Vacuum circuit breakers are not available for high voltage applications and are therefore not available for the circuit breakers to be located on the Bowie Power Station site.

Oil and air-blast circuit breakers are also not an available option for high voltage applications as they are no longer being offered by manufacturers (Lester 2008). Oil and air-blast circuit breakers were commonly used for voltage applications from 15 kV to 345 kV until the mid-1970s (Garzon 2002), but have since been replaced by SF_6 circuit breakers.

SF_6 breakers replaced oil and air-blast breakers because of their superior performance, but also because of other issues with oil and air-blast breakers. The oil breaker disadvantages were flammability and high maintenance costs. The maintenance costs were a result of oil replacement requirements. Oil in circuit breakers is degraded by small quantities of water and by carbon deposits from the carbonization that occurs when the oil comes into contact with the electric arc.

Air-blast circuit breakers require the installation of expensive compression stations, are very large, and create a very high level of noise on operation. In a document discussing possible alternatives to use of SF_6 alone, NIST stated that SF_6 is used almost exclusively because "It offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads" (NIST 1997).

EPA's SF_6 Emission Reduction Partnership for Electric Power Systems, a voluntary public-private partnership focused on reducing SF_6 emissions, has not advocated for a return to oil or air-blast breakers for high voltage applications, but instead has focused on leak detection and repair, education of SF_6 handlers, and replacement of older SF_6 circuit breakers with new SF_6 breakers.

Use of an alternative dielectric is not a feasible option as there are no replacement gases that have been developed. Decades of investigation have found alternatives for medium voltage electric power equipment, but no viable alternative to SF_6 for high-voltage equipment (McDonald 2007). The 2010 annual report (the most recent available) for the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems states, "Because there is no clear alternative to SF6, Partners reduce their greenhouse gas emissions through implementing emission reduction strategies …" (EPA 2011g).

Use of leak detection monitoring is feasible for the circuit breakers to be located at the Bowie Power Station site.

Step 5: Select BACT
Circuit Breaker GHG Analysis

As leak detection monitoring is the only remaining control option for the SF_6 circuit breakers, Steps 4 and 5 are unnecessary and leak detection monitoring is selected as the basis for BACT. A work practice standard requiring leak detection monitoring that will alert when a circuit breaker loses 10% of its SF_6 is proposed as BACT for the circuit breakers.

4.4.16 BACT Summary

A summary of the results of the BACT analyses is presented in Table 4-18.

Table 4-18. BACT Summary

Emission Unit	Pollutant	Control Method	Limit
Turbines and Duct Burners — Normal Operation[a]	NO_x	Dry Low NO_x Combustion and Selective Catalytic Reduction	2 ppmv at 15% O_2, 1-hour average
	CO	Oxidation Catalyst	2 ppmv at 15% O_2, 1-hour average
	$PM/PM_{10}/PM_{2.5}$	Natural Gas	8.5 lb/hr average of three source test runs
	GHG	Efficient Electricity Production	CO_2e: 1,752,769.1 tpy (two turbines and two duct burners combined)
Turbines and Duct Burners — Startup, Shutdown, and Tuning[a]	NO_x	Work Practices	Hot Start: 50.7 lb/turbine/event Warm Start: 78.9 lb/turbine/event Cold Start: 78.9 lb/turbine/event Tuning: 78.9 lb/turbine/hour Shutdown: 16.4 lb/turbine/event
	CO	Work Practices	Hot Start: 131.1 lb/turbine/event Warm Start: 145.0 lb/turbine/event Cold Start: 145.0 lb/turbine/event Tuning: 145.0 lb/turbine/hour Shutdown: 51.5 lb/turbine/event
Auxiliary Boiler	NO_x	Low NO_x Burners	0.036 lb/MMBtu
	CO	Good Combustion Practices	0.037 lb/MMBtu
	$PM/PM_{10}/PM_{2.5}$	Low Sulfur Fuel	0.007 lb/MMBtu
	GHG	Limited Operation and Boiler Efficiency	CO_2e: 1,316.5 tpy
Emergency Fire Pump	NO_x	Limited Operation and Combustion Control	2.2 g/hp-hr
	CO	Limited Operation and Combustion Control	1.4 g/hp-hr
	$PM/PM_{10}/PM_{2.5}$	Limited Operation and Low Sulfur Fuel	0.12 g/hp-hr
	GHG		CO_2e: 15.0 tpy
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	Wet Cooling with Drift Eliminators	PM: 1.3 lb/hr PM_{10}: 0.9 lb/hr $PM_{2.5}$: 0.4 lb/hr
Circuit Breakers	GHG	Leak Detection Monitoring	Alarm at 10% Loss

[a] Limits show are for each turbine and duct burner pair.

Notes:

CO	=	Carbon monoxide	lb/MMBtu	=	Pounds per million British thermal units
g/hp-hr	=	Grams per horsepower hour	lb/turbine/event	=	Pounds per turbine per event
GHG	=	Greenhouse gases	PM	=	Particulate matter
lb	=	Pounds	PM_{10}	=	Particulate matter less than 10 micrometers
lb/hr	=	Pounds per hour	$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
NO_x	=	Oxides of nitrogen	tpy	=	Tons per year

5.0 AIR QUALITY IMPACT ANALYSIS SUMMARY

This section summarizes the air quality impact analyses conducted for the Bowie Power Station. A complete report of the analysis is included as Appendix E.

The project has the potential to emit more than 100 tons per year (tpy) of oxides of nitrogen (NO_x) and carbon monoxide (CO). In addition, the project has the potential to emit more than 15 tpy of particulate matter with an aerodynamic equivalent diameter less than or equal to 10 micrometers (PM_{10}), and 10 tpy of particulate matter with an aerodynamic equivalent diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) (NO_x is also considered a precursor to both PM_{10} and $PM_{2.5}$). An air quality impact analysis is required for these pollutants. The analysis included the following components:

- Dispersion modeling to determine whether ambient impacts due to the proposed project would exceed modeling significant impact levels (SILs);
- For 1-hour nitrogen dioxide (NO_2), a refined dispersion analysis to assess the effect of the proposed project and other sources on ambient air quality (compliance with national and Arizona ambient air quality standards [NAAQS/AAAQS]);
- An assessment of the proposed project's impacts to soils and vegetation;
- An assessment of the project's impacts to visibility;
- An assessment of regional population growth and associated emissions that may be caused by the proposed project; and
- An assessment of the proposed project's potential to affect increments, visibility, or other air quality related values (AQRVs) in nearby Class I areas.

At the Arizona Department of Environmental Quality's (ADEQ's) request, an air quality impact analysis was also performed to show compliance with sulfur dioxide (SO_2) NAAQS/AAAQS.

For a given pollutant, a Prevention of Significant Deterioration (PSD) increment is the maximum increase in concentration allowed above an established baseline concentration. Refined dispersion analyses were not performed to assess the effect of the proposed project and other sources on Class II increments of allowable deterioration in air quality (increment consumption) because only 1-hour NO_2 impacts exceeded a SIL and no increment has been promulgated for 1-hour NO_2.

The Bowie Power Station will be a minor source of hazardous air pollutants (HAPs), with total HAP emissions less than 25 tpy and emissions of each individual HAP less than 10 tpy. Modeling of HAPs and other noncriteria pollutants was not performed.

5.1 Site Description

The project site and surrounding areas are primarily agricultural. This area lies within the San Simon Valley, defined by the Pinaleno, Dos Cabezas, and Chiricahua Mountain ranges to the west of the site, and the Peloncillo Mountain range to the east. The San Simon Valley has a general northwest-to-southeast orientation, with a gentle slope upward from the northeast to the southwest. The nearest elevated terrain to the project site occurs in the Fisher Hills, located within the valley to the northwest. The leading edge of these hills is within 7 kilometers (km) of the site. The highest terrain feature within a radius of 30 km of the site is Government Peak (7,580 feet above mean sea level [ft msl]), located within the Dos Cabezas Mountain range. The site will be graded to a base elevation of approximately 3,737 ft msl (1,139 meters). The proposed location is in Township 12S, Range 28E, Section 28. The location of the site within the valley is shown in Figure 2-1.

5.2 Regional Climatology

The climate in the Bowie area can be characterized as mild and dry. Seasonal temperatures and precipitation totals observed in Safford, Arizona (approximately 53 km to the north) for the period 1951-1980 are shown in Table 5-1 (Gale 1985). The annual average temperature for the Safford area is 62.5 degrees Fahrenheit (ºF).

Table 5-1. Seasonal Temperatures and Precipitation

Season	Temperature (ºF)			Total Average Precipitation (inches)
	Maximum	Minimum	Average	
Spring	78.7	42.6	60.7	0.9
Summer	97.0	64.1	80.6	3.6
Autumn	80.7	46.5	63.7	2.3
Winter	61.3	29.0	45.1	1.9

Notes:

°F = Degrees Fahrenheit
Maximum = Mean daily maximum
Minimum = Mean daily minimum

5.3 Area Classification and Baseline Dates

The proposed project is located within 50 miles (mi) of the Arizona-New Mexico border, which makes New Mexico an affected state. Tribal lands within 50 km of the project's impact area are also generally treated as affected states and informed of the project so that they may provide comments. The nearest tribal land to the project area is the San Carlos Indian Reservation located approximately 75 km to the north and northwest. Other tribal lands in southern Arizona and New Mexico, including Tohono O'odham and Pascua Yaqui, both located in Pima County, Arizona, and Mescalero in Otero County, New Mexico, are located further from the proposed project site.

For a given pollutant, the baseline concentration represents the actual ambient concentration existing at the initiation of the PSD program in a given area. Two types of baseline dates have been established: major source baseline dates and minor source baseline dates. The major source baseline date identifies the point in time after which major sources affect available increment, while the minor source baseline date identifies the point in time after which actual emission changes from all sources (both major and minor) affect available increment. The amount of PSD increment that has been consumed within an area is determined from the actual emission increases and decreases that have occurred since the applicable baseline date.

The major source baseline dates are as follows:

- January 6, 1975, for SO_2 and PM_{10};
- February 8, 1988, for NO_2; and
- October 20, 2011, for $PM_{2.5}$.

The trigger dates are the dates after which a minor source baseline can be established for an area. The trigger dates are as follows:

- August 7, 1977, for SO_2 and PM_{10};
- February 8, 1988, for NO_2; and
- October 20, 2011, for $PM_{2.5}$.

The minor source baseline date in the Southeast Arizona Intrastate Air Quality Control Region for NO_x, SO_2, and PM_{10} is April 5, 2002. The baseline area for the project encompasses the counties of Cochise, Graham, Greenlee, and Santa Cruz. The applicable $PM_{2.5}$ minor source baseline date has not yet been set.

5.4 Ambient Data Requirements

A PSD permit applicant can satisfy the preconstruction monitoring requirements associated with the PSD permitting process by using data from existing monitors that are determined by ADEQ to be representative of background conditions in the affected area. On January 22, 2013, the US Court of Appeals for the DC Circuit issued an opinion granting the US Environmental Protection Agency's (EPA's) request to voluntarily remand the portion of a regulation establishing SILs for $PM_{2.5}$ and invalidating the portion of the regulation establishing the significant monitoring concentration (SMC) for $PM_{2.5.}$; the decision contained no holdings, and thus has no effect with respect to the SILs or SMCs for any other pollutant. Subsequently, on March 4, 2013, the EPA issued *Draft Guidance for $PM_{2.5}$ Permit Modeling* in light of the Court's decision. The draft guidance and all associated guidance relate exclusively to $PM_{2.5}$, and do not alter, impact, or otherwise change the ability of ADEQ to use and rely upon the SILs or SMCs for other pollutants. Also, neither the Court opinion nor the draft guidance have altered ADEQ's discretion to use representative data to satisfy the preconstruction monitoring requirements of PSD permitting. The Modeling Report (Appendix E) contains a detailed analysis of the representativeness of nearby existing monitoring data that was used in connection with the modeling. The conclusions of that analysis are described briefly in this section.

The *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA 1987) discuss the concept of "representative" air quality data. Use of the *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* has been upheld as appropriate by the EPA's Environmental Appeals Board (EAB), as has the use of representative data to satisfy the preconstruction monitoring requirements of PSD permitting.

The *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA 1987) provide that, with respect to location, the existing monitoring data should be representative of three types of areas: 1) the location(s) of maximum concentration increase from the proposed source or modification, 2) the location(s) of the maximum air pollutant concentration from existing sources, and 3) the location(s) of the maximum impact area (i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of the existing sources and the proposed new source). The Guidelines go on to state that if the proposed source will be constructed in an area that is generally free from the impact of other point sources and area sources associated with human activities, then monitoring data from a "regional" site may be used as representative data. Such a site could be out of the maximum impact area but must be similar in nature to the impact area. The Bowie Power Station will be located in an area with low population. Moreover, the Bowie Power Station location is not adjacent to other point sources and is situated such that it is not considered to be in a "multisource" area. As with much of rural southern Arizona, the surrounding land use is a mixture of undisturbed desert and agriculture.

In 2011, the National Association of Clean Air Agencies (NACAA) published a report from the NACAA $PM_{2.5}$ Modeling Implementation Workshop, titled *$PM_{2.5}$ Modeling Implementation for Projects Subject to National Ambient Air Quality Demonstration Requirements Pursuant to New Source Review* (NACAA 2011). A discussion from the Representative Background Concentrations Subgroup expands on the factors to be considered in determining whether a monitoring site is representative of the maximum impact area for a proposed source:

- Proximity to the source(s) modeled. In general, the nearest monitoring site is preferable. A monitoring site that is far from the source(s) modeled may be affected by the

secondary formation of $PM_{2.5}$ precursors that are emitted under much different circumstances.

- Similarity of the surrounding source(s). Sources in the vicinity of the monitor should be similar to those near the source(s) modeled. The background concentration should not be affected by major point sources that would not affect receptors in the vicinity of the source being permitted. But, the concentrations at a monitoring site that is impacted by suburban or industrial sources might be representative of the background in an area that has similar sources.
- Conservativeness of the background concentrations. The intent of any analysis is to ensure that it is "conservative" (i.e., ambient concentrations are overestimated). Thus, an effort should be made to select a background monitoring site where the measured concentrations are equal to or greater than those that would be measured were a monitor to be located in the vicinity of the source(s) to be modeled.

Although this guidance relates to modeling for $PM_{2.5}$, it is consistent with EPA's guidance and EAB decisions discussing the factors used in establishing whether particular data are "representative" generally with respect to any pollutant. ADEQ's *Draft Revised Modeling Guidelines* (August 2013; p. 34) further support the use of conservative data as background data. Thus, the NACAA guidance is referenced and used as support for the position that the data relied upon for each pollutant is "representative" such that is satisfies the preconstruction monitoring requirements of PSD permitting.

5.4.1 Ozone

Ambient ozone monitoring data from the nearby Chiricahua National Monument (NM) has been proposed and accepted by ADEQ as representative ozone data that meets the PSD preconstruction monitoring requirement. The Chiricahua NM monitor is located approximately 41 km to the south-southeast of the project. The ozone monitor is located at an elevation of 5,151 feet (the Bowie Power Station will be located at 3,737 feet elevation). It is the nearest location to the project where ozone is monitored and the only ozone monitoring location in Cochise County. Because ozone is a regional pollutant, the Chiricahua NM data are expected to be representative of the project site. Both the Bowie project and the Chiricahua NM are located in rural areas, far from major areas of ozone precursor emissions (i.e., Tucson, Phoenix, etc.). On April 30, 2012, EPA designated Cochise County attainment/unclassifiable with respect to the 2008 ozone NAAQS based on data from this monitor, along with an analysis of population density, emissions, and commuting patterns. ADEQ has concluded that Cochise County does not contribute to ambient air quality that does not meet the 8-hour ozone standard (ADEQ 2009).

5.4.2 Particulate Matter

Particulate matter ($PM_{2.5}$ and PM_{10}) data are also collected at the Chiricahua NM through the Interagency Monitoring of Protected Visual Environments (IMPROVE) program, monitored on a 1-in-3 day schedule. These data were proposed as representative data for $PM_{2.5}$ and PM_{10} in the Modeling Protocol prepared for this project (WREG 2013) and subsequently approved by ADEQ.

Local and regional emissions from upwind urban areas and rural sources can account for 50%-75% of total observed particulate matter concentrations. Generally, PM_{10} consists of 40%-60% $PM_{2.5}$, and the remainder is primarily locally generated, crustal/geological and biological material. In contrast, most of the observed $PM_{2.5}$ mass usually originates as precursor gases and, through various physiochemical processes, is transferred to the condensed phase as secondary particulate matter. (NARSTO 2004)

Particulate matter is composed of multiple chemicals, largely sulfate, organic carbon, and nitrate, in combinations that differ by geographic region. Non-coastal rural areas are dominated by sulfate, organic carbon, and black carbon, while nitrate-containing particles are important in parts of the west. Almost all sulfate originates from SO_2 oxidation mediated by ammonia. While 95% of SO_2 sources are anthropogenic, from fossil fuel combustion, the majority of ammonia sources are related to agricultural activities. Essentially all particle nitrate is derived from atmospheric oxidation of NO_x. The major anthropogenic source of NO_x is fossil fuel combustion. Organic carbon may be primary and/or secondary, of biogenic (vegetative material, biogenic gases, spontaneous forest fires) and anthropogenic (fossil fuel combustion, prescribed fires, cooking) origin. Black carbon originates as ultrafine or fine particles from primary sources during incomplete combustion of carbon-based fuels. (NARSTO 2004)

$PM_{2.5}$ concentrations tend to be highest in the central portions of urban areas, diminishing to background levels at the urban fringe. The typically smaller spatial variations of $PM_{2.5}$ compared to PM_{10} are consistent with the long atmospheric residence time of fine particles, which permits transport over distances of 10 to 1,000 km and leads to more uniform mass concentrations. PM_{10} concentrations are not spatially distributed smoothly because each monitoring site is strongly influenced by the degree of localized emissions of coarse particles. (NARSTO 2004; ADEQ 2009)

The Chiricahua NM monitoring location is the closest site at which $PM_{2.5}$ and PM_{10} data are recorded (41 km). Both the Chiricahua NM site and the proposed Bowie Power Station location are rural areas without significant nearby population. The surrounding land use in each case includes a mixture of desert and agriculture, both of which are sources of directly emitted $PM_{2.5}$ and PM_{10}. Other southeastern Arizona locations where $PM_{2.5}$ and/or PM_{10} are monitored are located over twice as far from Bowie and the surrounding land uses are different.

Both the Chiricahua NM and the Bowie Power Station site are potentially impacted by a number of point sources of directly emitted $PM_{2.5}$ and PM_{10}, as well as $PM_{2.5}$ precursor emissions (NO_x and SO_2). With respect to $PM_{2.5}$ precursors, the cumulative emissions profiles are almost identical and are dominated by emissions from the Apache Generating Station. For directly emitted $PM_{2.5}$ and PM_{10}, the Chiricahua NM monitoring site is slightly closer to the major particulate matter point sources in the region, rendering the monitoring data conservative relative to the Bowie Power Station location. As a result, the Chiricahua NM monitoring site may be considered representative of the Bowie Power Station impact area.

EPA has recently provided draft guidance on $PM_{2.5}$ modeling for New Source Review (EPA 2013). A secondary $PM_{2.5}$ analysis is required for the Bowie Power Station. This makes the Chiricahua NM IMPROVE data particularly valuable for use in this analysis because the data are speciated and fractions of the major components of fine mass, including sulfate, nitrate, organic carbon etc., are expected to provide useful reference information for a qualitative analysis of the Bowie Power Station's secondary $PM_{2.5}$ impacts.

5.4.3 Sulfur Dioxide

SO_2 emissions from the Bowie Power Station are below the significant emission rate for PSD and this pollutant is being modeled at the request of ADEQ, rather than as a required part of the PSD impact analyses. SO_2 is currently monitored at only a few locations in Arizona. Most locations were sited to

capture maximum impacts from large SO_2 point sources, including smelters and coal-fired power plants. As such, these monitors would not be representative of expected SO_2 concentrations in the Bowie area, where the nearest major point source of SO_2 (Apache Generating Station) is located approximately 50 km away.

SO_2 is monitored at one location in the Tucson metropolitan area in Pima County, approximately 80 mi to the west of the Bowie location. Unlike most other SO_2 monitoring sites in Arizona, the Pima County monitor was not located to capture maximum impacts from a specific point or group of sources but instead represents general population exposures to this pollutant. According to the Pima County Department of Environmental Quality (PDEQ 2011), ambient concentrations of SO_2 in Tucson have historically remained well below all federal standards and in recent years have been extremely low. SO_2 was monitored for a number of years at the 22nd and Craycroft location but that site was discontinued in December 2010, after an SO_2 trace monitor was added at the Children's Park NCore location. Although slightly older, three years of SO_2 data from the 22nd and Craycroft (2008-2010) site were proposed and accepted by ADEQ as representative monitoring data because of the shorter period of record from the Children's Park location. These data are expected to be conservative relative to the Bowie Power Station location because of possible influence from the Irvington Generating Station (156 MW capacity coal), located 5.4 km from the 22nd and Craycroft monitor site. While the Bowie site is potentially impacted by a larger coal fired power plant (Apache Generating Station, ~400 MW coal), it is further away (50 km).

5.4.4 Carbon Monoxide

CO is another pollutant that is only monitored at a few sites in Arizona. The closest CO monitoring locations are in Pima County (Tucson metropolitan area). PDEQ monitors CO at five locations. Motor vehicles are the primary source of CO nationally as well as in the Tucson area. In spite of increased vehicular traffic, CO concentrations in Pima County have declined in the past three decades. This has been attributed to the use of cleaner burning oxygenated fuels, fuel efficient computer controlled vehicles, locally adopted Clean Air and Travel Reduction Programs, and various local traffic control measures. No exceedances of the CO NAAQS have been recorded in Tucson since 1988.

According to EPA, the entire country now has air quality that meets current CO standards. Most sites have measured concentrations below the national standards since the early 1990s and improvements in motor vehicle emissions controls have contributed to significant reductions in ambient concentrations since that time. National data show a 73% decrease in CO (8-hour concentrations) between 1990 and 2010 and a 54% decrease between 2000 and 2010.

Because Tucson is a larger metropolitan area with higher traffic levels than the Bowie Power Station site, other CO monitoring sites in nearby states were examined to identify sources of monitoring data that are representative of the rural Bowie area. The only significant source of CO emissions in the immediate vicinity of Bowie is Interstate 10 (I-10), which has measured annual average daily traffic (AADT) volumes of 11,000-13,000 vehicles per day in recent years.

CO monitoring locations in Arizona, New Mexico, Colorado, Wyoming, Utah, and southern California were examined to identify sources of representative monitoring data for use in connection with the Bowie PSD permitting process. CO concentrations would be expected to be influenced by climate (colder areas have poorer winter dispersion, more fuel is burned to start motor vehicles, and emission control devices on vehicles operate less efficiently in cold weather), elevation (less oxygen in the air means less complete combustion, although this is mitigated in some areas by oxygenated fuel requirements), and population and traffic volumes on nearby roads, both of which relate to probable mobile source emissions. As a result of these factors, candidate sites were chosen that were located in cities smaller than Tucson or outside cities, that were inland, and that were near paved roadways, and that were therefore similar to the conditions facing the Bowie Power Station. This resulted in a list of 18 sites

that were examined in more detail. The most recent three years of CO monitoring data (if available) were collected for these sites.

Population ranged from over 900,000 in Tucson to a site 26 kilometers from a town of 12,500. Elevations ranged from 89 meters to over 1,900 meters. Distances to the nearest road and to the largest road within a few kilometers also varied. The climate varied from hot, desert locales to cold winter areas.

All sites show CO concentrations well below the NAAQS. Over the most recent three years, all sites show 1-hour CO concentrations below 10% of the NAAQS, and 8-hour concentrations are no more than 25% of the NAAQS. As demonstrated by the varied climate, population, elevation, and nearby traffic at the 18 stations analyzed, CO concentrations can be expected to be generally low and relatively insensitive to variations in population or traffic beyond the immediate vicinity of the monitor.

While it would be reasonable to select any of these stations as having "representative" data, based on the factors found in EPA guidance, NACAA guidance, and relevant EAB decisions, the CO monitoring location identified as most representative of the Bowie Power Station location is located at 22nd and Craycroft in Pima County. This site is one of the oldest in the Pima County monitoring network, originally established in 1973, and has operated continuously to the present. The site is situated in a predominately residential area with commercial activity lining nearby arterial routes.

The 22nd and Craycroft monitor and the other Tucson monitors are those in closest proximity to Bowie (approximately 80 mi west of Bowie). The climate is similar and the monitor is located at an elevation that is only a few hundred meters below that of Bowie, both factors that influence CO emissions.

Traffic is the primary CO source at each location. Local traffic is more important in determining representativeness than traffic over a larger area. The *Integrated Science Assessment for Carbon Monoxide* (ISA; EPA 2010c) cites studies showing that CO concentrations decrease sharply, even exponentially, with downwind distance from a highway. The traffic monitor closest to the 22nd and Craycroft CO monitor has a traffic count of approximately 20,000 AADT vs 11,000-13,000 on I-10 at Bowie. In each case, the highway being measured is approximately 4 km from the CO monitoring site.

The 22nd and Craycroft monitor is considered a "neighborhood" scale monitor. The ISA notes that neighborhood scale CO monitors are sited to measure representative concentrations within a 0.5-4.0 km radius and, "For the [Code of Federal Regulations]-defined neighborhood scale monitoring, the minimum monitor distance from a major roadway is directly related to the average daily traffic counts on that roadway, to ensure that measurements are not substantially influenced by any one roadway.

It is expected that the CO concentrations at the 22nd and Craycroft monitor would be conservative relative to Bowie simply because of the larger urban area it is located in.

Use of data from a monitor site that is not adjacent or in the immediate vicinity of the source is appropriate where, as here, the source is in a rural and remote area and not located in a multisource area. The 22nd and Craycroft monitor has been identified as the most representative due to the similarities in terrain, meteorological conditions, and proximity to comparable traffic concentrations and has been approved by ADEQ for use in the modeling analyses for the proposed Bowie Power Station.

5.4.5 Nitrogen Dioxide

In Arizona, NO_2 has only been monitored in urban areas such as Tucson and Phoenix, which would not be representative of NO_2 concentrations in the project area. Consequently, NO_2 ambient air quality data from Deming, New Mexico was proposed and approved by ADEQ as representative monitoring data for use in a previous permit application for the Bowie Power Station. Deming is a city of around 15,000 located due east of Bowie along I-10, approximately 104 mi (168 km) from Bowie. NO_2 data have been collected at this location since July 2006.

Both Deming and the Bowie location are surrounded by a mixture of moderate to large point sources of NO_x emissions, which are detailed in Appendix E. In addition, the 1-hour NO_2 NAAQS is largely focused on concerns about short-term impacts from NO_x emissions due to heavy traffic and traffic hot spots. Both the Bowie Power Station and the Deming monitor are located near a major Interstate highway, I-10. The Deming monitor is located approximately 2 km from I-10, while the Bowie Power Station will be located approximately 4 km from I-10. Traffic volume on the portion of I-10 that runs through Bowie, Arizona is slightly lower than the link that runs through Deming, New Mexico, based on the most recent data available.

NO_x sources in the vicinity of the Deming monitor, along with closer proximity to a major highway, and a larger local population suggest that the Deming monitor provides a representative but conservative estimate of background NO_2 in the vicinity of Bowie.

5.4.6 Post-Construction Monitoring

Post-construction monitoring is required at the discretion of the Director. No post-construction monitoring is proposed for the project at this time.

5.5 Meteorological Monitoring

Bowie Power Station, LLC began collecting meteorological data on the proposed plant site in late April 2001. A 12-month dataset has been approved by ADEQ for use with AERMOD for modeling impacts within 50 km of the plant. The data have been reprocessed using the most recent version of the AERMOD Meteorological Preprocessor (AERMET; 12345).

Surface data from the Safford, Arizona, airport, located approximately 53 km north of the project site, were obtained from the National Climatic Data Center (NCDC). Cloud cover data from Safford were used in the meteorological data processing rather than on-site solar radiation data. The Safford Municipal Airport Station is the closest station to Bowie that collects cloud cover data. Further, Safford and Bowie are in similar topographic settings, both being located within the San Simon Valley, and share similar climatology.

The closest National Weather Service (NWS) station to the project site that routinely performs upper air soundings is the NWS station in Tucson. Tucson International Airport is located approximately 138 km to the west-southwest of the project site. Sounding data were downloaded from the NCDC Web site for 2001-2002. Data were extracted from the upper air and surface files for the appropriate time period and read from the on-site data file, and then merged in AERMET.

Surface characteristics were defined by sector and seasons based on aerial photographs and land use data around the project site. Geo-registered land use and land cover files were obtained from the US Geological Survey and the 1992 National Land Cover Dataset (NLCD) data files were used as input to AERSURFACE along with the sector information. The site is surrounded by desert shrubland and cultivated fields. The seasonal surface characteristics within the appropriate areas were determined in AERSURFACE and those geophysical values were input to the Stage 3 AERMET processing.

5.6 Background Concentrations

Background sources include all sources of air pollution other than those explicitly modeled (i.e., the proposed project, and those sources identified as "nearby" sources). Typically the impacts of non-nearby background sources are accounted for by using appropriate, monitored air quality data (i.e., a background concentration).

Title 40 of the Code of Federal Regulation (CFR), Part 50, Appendix W, Section 8.2 discusses requirements for background air quality concentrations that are "an essential part of the total air quality concentration to be considered in determining source impacts." Appendix W indicates, "Typically, air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration." For isolated single sources, such as the proposed Bowie Power Station, two options are presented: 1) Use air quality data collected in the vicinity of the source to determine the background concentrations for the averaging times of concern, or 2) If there are no monitors located in the vicinity of the source, a "regional site" may be used to determine background. A "regional site" is one that is located away from the area of interest but it impacted by similar natural and distant man-made sources.

For use in modeling compliance for 1-hour NO_2, EPA suggests using background NO_2 data that vary by season and hour of the day. The 98th percentiles of the daily maximum hourly NO_2 data from the Deming monitor for 2010-2012 were averaged by season and hour of day for use in the modeling analysis in accordance with "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard," March 1, 2011 (EPA 2011h). The proposed background concentrations, based on the representative monitors identified in Section 5.4, are shown in Table 5-2.

5.7 Modeling Analysis Design

Air quality impacts in the Class II areas surrounding the Bowie Power Station were determined with the most recent version of the AMS/EPA Regulatory Model (AERMOD; 12345). Except for the treatment of NO_x to NO_2 conversion, AERMOD was used with regulatory default options.

A receptor grid, or network, defines the locations of predicted air concentrations that are used to assess compliance with the relevant standards or guidelines. All coordinates used in the modeling are referenced to North American Datum 1983 (NAD83). The network used Cartesian (X, Y) receptors.

The following receptor network was used for this analysis:

- 25-m spaced receptors along the process area boundary;
- 100-m spaced receptors out to 1 km from the process area boundary;
- 250-m spaced receptors from beyond 1 km to 3 km from the process area boundary;
- 500-m spaced receptors from beyond 3 km to 10 km from the process area boundary;
- 1,000-m spaced receptors from beyond 10 km to 25 km from the process area boundary; and
- 2,500-m spaced receptors from beyond 25 km to 50 km from the process area boundary.

Figure 5-1 shows the process boundary receptors and the close-in receptor grid. The modeling protocol noted that a refined receptor grid would be defined around any impact point exceeding 90% of an ambient standard or significant impact level, where the Bowie Power Station contributed at least 3% of the total impact. None of the modeling results met these criteria; therefore, no refined receptor grids were defined.

Table 5-2. Background Concentrations

Pollutant	Averaging Period	Station Location/ID	Data Used	Background Value
PM_{10}	24-hour	Chiricahua NM	Average of maximum values 2009-2011	43 μg/m^3
	Annual		Average 2009-2011	8.3 μg/m^3
$PM_{2.5}$	24-hour	Chiricahua NM	Average of 2009-2011 98th percentile values	9.0 μg/m^3
	Annual		Average 2009-2011	3.5 μg/m^3
CO	1-hour	Pima County, 22nd and Craycroft	Maximum 2010-2012	2,414 μg/m^3
	8-hour		Maximum 2010-2012	1,264 μg/m^3
NO_2	1-hour	Deming, New Mexico SLAMS station	Average of 2010-2012 98th percentile values	Varies by season and hour of day. See Table 3-5
	Annual		Maximum 2010-2012	8.6 μg/m^3
SO2	1-hour	Pima County, 22nd and Craycroft	Average of 2008-2010 99th percentile values	22.6 μg/m^3
	3-hour		Maximum 2008-2010	37.7 μg/m^3
	24-hour		Maximum 2008-2010	10.5 μg/m^3
	Annual		Maximum 2008-2010	2.3 μg/m^3
Ozone	8-hour	Chiricahua NM	Average 2010-2012 4th high	73 ppb

Notes:

CO = Carbon monoxide
NM = National Monument
NO_2 = Nitrogen dioxide
PM_{10} = Particulate matter less than 10 micrometers
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers
ppb = Parts per billion
μg/m^3 = Micrograms per cubic meter

Receptors were modeled with terrain elevations interpolated from US Geological Survey (USGS) National Elevation Dataset (NED) data. The downloaded NED data have been processed in AERMAP (version 11103). The extent of the domain is sufficient to capture all necessary critical hill height information for AERMOD.

5.8 Source Characterization

The primary emission sources associated with this project are the two combined-cycle combustion turbines and the cooling tower. Other emission sources include a natural gas-fired auxiliary boiler and a diesel-fired emergency fire pump. The evaporation ponds will be a negligible source of fugitive VOC emissions and were not modeled.

The pollutants that may be emitted by the proposed project are subject to standards or guidelines with differing averaging periods. The averaging periods that were modeled and the emission scenarios that needed to be developed for each group of pollutants are shown in Table 5-3.

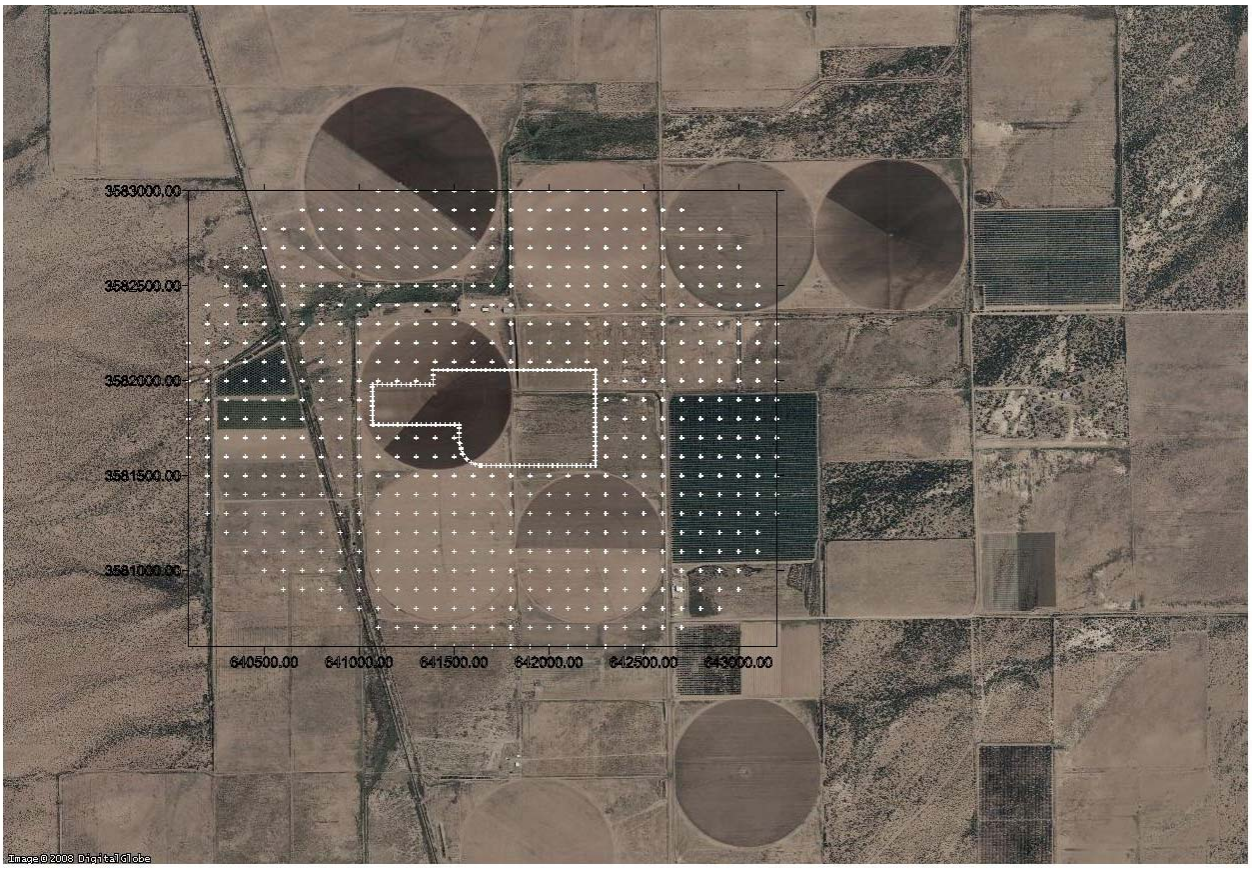

Figure 5-1. Close-in Receptor Grid

Table 5-3. Averaging Periods Modeled for Each Pollutant

Pollutant	Averaging Period				
	1-hour	3-hour	8-hour	24-hour	Annual
NO_x	▸ NAAQS ▸ Soils and vegetation impacts	NA	NA	▸ Visibility analysis ▸ Secondary $PM_{2.5}$ impacts	▸ NAAQS/AAAQS ▸ Class I and II increments ▸ Soils and vegetation impacts ▸ Nitrate deposition
CO	▸ NAAQS/AAAQS ▸ Soils and vegetation impacts	NA	▸ NAAQS/ AAAQS ▸ Soils and vegetation impacts	NA	NA
SO_2	▸ NAAQS/AAAQS	▸ NAAQS/AAAQS	NA	▸ NAAQS/AAAQS ▸ Visibility analysis ▸ Secondary $PM_{2.5}$ impacts	▸ NAAQS/AAAQS
PM_{10}[a]	NA	NA	NA	▸ NAAQS/AAAQS ▸ Class I and II increments ▸ Visibility analysis ▸ Soils and vegetation impacts	▸ NAAQS/AAAQS ▸ Class I and II increments ▸ Soils and vegetation impacts
$PM_{2.5}$	NA	NA	NA	▸ NAAQS/AAAQS ▸ Class I and II increments ▸ Soils and vegetation impacts ▸ Secondary $PM_{2.5}$ impacts	▸ NAAQS/AAAQS ▸ Class I and II increments ▸ Soils and vegetation impacts

[a] 1-month average was also modeled for PM_{10} from the cooling towers for use in the soils and vegetation impact analysis.

Notes:

AAAQS = Arizona ambient air quality standard
CO = Carbon monoxide
NA = Not applicable
NAAQS = National ambient air quality standard
PM_{10} = Particulate matter less than 10 micrometers
NO_x = Oxides of nitrogen
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers
SO_2 = Sulfur dioxide

For combustion turbines, such as those used for the proposed project, criteria pollutant emissions vary with load, ambient temperature, and with whether or not duct firing is in use during a given time period.

Turbine emissions profiles also vary during startup and shutdown. In general, NO_x, CO, and VOC emissions are higher during a startup or shutdown than during normal operations, while SO_2 and PM_{10} emissions are the same or lower. A cold or warm start will produce higher emissions of NO_x, CO, and VOC than a shutdown event. A cold or warm start (of both turbines) will take approximately one

hour with the “fast start” configuration, while a hot start will take 30 minutes. Shutdown takes approximately one-quarter an hour.

Duct burner emissions do not vary with ambient temperature, nor do the duct burners operate at partial loads. The duct burners will burn natural gas.

Annual turbine and duct burner emissions were calculated based on an average annual ambient temperature of 59°F. The turbine and duct burner annual emission calculations are based on a 95% capacity factor for the turbines, 4,224 hours of duct firing, 325 hours of startup, and 91.25 hours of shutdown for each turbine/duct burner pair.

For the combustion turbines, exit temperature and exit velocity will vary slightly with whether or not the duct burners are operating, during startup and shutdown, with load, and with ambient temperature. Screening analyses were used to determine the worst-case dispersion conditions that will lead to the highest impacts for a given emission rate and operating scenario.

For CO, the exhaust parameters modeled represented a “worst-case” profile of possible parameters; that is, the worst-case dispersion parameters were paired with worst-case emissions to return maximum modeled concentrations. For the other pollutants and averaging periods modeled, more realistic combinations of emissions and stack parameters were used.

The emission and stack parameter (exit velocity and temperature) scenarios used for the turbines/duct burners for short-term averaging periods are shown in Table 5-4.

For the pollutants and averaging periods where stack parameters and emissions (as applicable) were varied seasonally, 10˚F parameters/emissions were used for months with average minimum temperatures below freezing (December and January), 102˚F parameters/emissions were used for months with average maximum temperatures higher than 90˚F (June through September), and 59˚F parameters/emissions were used for the remaining months.

The following were modeled as point sources using expected physical stack heights, exit velocities, temperatures, and diameters:

- Auxiliary boiler;
- Cooling tower cells; and
- Fire pump.

All point sources are within good engineering stack height and were modeled at their physical height. Stack parameters are shown in Table 5-5.

Table 5-4. Turbine/Duct Burner Scenarios Modeled[a]

Pollutant	Averaging Period: 1-hour, 3-hour		8-hour		24-hour	
	Emissions	Stack Parameters[b]	Emissions	Stack Parameters[b]	Emissions	Stack Parameters[b]
NO_x	Hot start, varied seasonally[c]	Startup parameters, varied seasonally[c]	NA		Visibility – Three hot starts, two shutdowns, remaining hours normal operation maximum emission rate (100% load with duct firing, 10°F ambient)	Visibility - Weighted average based on startup and worst-case normal operation parameters
CO	Hot start, 10°F ambient	Minimum compliance load, 59°F ambient	Hot start, 10°F ambient	Minimum compliance load, 59°F ambient	NA	
SO_2	100% load with duct firing, varied seasonally[c]	100% load with duct firing, varied seasonally[c]	NA		100% load with duct firing, varied seasonally[c]	100% load with duct firing, varied seasonally[c]
	Startup, varied seasonally[c]	Startup, varied seasonally[c]			Minimum compliance load, varied seasonally	Minimum compliance load, varied seasonally
					Visibility - Matched to NO_x emission scenario	Visibility - Matched to NO_x stack parameter scenario
$PM_{10}/PM_{2.5}$	NA		NA		100% load with duct firing, varied seasonally[c]	100% load with duct firing, varied seasonally[c]
					Minimum compliance load, varied seasonally	Minimum compliance load, varied seasonally
					Visibility - Matched to NO_x emission scenario	Visibility - Matched to NO_x stack parameter scenario

[a] In some cases the emission and stack parameter scenario that will yield the highest impacts is not obvious and more than one scenario was modeled. Scenarios listed are for comparison with ambient standards/significant impact levels, unless otherwise indicated.
[b] Stack temperature and exit velocity.
[c] Emissions and/or stack parameters vary with ambient temperature.

Notes:

CO	=	Carbon monoxide
NA	=	Not applicable
NO_x	=	Oxides of nitrogen
PM_{10}	=	Particulate matter less than 10 micrometers
$PM_{2.5}$	=	Particulate matter less than 2.5 micrometers
SO_2	=	Sulfur dioxide

Table 5-5. Stack Parameters

Source	Stack Height (m)	Stack Diameter (m)	Temperature (K)	Velocity (m/s)
Turbine/Duct Burner	54.86	5.49	Varies	Varies
Auxiliary Boiler	13.7	0.76	422.04	15.24
Fire Pump	10.67	0.13	809.26	65.23
Cooling Tower[a]	14.00	10.00	294.26	8.59

[a] Each cell

Notes:

K	=	Kelvin
m	=	Meters
m/s	=	Meters per second

5.9 Building Wake Downwash

Stack exhaust has the potential of being influenced by building wakes, which in effect "wash down" the plume, causing increased ground-level concentrations. Downwash parameters for the Bowie Power Station structures have been determined with the EPA Building Profile Input Program (BPIP)-PRIME. Each structure corner coordinate and elevation was used as input to the program and wind direction-specific building parameters have been output in a format used by AERMOD. Only those buildings with the likelihood to influence emission sources (i.e., within 5L in accordance with the good engineering practice (GEP) stack height regulations in 40 CFR 51.100) have been included in the analysis. The location of emission sources and structures on the site is shown in Figure 5-2.

5.10 Preliminary Analysis

The dispersion modeling analysis required for major sources subject to PSD review typically involves two phases. The objective of the first phase is to perform a conservative, screening-level analysis (preliminary analysis) of the impacts of the proposed project alone, to determine whether the predicted impacts are expected to be significant. If no significant impacts are predicted for a particular pollutant, no further analysis is required for that pollutant.

If significant ambient impacts are predicted, then a full impact analysis must be completed for that pollutant. This requires conducting a NAAQS/AAAQS analysis for the pollutant, in which other emission sources in the area are modeled, and conducting a PSD increment analysis for the pollutant that incorporates emissions from other increment-affecting sources in the area.

The Plume Volume Molar Ratio Method (PVMRM) option in AERMOD was used to account for the after stack conversion of emitted NO_x to downwind NO_2. This option requires an hourly ozone data file. Hourly ozone data from the Chiricahua NM monitoring station matching the Bowie meteorological data set time period were used.

The use of PVMRM also requires use of an in-stack ratio for each source. The California Air Pollution Control Officers Association (CAPCOA) has produced a guidance document titled "Modeling Compliance of the Federal 1-Hour NO_2 NAAQS" (CAPCOA 2011) that includes recommended in-stack ratios in Appendix C. The following recommended in-stack NO_2/NO_x ratios were used for the Bowie sources:

- The natural gas boiler default factor of 0.1 was used for the auxiliary boiler;
- The diesel internal combustion engine default factor of 0.2 was used for the fire pump; and

- The GE natural gas turbine recommended ratio of 0.091 was used for the turbines/HRSGs.

In accordance with EPA's guidance on modeling intermittent sources (EPA 2011h), the fire pump was not included in the 1-hour SO_2 or NO_2 modeling but was included in modeling all other pollutants and averaging periods.

A screening analysis was conducted for CO, NO_2, SO_2, and $PM_{10}/PM_{2.5}$. The highest predicted impact at any point on the receptor grid has been used for comparison with the modeling SILs identified in Table 5-6.

Table 5-6 summarizes the results of the preliminary analysis. All modeled impacts for CO, SO_2, annual NO_2, and $PM_{10}/PM_{2.5}$ were below the SILs. Therefore, the project will have insignificant impacts for these pollutants and averaging periods and full/cumulative analyses will be performed. The maximum 1-hour NO_2 concentration exceeded the SIL; therefore, a full/cumulative analysis was conducted for that pollutant and averaging period.

5.11 Secondary $PM_{2.5}$

Due to the potentially large contributions of secondary $PM_{2.5}$ to total ambient $PM_{2.5}$ concentrations, EPA has provided draft guidance that includes analyses of both primary and secondary $PM_{2.5}$ from proposed new major sources, such as the Bowie Power Station (EPA 2013). AERMOD was used to analyze primary $PM_{2.5}$ emissions, while potential secondary $PM_{2.5}$ from emissions of precursors (NO_x, SO_2) from the project was assessed in a qualitative fashion.

In determining whether a full analysis is needed for $PM_{2.5}$, EPA's draft guidance suggests that the applicable SIL value from the vacated sections (*Sierra Club v. EPA*, No. 10-1413) of 40 CFR 50.166(k)(2) and 52.21(k)(2) should only be used if the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations are greater than the SIL:

- Annual $PM_{2.5}$ NAAQS: 12 micrograms per cubic meter ($\mu g/m^3$); SIL 0.3 $\mu g/m^3$. Measured background (2009-2011 average at Chiricahua NM) is 3.5 $\mu g/m^3$. Therefore, the difference is larger than the SIL and the numeric value of the SIL may be appropriate for use in determining whether a source may forego cumulative modeling.
- 24-hour $PM_{2.5}$ NAAQS: 35 $\mu g/m^3$; SIL 1.2 $\mu g/m^3$. Measured background (2009-2011 98th percentile average at Chiricahua NM) is 9.0 $\mu g/m^3$. Therefore, the difference is larger than the SIL and the numeric value of the SIL may be appropriate for use in determining whether a source may forego cumulative modeling.

$PM_{2.5}$ monitoring data from the Chiricahua NM is expected to be representative of the contribution of existing sources to $PM_{2.5}$ concentrations in the Bowie Power Station impact area. Speciated $PM_{2.5}$ data from the Chiricahua NM IMPROVE monitoring system show that the major components of $PM_{2.5}$ (excluding periodic contributions from wildfires) are ammonium sulfate (37%), soil (33%), and organic matter (25%). Ammonium nitrate provides 6% of total $PM_{2.5}$ at this location.

Examination of the maximum direct impacts of $PM_{2.5}$ emitted by the Bowie Power Station shows that the highest annual and 24-hour impacts occur close to the facility (<1 km from the turbine stacks). A similar pattern is observed for the 24-hour scenarios. Maximum impacts again occur within <1 km of the turbine stacks. Maximum short-term impacts occur on breezy days with lower wind speeds at night. Daytime stability conditions are fairly neutral. The 10 maximum modeled 24-hour impacts all occurred in fall (September-November).

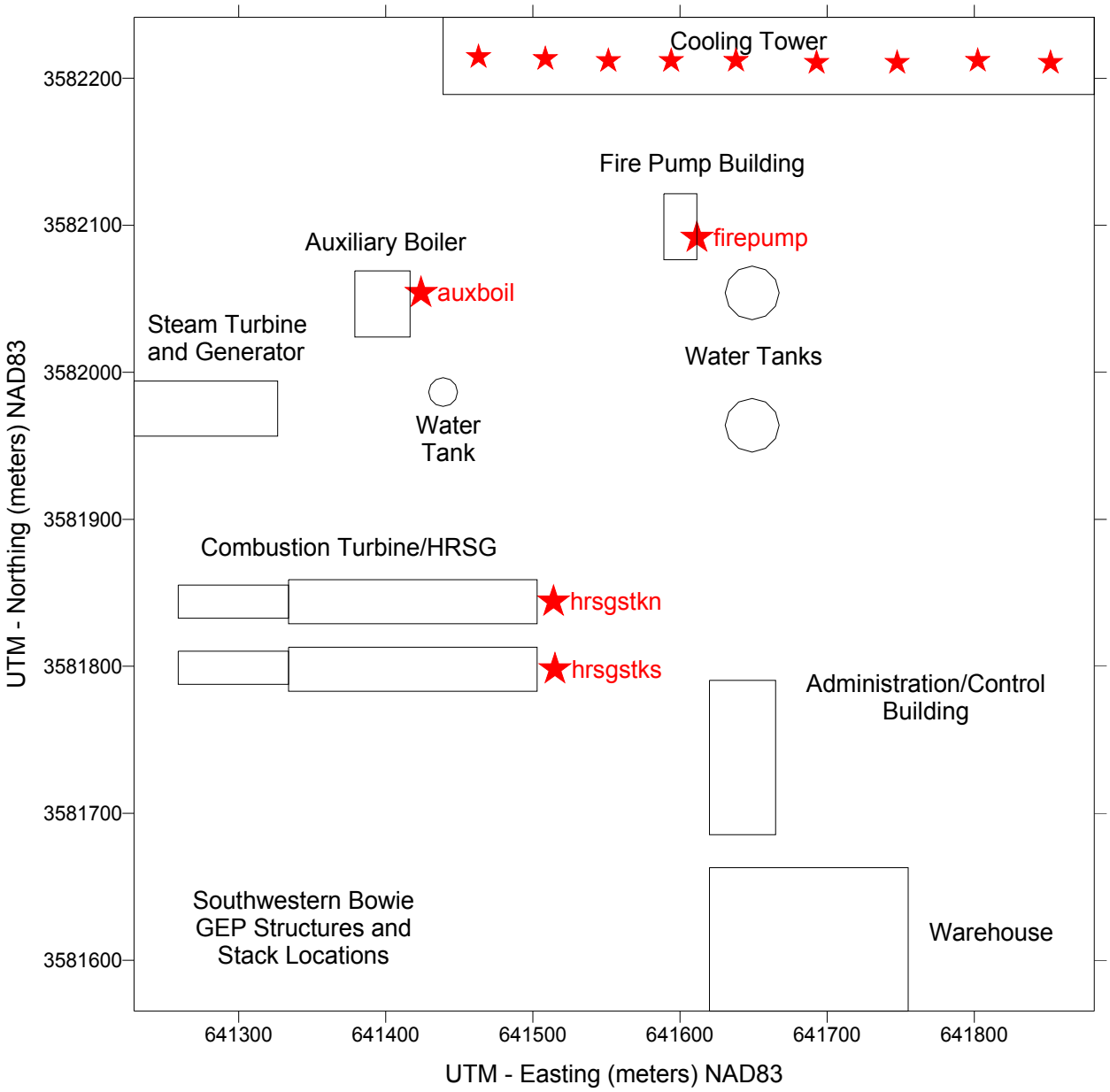

Figure 5-2. Location of Major Emission Points and Structures

Table 5-6. Results of Preliminary Class II Analysis

Averaging Period/ Pollutant	Maximum Predicted Impact ($\mu g/m^3$)	Class II Modeling Significance Level ($\mu g/m^3$)	Significant Monitoring Level ($\mu g/m^3$)
1-hour NO_2	84.34	7.5	NA
Annual NO_2	0.27	1	14
1-hour SO_2	5.13	8	NA
3-hour SO_2	1.75	25	NA
24-hour SO_2	0.35	5	NA
Annual SO_2	0.06	1	NA
24-hour PM_{10}	1.81	5	10
Annual PM_{10}	0.26	1	NA
24-hour $PM_{2.5}$	1.07	1.2	NA
Annual $PM_{2.5}$	0.16	0.3	NA
1-hour CO	439.4	2,000	NA
8-hour CO	85.10	500	575

Notes:

$\mu g/m^3$ = Micrograms per cubic meter
CO = Carbon monoxide
NA = Not applicable
NO_2 = Nitrogen dioxide
PM_{10} = Particulate matter less than 10 micrometers
$PM_{2.5}$ = Particulate matter less than 2.5 micrometers

Calpuff was used to evaluate sulfate and nitrate impacts from the Bowie Power Station. Seasonal short-term and an annual scenario were modeled. As noted above, maximum $PM_{2.5}$ impacts from the facility occur within 1 km of the turbine stacks. In contrast, maximum sulfate and nitrate concentrations, on both a short-term and annual basis, occur further downwind. Maximum annual and short-term sulfate impacts were projected to occur about 6.9 km downwind from the source. For nitrate, the location of maximum impacts varied with the scenario. On an annual basis, maximum nitrate occurred 11.6 km from the facility. Short-term nitrate maxima ranged from 3.6-11.6 km from the facility. As a result, maximum direct $PM_{2.5}$ impacts from the Bowie Power Station will not directly add to maximum secondary $PM_{2.5}$ impacts from the facility; instead, lower combined impacts would be expected.

On an annual average basis, contributions to annual $PM_{2.5}$ concentrations at Chiricahua NM are highest in the summer and spring, with lower contributions in winter and fall. The distributions of the components of fine particles also differ by season, with ammonium nitrate showing maximum contributions in the winter, soil and sea salt showing maximum contributions in the spring, ammonium sulfate elemental carbon, and organic carbon showing maximum contributions in the summer, and none of the constituents showing maximum contributions in the fall.

With respect to maximum short-term $PM_{2.5}$ concentrations, the five highest concentrations from each year in the 2009-2011 Chiricahua NM dataset were examined. Maximum 24-hour $PM_{2.5}$ concentrations occurred most often in summer (60%) and spring (33%), with only 7% of maximum 24-hour concentrations occurring in winter and no maximum concentrations occurring in fall. This is in contrast to Bowie's direct $PM_{2.5}$ maximum concentrations, which were all predicted to occur during the fall season. Relative to short-term maximum impacts from directly emitted $PM_{2.5}$ from the Bowie Power Station, maximum 24-hour $PM_{2.5}$ concentrations at Chiricahua NM occur at lower wind speeds and under somewhat less stable daytime conditions.

Source apportionment data from the Western Regional Air Partnership (WRAP) Technical Support System (TSS), developed through regional CAMx modeling to identify the sources and regions contributing to regional haze in the WRAP region, indicate that less than 10% of sulfate at Chiricahua NM on an annual basis is from Arizona sources, in spite of the fact that Chiricahua NM is located less than 50 km from a large source of SO_2 emissions (Apache Generating Station; 13,500 tons per year [tpy] SO_2 emissions). Based on 2008 modeling data, Arizona SO_2 emissions totaled approximately 85,000 tpy. It is unlikely that a relatively small source of SO_2 emissions such as the Bowie Power Station (approximately 30 tpy or 0.035% of Arizona emissions) would appreciably increase $PM_{2.5}$ from ammonium sulfate in the project area.

TSS source apportionment modeling shows that approximately 29% of nitrate at Chiricahua NM is derived from the Arizona source region. But nitrate is a relatively minor component of total $PM_{2.5}$ at Chiricahua NM, contributing only 6% of $PM_{2.5}$, and, as with SO_2, the monitoring location is located less than 50 km from a large source of NO_x emissions (Apache Generating Station, 14,000 tpy NO_x). Arizona NO_x emissions totaled approximately 293,000 tpy based on 2008 modeling scenarios. Again, it appears that an additional 139 tpy NO_x (0.048%of Arizona emissions) from the Bowie Power Station would be unlikely to appreciably increase $PM_{2.5}$ from ammonium nitrate in the project area.

Maximum direct $PM_{2.5}$ impacts from to the Bowie Power Station are below the 24-hour and annual SILs and, therefore, well below the NAAQS levels. It is unlikely that secondary $PM_{2.5}$ from the Bowie facility would cause or contribute to an exceedance of the NAAQS for the following reasons:

- Maximum impacts of directly emitted $PM_{2.5}$ from the Bowie Power Station occur close to the facility (< 1 km) on both a short-term and annual basis. In contrast, sulfate and nitrate that form from precursor emissions from the Bowie Power Station occur farther downwind (3.6-11.6 km from the facility) as the chemical reactions occur during transport.
- Maximum 24-hour $PM_{2.5}$ impacts from the Bowie Power Station occur during the fall season. In contrast, maximum background $PM_{2.5}$, as measured at Chiricahua NM, occurs largely in summer and spring and not during the fall season.
- Chiricahua NM $PM_{2.5}$ consists primarily of ammonium sulfate (37%), soil (33%), and organic carbon (25%). Ammonium nitrate is a small component (6%). In contrast, the Bowie Power Station is a small source of SO_2 (30 tpy), the primary ammonium sulfate precursor.
- Meteorological conditions that lead to maximum short-term $PM_{2.5}$ from the Bowie Power Station (breezy, stable) differ somewhat from the conditions that lead to maximum short-term $PM_{2.5}$ at Chiricahua NM (lower wind speeds, less stable conditions).
  - Less than 10% of sulfate at Chiricahua NM on an annual basis is from Arizona sources. Arizona SO_2 emissions totaled approximately 85,000 tpy. It is unlikely that a relatively small source of SO_2 emissions such as the Bowie Power Station (approximately 30 tpy or 0.035% of Arizona emissions) would appreciably increase $PM_{2.5}$ from ammonium sulfate in the project area.
  - Approximately 29% of nitrate at Chiricahua NM is derived from the Arizona source region. Nitrate is a relatively minor component of total $PM_{2.5}$ at Chiricahua NM. Arizona NO_x emissions total approximately 293,000 tpy. An additional 139 tpy NO_x (0.048% of Arizona emissions) from the Bowie Power Station would be unlikely to appreciably increase $PM_{2.5}$ from ammonium nitrate in the project area.

5.12 Full Impact Analysis

A full impact analysis was performed to determine the Bowie project's compliance with the 1-hour NO_2 NAAQS. Impacts above the SIL were predicted out to approximately 50 km from the Bowie Power Station. Therefore, sources were examined that are within approximately 100 km for possible inclusion in the cumulative analysis.

Appendix W suggests that nearby and other sources that should be included in the modeled inventory for a full analysis are those that establish "a significant concentration gradient in the vicinity of the source." Appendix W also suggests that the number of such sources is expected to be small."

EPA's March 1, 2011 guidance document, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard" (EPA 2011h) further discusses the concept of "significant concentration gradient" and notes that "... the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 kilometers of the project location in most cases." The guidance suggests tools to inform a case-specific exercise of professional judgment to determine which sources should be explicitly modeled in a full impact assessment. These include isopleth plots of project impacts, examination of impact patterns with respect to terrain, identification of the controlling meteorological conditions for project impacts, examination of the location of nearby sources and the background monitoring station relative to the project impact plots, wind roses, pollution roses, etc. The guidance goes on to state, " Many of the challenges ... related to cumulative assessments arise in the context of how best to combine a monitored and modeled contribution to account for background concentrations ... [to avoid] the potential for double counting of impacts from modeled sources that may be contributing to the monitored concentrations."

ADEQ's modeling guidance (ADEQ 2004) suggests that an analysis of emissions vs. distance is appropriate for screening out regional sources that are unlikely to have a significant impact in the project vicinity. The guidance describes the "20D" approach to determine whether to include a regional source in the analysis. The "20D" approach assumes a linear inverse proportional relationship between source emissions and impacts with distance. A "20D" facility-level screening approach is used to eliminate a majority of regional facilities from the NAAQS/AAAQS modeling analysis that would not be expected to have a significant impact on analysis results. Under this approach, the applicant may exclude sources that have potential allowable emissions (Q) in tons per year that are less than 20 times the distance ("20D") between the two sources in kilometers. Those sources that are not eliminated using the "20D" approach should be modeled in the full NAAQS/AAAQS analysis.

An examination of isopleths of 1-hour NO_2 impacts from the Bowie Power Station (see Appendix E) and the plot file show that maximum impacts occur to the southwest and west-northwest of the facility at a distance of 10-14 km due to impaction on higher terrain. A secondary maximum impact zone is observed close to the facility (<1 km) at or just beyond the fenceline. Maximum 1-hour NO_2 impacts decrease rapidly beyond a distance of around 13-14 km from the source.

ADEQ provided current data on Arizona sources within approximately 100 km of the Bowie Power Station, while the New Mexico Environment Department, Air Quality Bureau provided data for sources in New Mexico within 110 km of Bowie. Based on EPA and ADEQ guidance, all sources within 10 km of the Bowie Power Station site were included in the cumulative modeling and a "20D" analysis was used to screen more distant sources.

The Pistachio Corporation of Arizona facility is located 7.6 km south of Bowie, with a NO_x potential to emit (PTE) of approximately 16.9 tons per year (tpy). The facility's roaster, dryers, and silos were included in the cumulative modeling.

The only source with a Q/D score >20 is the Apache Generating Station, located 50.1 km to the southwest of Bowie. The station's three steam turbines, four gas turbines, and a startup diesel engine were included in the modeling.

Two additional sources with Q/D scores between 15 and 20 km from Bowie were included in the modeling, both compressor stations operated by El Paso Natural Gas (EPNG). The EPNG Willcox Compressor Station is located 32.4 km south-southwest of Bowie, while the EPNG Bowie Compressor Station is located 18.9 km west-southwest of Bowie. All other sources in Arizona and New Mexico had Q/D scores <10 and were not included in the modeling.

The additional sources included in the 1-hour NO_2 full analysis are shown in Appendix E. As with the Bowie Power Station, emergency generators were excluded from the 1-hour NO_2 cumulative modeling as they are unlikely to result in a significant concentration gradient in the vicinity of the Bowie project.

The cumulative 1-hour NO_2 assessment used the model (AERMOD), receptor grid, options, and meteorological data that were used for the Bowie Power Station preliminary analysis. The receptors modeled were limited to those that showed a maximum impact above the 1-hour NO_x SIL in the preliminary (Bowie Power Station only) analysis.

The AERMOD model has incorporated options to allow modeling compliance with the 1-hour NO_2 standard. Specifying "NO2" as the pollutant to be modeled invokes these options. The 98th percentile (high, 8th high) of the daily maximum 1-hour values from the Bowie project plus other nearby sources was modeled. Background NO_2 concentrations that vary by season and hour of the day were added to the combined impact within the model. The total maximum 98th percentile (high, 8th high) of the daily maximum concentrations, including background, has been compared with the 1-hour NO_2 standard.

The results indicate that the 1-hour NO_2 NAAQS would potentially be exceeded at one receptor and for up to two hours per year. The largest contributor to the potential exceedance is the Apache Generating Station.

Bowie's contribution to impacts above 90% of the NAAQS was determined using the "MAXDCONT" option in AERMOD. There were no impacts with a total concentration (including background) that exceeded 90% of the 1-hour NAAQS where Bowie's contribution was greater than 3% of the total impact; therefore, no refined grids were developed.

The maximum 1-hour NO_2 concentration predicted by the model, including background, was 192.32 $\mu g/m^3$ (the 1-hour NO_2 NAAQS is 188.7 $\mu g/m^3$). A total of two hours were predicted to exceed the NAAQS. Nearly all of the maximum impact is due to Apache Generating Station sources (88%). The largest contribution to any of the potential exceedances by the Bowie Power Station was 0.00151 $\mu g/m^3$, well below the SIL of 7.5 $\mu g/m^3$. The Bowie Power Station will not cause or contribute to any exceedance of the 1-hour NO_2 NAAQS.

5.13 Class I Area Analyses

The proposed project site is located within 100 km of four Class I areas in Arizona, the Chiricahua NM, the Chiricahua Wilderness Area (WA), the Galiuro WA, and the Saguaro National Park (NP) East Unit. The closest Class I area in New Mexico, the Gila WA, is 116 km from the project.

The Federal Land Managers' *Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* (FLAG 2010) guidance incorporates findings from recent scientific studies and methodologies for conducting visibility analyses based on experience gained through implementation of

the Regional Haze Rule. The guidance sets a threshold ratio of emissions to distance, below which AQRV review is not required for any Class I area greater than 50 km from the source.

Calculations using this guidance suggest that for any Class I area beyond around 31 km, impacts are unlikely. Consequently, AQRVs were only be analyzed at the two Class I areas located less than 50 km from the Bowie Power Station, Chiricahua NM (38 km) and Chiricahua WA (47 km). PSD Class I increment consumption was also assessed at Chiricahua NM and Chiricahua WA.

The Fort Bowie National Historic Site is located approximately 23 km to the south-southeast of the proposed project location. Although the historic site is not a Class I area, the National Park Service (NPS) has previously asked that visibility impacts be assessed there.

5.13.1 Class I Modeling Analyses Design

For NO_2, PM_{10}, and $PM_{2.5}$, impacts from the project were estimated within Chiricahua NM and Chiricahua WA for comparison with Class I significance levels (there are no CO increments or AQRVs, and SO_2 emissions from the Bowie Power Station are below PSD significant emission rates). Project impacts on visibility and acid deposition were also assessed at these locations. Impacts on applicable AQRVs, deposition, and increments were calculated at NPS-provided Class I area receptor locations, converted to the appropriate grid locations.

An analysis of the proposed source's effect on Class I increments and AQRVs in the Chiricahua WA was made using the most recent EPA-approved version of the long-range transport model CALPUFF (version 5.8). The nearest boundary of the Chiricahua WA is approximately 47 km from the project site, while the farthest edge is approximately 77 km. CALPUFF was applied for the Bowie project to estimate impacts at the Chiricahua WA, including for receptors within 50 km of the Bowie project site.

Given that Chiricahua NM lies completely within 50 km of the project site, however, only AERMOD was used to predict impacts for comparison with the NO_2, PM_{10}, and $PM_{2.5}$ Class I significance levels at this Class I area. Deposition impacts at this Class I area were assessed with CALPUFF because AERMOD lacks the required chemical processing capabilities for this type of impact analysis.

5.13.2 Class I Increment Analysis

Maximum impacts predicted in each Class I area for each pollutant and averaging period are shown in Table 5-7. All impacts are below the significance levels.

Table 5-7. Results of Class I Significant Impact Analysis

Averaging Period/ Pollutant	Maximum Predicted Impact Chiricahua NM[a] ($\mu g/m^3$)	Maximum Predicted Impact Chiricahua WA[b] ($\mu g/m^3$)	Class I Modeling Significance Level ($\mu g/m^3$)
Annual NO_2	0.002	0.010	0.1
24-hour PM_{10}	0.013	0.059	0.3
Annual PM_{10}	0.001	0.006	0.2
24-hour $PM_{2.5}$	0.012	0.059	0.07[c]
Annual $PM_{2.5}$	0.001	0.006	0.06[c]

[a] Maximum impacts for 1-year of site-specific meteorological data determined with AERMOD
[b] Maximum impacts from 2001-2003 as determined with CALPUFF/CALPOST

Notes:

$\mu g/m^3$	=	Micrograms per cubic meter	NO_2	=	Nitrogen dioxide
PM_{10}	=	Particulate matter < 10 micrometers	$PM_{2.5}$	=	Particulate matter < 2.5 micrometer
NM	=	National Monument	WA	=	Wilderness Area

5.13.3 Class I Deposition Analysis

The CALPUFF model was used to estimate nitrogen deposition within the respective Class I areas. The results of this analysis are shown in Table 5-8.

Table 5-8. Deposition Impacts

Deposition	2001 (kg/ha/yr)	2002 (kg/ha/yr)	2003 (kg/ha/yr)	Deposition Analysis Threshold
Chiricahua Wilderness Area				
Total Nitrogen	0.001	0.002	0.002	0.005
Chiricahua National Monument				
Total Nitrogen	0.001	0.003	0.002	0.005

Notes:
kg/ha/yr = Kilogram per hectare per year

5.13.4 Class I Visibility Analysis

For assessing regional haze impacts at the Chiricahua WA, emission rates of criteria pollutants were apportioned in accordance with NPS guidance for applicable sources such as the combustion turbines to account for varying particulate matter speciation and associated extinction coefficients and emission rates. The specific NPS guidance for natural gas-fired combustion turbines was used in CALPUFF to account for varying emitted particle sizes and the potential effects on light scattering and visibility. For those sources without such speciation guidance, standard emission rates were used.

The visibility assessment employed the MVISBK 8, sub-mode 5 approach, which uses Class I-specific values of annual natural background concentrations, monthly f(RH) values for hygroscopic species, and Rayleigh conditions. Appropriate values for each specific Class I area were obtained from the 2010 FLAG (FLAG 2010) guidance. The 98th percentile change in light extinction was compared to the annual average natural condition value for each Class I area to determine whether the 5% visibility threshold for concern will be exceeded.

For the Chiricahua WA, impacts (change in light extinction) for 2001-2003 are all below 5%.

The EPA VISCREEN model was used to assess the likelihood of visibility impairment due to the planned Bowie Power Station within 50 km of the facility. The model is a simple screening technique used to estimate the mass of pollutant in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients and these values are compared to screening threshold levels to determine the potential magnitude and type of visibility impairment.

The VISCREEN analyses focused on potential coherent plume impacts in relatively nearby areas (within 50 km), rather than uniform haze impacts in distant areas. Coherent plume impacts occur when a visible plume or colored layer is visible against the sky or distant terrain features. Coherent plume impacts may occur in areas that are close to a source of pollutants, while uniform haze may occur further downwind.

VISCREEN reports two tests: one for plumes located inside the area of interest and one for plumes located outside the boundaries of the area of interest. The latter is only appropriate for Class I areas where “integral vistas” of objects outside the area are of concern, while the former is appropriate for all Class I areas.

A Level I screening analysis was performed for two locations, the Chiricahua NM Class I area and the Fort Bowie National Historic Site. Although Fort Bowie National Historic Site is not a Class I area, the NPS has previously asked that visibility impacts be assessed there. The nearest edge of this historic site is located approximately 23 km to the south-southeast of the proposed project location.

The results of the Level I assessment at each location suggested that some of the screening thresholds may be exceeded under the conservative assumptions inherent in Level I screening. Because of this, a Level II analysis was completed, again using VISCREEN.

Using the Level II approach, the visual screening criteria are not exceeded in the Chiricahua NM Class I area. Impacts at the Fort Bowie National Historical Site are also presented in Appendix E. Visibility effects thresholds have not been established for Class II areas and the Level I and II procedures automatically compare the impacts against Class I thresholds. Note that the Class I screening values are not necessarily appropriate for Class II areas such as Fort Bowie.

5.14 Additional Impact Analyses

The PSD regulations codified at 40 CFR 52.21(o) require the applicant to conduct an analysis of the impact that would occur to soils and vegetation of significant commercial or recreational value as a result of the project. As stated in 40 CFR 52.21(o), the applicant is not required to analyze the impact on vegetation that has no significant commercial or recreational value. The applicant is also required to analyze general commercial, residential, industrial, and other growth associated with the project.

5.14.1 Growth Analysis

The purpose of the growth analysis is to project the industrial, commercial, and residential growth, and related emissions, that are anticipated to occur in the area due to the construction of the new proposed project. The emissions associated with such projected growth are those not directly related to the new source or modification.

Construction of the project is expected to result in approximately 25 new, permanent employment opportunities for plant operations. It is anticipated that the personnel hired and involved in the construction phase of the project would be drawn, in large part, from the surrounding communities, as would some of the operations personnel. As such, no significant increase in air pollutant emissions indirectly associated with the proposed project is expected to occur.

5.14.2 Soils and Vegetation Analysis

An examination of the Bowie natural gas-fired combined-cycle plant's potential impact to sensitive soils or vegetation in the project vicinity has been prepared. The intent of this requirement is to address the potential impact of the proposed project's emissions on sensitive soils and vegetation of commercial or recreational value that occur in the project's impact area.

EPA provides criteria for evaluating impacts on soils and vegetation in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (Screening Procedure; EPA 450/2-81-078). In addition, the 1990 *Draft New Source Review Workshop Manual* (NSR Manual) also states that "For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary [NAAQS] will not result in harmful effects." NAAQS secondary standards are intended to protect public welfare, including the consideration of economic interests, vegetation, and visibility. While ambient concentrations of criteria pollutants below the secondary NAAQS are expected to be protective of most soil types and vegetation, this may not be true for particularly sensitive soils or plant species (EPA 1998).

The potential impacts of the proposed project were compared to relevant thresholds, including but not limited to secondary NAAQS, to determine effects to vegetation. Based on a comparison of maximum projected pollutant concentrations with reported minimum exposure levels at which visible damage to or growth retardation of plants may occur, the project's impacts are unlikely to adversely affect crops grown in the area (see Appendix E for details).

Air pollutants may also impact the stability of soil systems including increased soil temperature, moisture stress, and runoff and erosion due to damaged vegetative cover. Soils in the vicinity of the Bowie project have pH levels that indicate they are not overly sensitive to acidic pollutant concentrations or deposition. Pollutant concentrations from the Bowie project are well below the secondary NAAQS, indicating that adverse impacts to most soils are unlikely.

The EPA has concluded that there is no comprehensive understanding of particulate matter deposition effects on crops. The phytotoxic response due to a given mass concentration of airborne particulate matter differs widely depending on the composition. Currently, there is no evidence to demonstrate that the exposure of foliage to ambient concentrations of particulate matter elicits more than a minimal response.

The possible effects of deposition of trace metals to soils and subsequent uptake by plants was also screened using procedures outlined in the Screening Procedure document. Only a few of the trace metals addressed in the screening procedure will be emitted by the project, primarily from the turbines and duct burners. The screening results indicate that the Bowie Power Station will not have adverse impacts due to trace metals.

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NRO-000-00

COMMONWEALTH of VIRGINIA

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Secretary of Natural Resources

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Director

Thomas A. Faha
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
NON-ATTAINMENT NEW SOURCE REVIEW PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Green Energy Partners / Stonewall, LLC
P.O. Box 660
Hamilton, Virginia 20158
Registration Number: 73826
Plant ID No. 51-107-01019

is authorized to construct and operate:

DRAFT 02-27-2013

An electric power generation facility

located at:

20077 Gant Lane
Leesburg, VA 20175 (Loudoun County)
(approximately 4 miles south/south east of
Leesburg & north of Dulles Toll Road (SR 267)
39.058° N Latitude, 77.545° W Longitude

in accordance with the conditions of this permit

Approved on: DATE

Regional Director

Permit consists of 37 pages
Permit Conditions 1 to 83.
Source Testing Report Format

INTRODUCTION

This permit approval is based on the permit application dated July 19, 2012, with additional information submitted on August 16, 2012, and the modeling analysis and revised application which were both submitted on October 5, 2012, and November 15, 2012. Any changes in the permit application specifications, or any existing facilities which alter the impact of the facility on air quality, may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-80-1110, 9 VAC 5-80-2010, and 9 VAC 5-10-20 of the Commonwealth of Virginia State Air Pollution Control Board's (Board's) Regulations (Regulations) for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the Department of Environmental Quality (DEQ) or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the Board's Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

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PROCESS REQUIREMENTS

1. **Equipment List**

   Equipment to be constructed at this facility consists of:

   -Two (2) combined-cycle electric power generating units (Ref. No. CCT1 & CCT2) where each unit includes the following emission units:

   - One (1) General Electric natural gas-fired combustion turbine (CT) generator, Model GE 7FA.05, rated at 2,230 million Btu per hour heat input (Ref. No. CT1 & CT2) with inlet evaporative coolers (NSPS Subpart KKKK) and,

   - One (1) 650 million Btu per hour duct fired (Ref. No. DB1 & DB2) heat recovery steam generator (HRSG) that provides steam to a common steam turbine generator (NSPS Subpart KKKK).

   OR

   - One (1) Siemens natural gas-fired combustion turbine (CT) generator, Model SGT6-5000F5, rated at 2,260 million Btu per hour heat input (Ref. No. CT1 & CT2) with inlet evaporative coolers (NSPS Subpart KKKK) and,

- One (1) 450 million Btu per hour duct fired (Ref. No. DB1 & DB2) heat recovery steam generator (HRSG) that provides steam to a common steam turbine generator (NSPS Subpart KKKK).

-One (1) natural gas-fired auxiliary boiler rated at 75 million Btu per hour heat input (Ref. No. AB1) (NSPS Subpart Dc).

-One (1) natural gas-fired fuel gas heater, rated at 20 million Btu per hour heat input (Ref. No. FGH1) (NSPS Subpart Dc).

-One (1) diesel-fired emergency generator, rated at 15.4 million Btu per hour heat input and 1,500 kW electric power output (Ref. No. EG1) (NSPS Subpart IIII and MACT Subpart ZZZZ).

-One (1) diesel-fired emergency fire pump, rated at 2.54 million Btu per hour heat input and 330 BHP mechanical power output (Ref. No. EFP1) (NSPS Subpart IIII and MACT Subpart ZZZZ).

-One (1) ten cell mechanical draft cooling tower rated at 187,400 gallons/minute of cooling water (Ref. No. MCT1- MCT10).

-One (1) 12,000-gallon aqueous ammonia above ground storage tank (Ref. No. AST1).

-One (1) 1,250-gallon diesel above ground storage tank for the emergency generator (Ref. No. AST2).

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-One (1) 400-gallon diesel above ground storage tank for the fire pump (Ref. No. AST3).

-Circuit Breakers containing sulfur hexafluoride (SF_6) (Ref. No. CB1)

Specifications included in the permit under this condition are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9 VAC 5-80-1180 D 3, 9 VAC 5-80-2050, and 9 VAC 5-80-1605 A)

PROCESS REQUIREMENTS

2. **Emission Controls: Combustion Turbines (Ref. No. CT1 & CT2) and Heat Recovery Steam Generators (HRSG) Duct Burners (DB1 & DB2)**

   a. NO_X
   Oxides of nitrogen (NO_X) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by dry low-NO_X combustion with selective catalytic reduction (SCR) control system with ammonia injection. The SCR system shall be provided with adequate access for inspection and shall be in operation when the combustion turbines and duct burners are operating, at all times except during start up and shutdown, as defined in Condition 15.

   b. CO and VOC
   Carbon monoxide (CO) and volatile organic compounds (VOC) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator

(HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by an oxidation catalyst and combustion practices as recommended by the equipment manufacturer. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbines and duct burners are operating, at all times except during start up and shutdown, as defined in Condition 15.

c. PM-10 and PM-2.5
Particulate matter (PM-10 and PM-2.5) emissions from each combustion turbine (Ref. No. CT1 & CT2) and each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by combustion practices as recommended by the equipment manufacturer, and use of pipeline natural gas, as defined in 40 CFR §72.2.

d. Greenhouse Gases
Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO_2e from the combined cycle gas turbine generators (CT1 & CT2) for both the GE 7FA.05 and Siemens SGT6-5000F5 and associated heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall be controlled by combustion practices as recommended by the equipment manufacturer, and use of pipeline natural gas, as defined in 40 CFR § 72.2. The combined cycle gas turbine generators and associated HRSG DBs shall operate at a Higher Heating Value (HHV) heat rate, at full load and corrected to ISO conditions, not to exceed 7,340 Btu HHV/kWh gross output without duct burning and 7,780 Btu HHV/kWh gross output with duct burning. Compliance with this limit shall be demonstrated as contained in Conditions 63 and 68.

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(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

3. **Emission Controls: Auxiliary Boiler (Ref. No. AB1) and Fuel Gas Heater (Ref. No. FGH1)**

a. NO_X
Oxides of nitrogen (NO_X) emissions from the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be controlled by ultra low-NO_X burners with a NOx performance of 9 ppmvd at 3% O_2 for natural gas. The low NOx burners shall be installed and operated in accordance with manufacturer's specifications.

b. CO and VOC
Carbon monoxide (CO) and volatile organic compounds (VOC) emissions from the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be controlled by good combustion practices, operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 50 ppmvd at 3% O_2. Boiler and heater operators shall be trained in the proper operation of all such equipment. (Refer to Condition 75 for training and record keeping requirements).

c. Particulate Matter (PM-10 and PM-2.5)
PM-10 and PM-2.5 emissions from the auxiliary boiler (AB1) and the fuel gas heater (FGH1) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a sulfur content of no greater than 0.1 grains per 100 standard cubic

feet (scf), on a 12-month rolling average.

d. Greenhouse Gases
CO_2e from the auxiliary boiler (AB1) and the fuel gas heater (FGH1) shall be controlled by the use of pipeline-quality natural gas and high efficiency design and operation.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-80-1705 B and 9 VAC 5-80-2050)

4. **Emission Controls: Emergency Generator (Ref. No. EG1)**
Oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM-10 and PM-2.5) emissions from the emergency generator (Ref. No. EG1) shall be controlled by combustion practices as recommended by the equipment manufacturer and the use of ultra low sulfur diesel fuel oil with a maximum sulfur content of 15 ppm by weight. CO_2e emissions shall be controlled by the use of low carbon fuel and high efficiency design and operation.
(9 VAC 5-80-1180, 9 VAC 5-80-1705 B and 9 VAC 5-50-260)

5. **Emission Controls: Emergency Fire Pump (Ref. No. EFP1)**
Oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM-10 and PM-2.5) emissions from the emergency fire pump (Ref. No. EFP1) shall be controlled by combustion practices as recommended by the equipment manufacturer and the use of ultra low sulfur diesel fuel oil with a maximum sulfur content of 15 ppm by weight. CO_2e emissions shall be controlled by the use of low carbon fuel and high efficiency design and operation.
(9 VAC 5-80-1180, 9 VAC 5-80-1705 B, 9 VAC 5-80-2050, and 9 VAC 5-50-260)

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6. **Monitoring Devices: SCR –** Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with the device manufacturer's written requirements and recommendations. Each monitoring device shall be provided with adequate access for inspection, and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

7. **Monitoring Devices: Oxidation Catalyst –** Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with the device manufacturer's written requirements and recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 9 VAC 5-80-1705 B)

8. **Monitoring Device Observation and Documentation: SCR –** The devices used to continuously measure ammonia feed rate and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system, but not less than once per day of operation.
(9 VAC 5-50-50 H)

9. **Monitoring Device Observation and Documentation: Oxidation Catalyst -** The devices used to continuously measure the catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst, but not less than once per day of operation. (9 VAC 5-50-50 H)

10. **Monitoring Device: Hour Meter -** The emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP-1) shall be equipped with a non-resettable hour metering device to monitor the operating hours of each unit. Each monitoring device shall be observed by the permittee with a frequency of not less than once each day that the generator/fire pump is in operation. The permittee shall keep a log of these observations.

    Each monitoring device shall be installed, maintained, calibrated (as appropriate) and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the generator/fire pump is operating.
    (9 VAC 5-80-1180 D and 40 CFR 60.4209)

OPERATIONAL LIMITATIONS

11. **Fuel: Natural Gas Fired Units –** The approved fuel for each combustion turbine (Ref. No. CT1 & CT2), each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2), the auxiliary boiler (Ref. No. AB1), and the fuel gas heater (Ref. No. FGH1) is pipeline natural gas as defined in 40 CFR § 72.2, with a maximum sulfur content of 0.1 grains or less of total sulfur per 100 standard cubic feet. A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR § 72.2. No change in fuel type may occur without DEQ approval. A change in the fuel may require a permit to modify and operate.
    (9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, 9 VAC 5-80-2050, and 40 CFR 60.4330(a)(2))

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12. **Fuel Specification: Diesel Fired Units** - The approved fuel for the emergency engine generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) shall be diesel fuel that meets the specifications below:

    a. Does not exceed the American Society for Testing and Materials (ASTM) specifications, D975, for grade ultra low sulfur 2-D, or grade 2-D S14, or

    b. Has a maximum sulfur content not to exceed 0.0015% by weight (15 ppm), and either a minimum cetane number of forty or maximum aromatic content of thirty-five percent by volume.

    (9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-50-260)

13. **Fuel Certification -** The permittee must use the sources listed in Condition 13.a to demonstrate compliance with Condition 11 and the sources of information in Condition 13.b to demonstrate compliance with Condition 12:

a. The fuel characteristic in a current, valid purchase contract, tariff sheet or transportation contract for the natural gas, specifying that the maximum total sulfur content for the natural gas is 0.1 grains of sulfur or less per 100 standard cubic feet and / or representative fuel sampling data, which shows that the sulfur content of the fuels does not exceed 2.61 x 10^{-4} lb SO_2/MMBtu heat input.

   If the permittee elects not to demonstrate the sulfur content using the above option, the permittee may:

   i. Determine and record the total sulfur content of the natural gas once per unit operating day; or,

   ii. Develop custom schedules for determination of the total sulfur content of the natural gas, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CRF 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

b. The permittee shall obtain a fuel certification from the fuel supplier with each shipment of diesel fuel oil. Each fuel supplier certificate shall contain the following:

   i. The name of the fuel supplier, and
   ii. The date on which the diesel fuel oil was received, and
   iii. The quantity of diesel fuel oil delivered in the shipment, and

   iv. Either a statement that the diesel fuel oil conforms to the requirements of Condition 12 – Fuel Specification, or
   v. Alternately, the permittee shall obtain approval from the Regional Air Compliance Manager of the DEQ's Northern Regional Office (NRO) at the address listed in Condition 57 if other documentation will be used to certify the diesel fuel oil type.

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Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by the DEQ, may be used to determine compliance with the fuel specifications stipulated in Condition 12. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-80-1180, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 170-160, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

14. **Fuel Throughput –** The two GE 7FA.05 combustion turbines (Ref. No. CT1 & CT2) and two 650 MMBtu/hr duct burners (Ref. No. DB1 & DB2) shall not consume more than 4.01 x 10^{10} cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. The two Siemens SGT6-5000F5 combustion turbines (Ref. No. CT1 & CT2) and two 450 MMBtu/hr duct burners (Ref. No. DB1 & DB2) shall not consume more than 4.00 x 10^{10} cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-2050)

15. **Startup / Shutdown –** The short-term emission limits contained in Condition 33 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as the average time per turbine for the two turbine plant to complete startup and shutdown as follows:

   i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emission limits for cold startup periods shall not exceed 226 minutes per occurrence.

   ii. Warm Startup – refers to restarts made more than 4, but less than 72 hours after shutdown. Exclusion from the short-term emission limits for warm startup periods shall not exceed 128 minutes per occurrence.

   iii. Hot Startup – refers to restarts made 4 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 38 minutes per occurrence.

   iv. Shutdown – refers to the period between the time the turbine load drops below 50 percent operating level and the fuel supply to the turbines is cut. Exclusion from the short-term emissions limits for shut down shall not exceed 0.23 hours per occurrence.

b. The permittee shall operate the Continuous Emission Monitoring Systems (CEMS) during the periods of startup and shutdown.

c. The permittee shall record the date, time, and duration of each startup and shutdown period. The records must include calculations of NOx and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

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d. During startup, the combustion turbine SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of unit output.

(9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180, and Table 1 to NSPS KKKK of part 60)

16. **Operational Limit – Duct Burners**
The duct burners (Ref. No. DB1 & DB2) shall not operate independently of each combustion turbine (Ref. No. CT1 & CT2).
(9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-40-410, and 40 CFR 60.4320)

17. **Operational Limit – Duct Burners**
Each heat recovery steam generator (HRSG) duct burner (Ref. No. DB1 & DB2) shall not operate more than 1,400 hours per year, calculated monthly as the sum of each consecutive twelve month period.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

18. **Requirements by Reference** – Except where this permit is more restrictive than the applicable requirement, the combustion turbines (Ref. No. CT1 & CT2) and the heat recovery steam generator (HRSG) shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.

(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 40 CFR 60, Subpart KKKK)

19. **CAIR (Clean Air Interstate Rule) NO_X Annual Trading Requirements –**The combined-cycle power generating units (Ref. No. CCT1 & CCT2) listed in Condition 1 meet the definition of a CAIR NO_X Unit and are subject to the CAIR NO_X emission limits under 9 VAC 5-140-1040 or for opt in sources under 9 VAC 5-140-1800. As required by 9 VAC 5-140-1200 A, for each CAIR NO_X source required to have a federally enforceable permit, such permit will include the CAIR permit to be administered by the permitting authority. The following requirements pertain to the CAIR NO_X Annual Trading program:

    a. Prior to operation commencement, the permittee shall obtain a CAIR permit, as required by 9 VAC 5-140-1200 A, to be administered by the Virginia Department of Environmental Quality (DEQ) under the authority of 9 VAC 5-80-360 *et seq*., and 9 VAC 5-140-1010 *et seq*.

    b. As commencement of operation of the permitted facility (the first day a combustion turbine burns fuel), the permittee shall comply with the requirements of the CAIR NO_X emission limitations under 9 VAC 5-140-1040.

    c. Each combined-cycle power generating unit (combustion turbine and heat recovery steam generator) in Condition 1 meets the applicability requirements as provided in 9 VAC 5-140-1040 A.1 and A.2. The permittee shall meet the monitoring, emission calculation, recordkeeping, reporting, and testing requirements as applicable under 9 VAC 5 Chapter 140, Part II, Article 8.

    (9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5 Chapter 140, Part II, Article 8)

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20. **Fuel Throughput – Auxiliary Boiler (AB1)**
    The auxiliary boiler (Ref. No. AB1) shall not consume more than 6.44×10^8 cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
    (9 VAC 5-80-1180 and 9 VAC 5-80-2050)

21. **Fuel Throughput – Fuel Gas Heater (Ref. No. FGH1)**
    The fuel gas heater (Ref. No. FGH1) shall not consume more than 1.72×10^8 cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
    (9 VAC 5-80-1180 and 9 VAC 5-80-2050)

22. **Requirements by Reference –** Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
    (9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 40 CFR 60, Subpart Dc)

23. **Emergency Generator and Emergency Fire Pump Operation –** The operation of the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) are limited to emergency situations. Emergency situations include emergency generator use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted and emergency engine use to pump water in case of fire or flood, etc. The emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year for each unit.
(9 VAC 5-80-1180, 40 CFR 60.4211(e), and 40 CFR 60.4219)

24. **Operating Hours: Emergency Generator –** The emergency generator (Ref. No. EG1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-2050)

25. **Operating Hours: Emergency Fire Pump –** The emergency fire pump (Ref. No. EFP1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

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26. **Maintenance and Operation –** The permittee must maintain and operate the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) in accordance with the device manufacturer's written requirements. In addition, the permittee may only change those settings that are allowed by the device manufacturer's written requirements.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.4206, and 40 CFR 60.4211)

27. **Emission Controls: Cooling Tower –** Particulate matter emissions from the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) shall be controlled to a drift rate of 0.0005 percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 5,000 ppm total dissolved solids.
(9 VAC 5-80-1705 B, 9 VAC 5-50-280 and 9 VAC 5 -80-2050)

28. **Sampling & Monitoring – Ten Cell Mechanical Draft Cooling Tower (Ref. No. MCT1-MCT10)**
The facility shall sample the water used by the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) for total dissolved solids (TDS) at a frequency of not less than once per month to ensure compliance with the TDS in Condition 27. If the TDS sampling demonstrates compliance for three years of cooling tower operation, then the permittee can request a reduction in the sampling frequency. Samples taken as required by this permit shall be analyzed in accordance with 1 VAC 30-45, Certification for Noncommercial Laboratories, or 1 VAC 30-46, Accreditation for Commercial Environmental Laboratories.
(9 VAC 5-50-260, 9 VAC 5-170-160, 9 VAC 5-80- 2050, and 9 VAC 5-80-2080)

29. **Emission Controls: Electrical Breakers –** Greenhouse gas emissions (including SF_6) from the electrical circuit breakers (Ref No. CB1) shall be controlled by an enclosed circuit breaker, with a maximum annual leakage rate of 1.0 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use. Emissions shall be monitored in accordance with the requirements of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use (40 CFR Part 98, Subpart DD).
(9 VAC 5-80-1705 B, 9 VAC 5-50-280)

30. **Re-tuning –** Excess emissions resulting from the retuning of the combustion turbines (Ref. No. CT1 & CT2) shall be permitted provided that:

    a. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbine (Ref. No. CT1 & CT2) re-tuning event in any 24 hour period. The operator may request additional hours from the DEQ as long as the notification is done as soon as the source is aware that the re-tuning event will exceed twelve hours.

    b. During each combustion turbine (Ref. No. CT1 & CT2) retuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

    c. The permittee shall notify the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57 no less than 24 hours prior to each turbine's retuning event. The notification shall include, but is not limited to:

        i. Identification of the specific turbine to be retuned.
        ii. Reason for the retuning event.
        iii. Measures to be taken to minimize the length of the retuning event.

    d. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQ's NRO of all the pertinent facts concerning the retuning event, as soon as practicable, but not later than 14 business days after the retuning event. The notification shall include, but is not limited to:

        i. Identification of the turbine that was retuned.
        ii. The magnitude of excess emissions per turbine, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions.

    e. NO_X emissions during each turbine's retuning shall be recorded and included in the associated quarterly reports and the total annual emissions as required in Condition 33.

    f. The retuning event for each turbine shall be identified on the Data Acquisition Report.

    (9 VAC 5-20-180, 9 VAC 5-50-50, and 9 VAC 5-50-410)

31. **Pollution Prevention: Ammonia –** Compliance with the ammonia emission limit in Condition 33 shall be determined based on a one-hour block average. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the

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ammonia emissions and demonstrating compliance with the ammonia emission limit from each SCR system to the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia emission limit at least 95 percent of the time that the SCR is operating. Compliance with the 95 percent time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior thirty days, compliance with the 95 percent limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 170-160, and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

32. **Pollution Prevention: SCR Replacement –** At least two years prior to a planned replacement of the entire SCR system, the permittee shall conduct a study of technically and economically feasible and commercially available NO_X control devices. The study shall include the cost effectiveness for each control device evaluated, including SCR. The results of the evaluation shall be submitted to the Regional Air Permitting Manager of the DEQ's NRO at the address listed in Condition 57 prior to ordering the new system. In the event the permittee wants to replace the SCR with an alternative control device, such a replacement may not require a permit to modify and operate, providing the new system provides an equal or better level of control.
(9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-170-160, and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

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EMISSION LIMITS

33. **Emission Limits - Combined-Cycle Power Generation Units (Ref. No. CCT1 & CCT2)**

Short-Term Emission Limits - Emissions from the operation of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) shall not exceed the limits specified below:

GE 7FA.05

Air Pollutant	Short-Term Emission Limits
Oxides of Nitrogen (as NO_2)	▪ 2.0 ppmvd at 15% O_2 W & w/o DB firing ▪ 21.0 lb/hr with HRSG duct burner firing ▪ 16.2 lb/hr without HRSG duct burner firing
Carbon Monoxide (CO)	▪ 2.0 ppmvd at 15% O_2 with & w/o duct burning. ▪ 12.7 lb/hr with HRSG duct burner firing ▪ 9.9 lb/hr without HRSG duct burner firing
Volatile Organic Compounds (VOCs) (as methane)	▪ 2.4 ppmwv at 15% O_2 with duct burner firing ▪ 1.0 ppmwv at 15% O_2 without duct burner firing ▪ 7.3 lb/hr with HRSG duct burner firing ▪ 2.8 lb/hr without HRSG duct burner firing
PM-10 (Includes filterable and condensibles)	▪ 3.34×10^{-3} lb/MMBtu at full load ▪ 16.2 lb/hr with HRSG duct burner firing ▪ 9.6 lb/hr without HRSG duct burner firing
PM-2.5 (Includes filterable and condensibles)	▪ 3.34×10^{-3} lb/MMBtu at full load ▪ 16.2 lb/hr with HRSG duct burner firing ▪ 9.6 lb/hr without HRSG duct burner firing
Sulfur Dioxide (SO_2)	▪ 2.61×10^{-4} lb/MMBtu

	▪ 0.75 lb/hr with HRSG duct burner firing ▪ 0.58 lb/hr without HRSG duct burner firing
Ammonia (NH_3)	▪ 5.0 ppmvd at 15% O_2

Siemens SGT6-5000F5

Air Pollutant	Short-Term Emission Limits
Oxides of Nitrogen (as NO_2)	▪ 2.0 ppmvd at 15% O_2 ▪ 20.4 lb/hr with HRSG duct burner firing ▪ 17.1 lb/hr without HRSG duct burner firing
Carbon Monoxide (CO)	▪ 2.0 ppmvd at 15% O_2 with & w/o duct burning. ▪ 12.5 lb/hr with HRSG duct burner firing ▪ 10.4 lb/hr without HRSG duct burner firing
Volatile Organic Compounds (VOCs) (as methane)	▪ 1.5 ppmwv at 15% O_2 with duct burner firing ▪ 1.0 ppmwv at 15% O_2 without duct burner firing ▪ 5.7 lb/hr with HRSG duct burner firing ▪ 3.0 lb/hr without HRSG duct burner firing
PM-10 (Includes filterable and condensables)	▪ 3.74×10^{-3} lb/MMBtu at full load ▪ 14.5 lb/hr with HRSG duct burner firing ▪ 10.1 lb/hr without HRSG duct burner firing
PM-2.5 (Includes filterable and condensables)	▪ 3.74×10^{-3} lb/MMBtu at full load ▪ 14.5 lb/hr with HRSG duct burner firing ▪ 10.1 lb/hr without HRSG duct burner firing
Sulfur Dioxide (SO_2)	▪ 2.61×10^{-4} lb/MMBtu ▪ 0.70 lb/hr with HRSG duct burner firing ▪ 0.58 lb/hr without HRSG duct burner firing
Ammonia (NH_3)	▪ 5.0 ppmvd at 15% O_2

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Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

ppmwv = parts per million by volume on a wet gas basis, corrected to 15 percent O_2.

Short-term emission limits for VOC and PM-10 represent averages for a three-hour sampling period. Short-term emission limits for nitrogen oxides and carbon monoxide shall be calculated as one-hour averages.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 15 of this permit.

Compliance with the SO_2 limit may be determined as stated in Condition 11.

This permit may be changed in accordance with 9 VAC 5-80-1925 and 9 VAC 5-80-2000, to reduce the emission limits based on results from stack testing as required in Conditions 56, 58 and 59 of this permit.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 5-80-1705, 40 CFR 60.4320, 40 CFR 60.4330 and the Virginia Pollution Prevention Act Subsection 10.1-1425.11)

34. **<u>Emission Limits: Combined-Cycle Power Generating Units (Ref. No. CCT1 & CCT2) -</u>** CO_2e emissions from the combined cycle gas turbine generators and associated HRSGs shall not exceed 903 lb/MWh (gross) calculated monthly on a 12-operating month annual average basis. Compliance shall be determined each month by summing the CO_2e emissions for all hours in which power is being generated to the grid during the previous 12 months and dividing that value by the sum of the gross electrical energy output over that same period.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

35. **Annual Process Emission Limits** – Total emissions from the combined operation of the two combined-cycle power generating units (Ref. No. CCT1 & CCT2), including duct burners, shall not exceed the limits specified below:

GE 7FA.05

Pollutant	Annual Emissions (tons per year)
Oxides of Nitrogen (as NO_2)	148.6
Carbon Monoxide (CO)	188.8
Volatile Organic Compounds (VOC)	31.0
PM-10 (Includes filterable and condensables)	93.7
PM-2.5 (Includes filterable and condensables)	93.7
Sulfur Dioxide (SO_2)	5.3
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,418,273

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Or:

Siemens SGT6-5000F5

Air Pollutant	Annual Emissions (tons per year)
Oxides of Nitrogen (as NO_2)	154.45
Carbon Monoxide (CO)	124.8
Volatile Organic Compounds (VOC)	45.26
PM-10 (Includes filterable and condensables)	94.68
PM-2.5 (Includes filterable and condensables)	94.68
Sulfur Dioxide (SO_2)	5.26
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,414,296

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits.

Compliance with these limits may be determined as stated in Conditions 11, 14, 17, 47, and 71. Annual emissions shall be calculated as the sum of each consecutive 12-month period.

This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Conditions 56, 58 and 59 of this permit.

(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-2050, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

36. **Visible Emission Limit –** Visible emissions from each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (Reference 40 CFR 60, Appendix A). This condition applies at all times except during start up, shutdown (as defined in Condition 15), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260, and 9 VAC 5-80-1705)

37. **Process Emission Limits – Auxiliary Boiler (Ref. No. AB1)**
Emissions from the auxiliary boiler (Ref. No. AB1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	0.83	3.61
Carbon Monoxide (CO)	2.78	12.15
Volatile Organic Compounds (VOC)	0.15	0.66
PM-10 (Includes filterable and condensibles)	0.15	0.66
PM-2.5 (Includes filterable and condensibles)	0.15	0.66
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	8,873	38,856

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These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

38. **Process Emission Limits – Fuel Gas Heater (Ref. No. FGH1)**
Emissions from the fuel gas heater (Ref. No. FGH1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	0.22	0.96
Carbon Monoxide (CO)	0.74	3.24
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,365	10,362

These emissions are derived from the estimated overall emission contribution from the operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

39. **Visible Emission Limit –** Visible emissions from both the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) stacks shall not exceed 10 percent opacity as determined by EPA Method 9 (Reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

40. **Process Emission Limits – Emergency Generator (Ref. No. EG1)**
Emissions from the emergency generator (Ref. No. EG1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	21.16	5.29
Carbon Monoxide (CO)	11.57	2.89
Volatile Organic Compounds (VOC)	21.16	5.29
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,534	634

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These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 24.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80- 1785 and 9 VAC 5-80-2050)

41. **Process Emission Limits – Emergency Fire Pump (Ref. No. EFP1)**
Emissions from the emergency fire pump (Ref. No. EFP1) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
Oxides of Nitrogen (as NO_2)	2.17	0.54
Carbon Monoxide (CO)	1.90	0.47
Volatile Organic Compounds (VOC)	2.17	0.54
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	416	104

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 25.
(9 VAC 5-50-260, 9 VAC 5-80-1773 and 9 VAC 5-80-2050)

42. **Process Emission Limits – Ten Cell Mechanical Draft Cooling Tower (Ref. No. MCT1 - MCT10)**

Emissions from the ten cell mechanical draft cooling tower (Ref. No. MCT1 – MCT10) shall not exceed the limits specified below:

Pollutant	lb/hr	tons/year
PM-10 (Includes filterable and condensibles)	2.35	10.27
PM-2.5 (includes filterable and condensibles)	0.73	3.19

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 27 and 28.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

43. **Process Emission Limits – Total Annual Facility-Wide Emission Limits**
Emissions from the facility shall not exceed the limits specified below:

Pollutant	GE 7FA.05 tons/year	Siemens SGT6-5000F5 tons/year
Oxides of Nitrogen (as NO_2)	159.0	164.9
Carbon Monoxide (CO)	205.6	143.6
Volatile Organic Compounds (VOC)	37.6	51.9
PM-10 (includes filterable and condensibles)	105.2	106.1
PM-2.5 (includes filterable and condensibles	98.1	99.1
Sulfur Dioxide (SO_2)	5.44	5.37
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO_2e)	2,468,468	2,464,490

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These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits in Conditions 35 (Ref. No. CCT1 & CCT2),37 (Ref. No. AB1), 38 (Ref. No FGH1), 40 (Ref. No. EG1), 41 (Ref. No. EFP1), and 42 (Ref. No. MCT1-MCT10).
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1785 and 9 VAC 5-80-2050)

EMISSION OFFSETS

44. **NO_X (and VOC) Offsets –** The permittee shall secure NO_X emission offsets if the GE 7FA.05 combustion turbines are installed, and NO_X and VOC emission offsets if the Siemens SGT6-5000F5 combustion turbines are installed in accordance with 9 VAC 5-80-2120 and 40 CFR Part 51, Appendix S. The emission offsets are based on total annual facility-wide emissions. The offsets shall, at a minimum, meet the following conditions:

a. The permittee shall secure NO_X emission offsets of no less than 159 tons x 1.15 = 182.85 tons for the GE 7FA.05 combustion turbines, and 164.9 tons x 1.15 = 189.64 tons for the Siemens SGT6-5000F5 combustion turbines. The permittee shall secure VOC emission offsets of no less than 51.9 tons x 1.15 = 59.69 tons for the Siemens SGT6-5000F5 combustion turbines.

b. The emission reduction credits shall be creditable, surplus, quantifiable, permanent and state and federally enforceable. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 CFR Part 51, App S, Subsection IV.C.

c. The offsets shall be obtained within the Northern Virginia ozone nonattainment area or from another ozone nonattainment area. If the offsets are obtained from another ozone nonattainment area, the following requirements apply:

   i. The ozone nonattainment area must have an equal or higher nonattainment classification than the area in which the source is to be located.

   ii. For any offsets secured from outside of the Commonwealth of Virginia, the emission reductions must be certified to be surplus, quantifiable, permanent and state and federally enforceable by the state or locality where the emission reductions occurred. Documentation of the certification must be provided to and approved by the DEQ Northern Regional Office prior to the beginning of operation of the facility.

d. Prior to beginning operation, the offsets shall be secured, in effect, and state and federally enforceable.

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(9 VAC 5-80-2120 and 40 CFR Part 51, Appendix S)

45. **Offset Timing** – Initial startup and operation of the permitted equipment shall not be initiated until the permittee has provided the DEQ-NRO with an official document from the DEQ and / or the State Agency of the state the offsets were obtained indicating that it recognizes the reduction as creditable and permanent. At a minimum, the document shall state that the emission reduction has not been and will not be credited toward another reduction requirement and that the emissions cannot be resurrected from the same facility without the owner first obtaining a permit under a federally-enforceable new source review program. The document must also provide evidence that the U.S. EPA accepts that the emission reductions are creditable for offset purposes.
(9 VAC 5-80-2120 and 9 VAC 5-80-2050 A.3.a)

46. **Offset Recordkeeping -** The permittee shall maintain at the permitted facility a copy of the following:

   i. Identification of each source from which the offsets were obtained. Identification shall include the name, address, and Universal Transverse Mercator (UTM) coordinates of the facility and any identification number assigned to the facility by the air pollution control facility that regulates it.
   ii. Certification Document from each air pollution control agency required by Condition 44.c and any supporting documentation.

(9 VAC 5-80-2050 and 9 VAC 5-80-2120)

CONTINOUS EMISSION MONITORING SYSTEMS (CEMS)

47. **CEMS –** Continuous Emission Monitoring Systems (CEMS) shall be installed on CCT1 and CCT2 to measure and record the emissions of NO_X (measured as NO_2) and carbon monoxide (CO), in parts per million by volume (ppmvd) corrected to 15 percent O_2, from each combined-cycle power generating unit (Ref. No. CCT1 & CCT2). CEMS shall also be installed to measure and record the emissions of carbon dioxide (CO2). The NOx CEMS shall be installed, evaluated, and operated, and meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the "Monitoring Requirements" in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_X and CO emissions are monitored. Heat input and power output shall also be measured and recorded. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 33, NO_X data and CO data shall each be reduced to one-hour rolling blocks. The relative accuracy test audit (RATA) of the NO_X/O_2 CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-410, 9 VAC 5-50-420, 40 CFR 75, 40 CFR 60.13, and 40 CFR 60.4340 (b))

48. **CEMS Performance Evaluations (NO_X CEMS)–** Performance evaluations of the NO_X and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR 75, Appendix B , and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting the initial performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written requirements or recommendations for demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 75, and 40 CFR 60.4345(a))

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49. **CEMS Performance Evaluations (CO CEMS) –** Performance evaluations of the CO CEMS shall be conducted in accordance with 40 CFR 60, Appendix B, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting the initial performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written requirements or recommendations for demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 60, and 40 CFR 60.4345(a))

50. **CEMS Quality Control Program –** For the NO_X and diluent CEMS, the quality control requirements of 40 CFR Part 75 shall be met. The Quality Assurance Accuracy Specifications for the CO CEMS shall be 40 CFR 60 Appendix F, Procedure 1. A linearity test for NO_X and diluent, and a Cylinder Gas Audit (CGA) for CO shall be performed once per QA operating quarter (≥ 168 hours operation) not to exceed four calendar quarters. A RATA test for each installed CEMS shall be conducted once every four Quality Assurance (QA) operating quarters (≥ 168 hours operation each), not to exceed eight calendar quarters. The provisions for a grace period to complete testing shall apply (40 CFR 75, Appendix B 2.2.4 & 2.3.3). Data validation shall be as defined in 40 CFR Part 75, Appendix

B, 2.3.2 with the exception that missing data for CO, resulting from continuous monitor system breakdown, repair, calibration checks, and zero and span adjustments, shall be reported as monitor downtime and not substituted. No bias factor shall be applied to the CO monitored value as per 40 CFR Part 60.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4543(e), and 40 CFR 60)

51. **Excess Emissions and Monitor Downtime for NO_X Continuous Monitoring Systems –** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 53 are defined as follows:

    a. An excess emission is any unit operating period in which the one-hour average NO_X emission rate exceeds the applicable emission limit in Condition 33, and

    b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee uses this information for compliance purposes.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

52. **Excess Emissions and Monitor Downtime for SO_2 Monitoring Systems:** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 53 are defined as follows:

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    a. An excess emission occurs each unit operating hour included in the hour beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

    b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

53. **Reports for Continuous Monitoring Systems –** The permittee shall furnish written reports to the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57 from any process monitored by a CEMS, on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions. For each month in the quarter, report each hour in which a NO_X permit limit is exceeded. The report shall include for each excess emission of NO_X: start time, duration, equipment involved, actual NO_X emissions in ppmvd @ 15% O_2, fuel consumption rate, actual weather conditions (temperature and barometric pressure) and turbine load.

b. Specific identification of each period of excess emissions that occur during startups, shutdowns or malfunctions of the process, and the nature and cause of the malfunction the corrective action taken, and preventative measures adopted;

c. The date and time identifying each time period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments;

d. If during the calendar quarter no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

Copies of the written notification referenced in items a and d above are to be sent to:

Associate Director
Office of Air Enforcement (3 AP 10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA19103 – 2029

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a), and 40 CFR 60.4395)

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54. **Excess Emissions for Continuous Monitoring Systems –** For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm, using the appropriate equation in 40 CFR 60, Appendix A Method 19. For any hour in which the hourly average of O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.'

c. Correction of measured NO_X concentrations to 15 percent O_2 is not allowed; and

d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

TESTING

55. **Testing/Monitoring Ports –** The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stacks and ducts that are free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendices A & B). (9 VAC 5-50-30 F)

56. **Initial Performance Test (CO, VOCs, PM-10 & PM-2.5) – Combustion Turbines -** Initial performance tests shall be conducted on each combined-cycle power generation unit (Ref. No. CCT1 & CCT2) for the following pollutants using the specified methods, as appropriate:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile Organic Compounds (VOC)	40 CFR 60, Appendix A, Method 25A
PM-10 & PM-2.5 (includes condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19 and 40 CFR 51, Appendix M, Method 201A and 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 33. The tests shall be performed, reported and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated, but in no event later than 180 days after startup of the permitted unit. The tests shall be conducted on each combined-cycle power generation unit for two different operating scenarios: natural gas firing with the duct burners off; and natural gas firing with the duct burners on. The tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Should conditions occur which would require rescheduling the testing, the permittee shall notified the Regional Air Compliance Manager of the DEQ's NRO in writing, no less than seven days prior to the scheduled test date or as soon as the rescheduling is set. In any case the emissions testing shall be rescheduled within 30 days. Two copies of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-2080)

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57. **Correspondence -** All correspondence to DEQ concerning compliance with this permit shall be submitted to the following address:

Regional Air Compliance Manager
Department of Environmental Quality
Northern Regional Office
13901 Crown Court
Woodbridge, VA 22193

(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-2050)

58. **Initial Performance Test (NOx) – Combustion Turbines -** Initial performance tests shall be conducted on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) for oxides of nitrogen (as NO_2) to determine compliance with the limits in Condition 33 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_X concentration (in ppm). Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non particulate procedures), and sampled for equal time intervals. The sampling must be performed with a transversing single hole probe, or, if feasible, with a stationary multi probe hole that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 58a above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met:

   The permittee may perform stratification tests for NO_X and dilutant pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use following alternate sample point section criteria for the performance test:

   i. If each of the individual transverse point NO_X concentrations is within +- 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differ by no more than +-5 ppm, or +- 5 percent O_2 from the mean for all traverse points, three points located either 16.7, 50.0, or 83.3 percent of the way across the stack or duct, or for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2 and 2.0 meters from the wall may be used. The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test, or

   ii. The permittee may sample at a single point, located at least one meter from the stack wall or at the stack centroid if each of the individual transverse point NO_X concentrations is within +- 2.5 percent of the mean concentration for all transverse points, or the individual transverse point diluent concentration differs by no more than +- 1 ppm or +- 0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition within +- 25 percent of 100 percent peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_X emissions after the duct burner rather than after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 33 must be demonstrated at each tested load level. Compliance is achieved if the three run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in Condition 33.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

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g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following alternatives to the reference methods and procedures in this condition:

   i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

   ii. Compliance with the applicable emission limits in Condition 33 is achieved if the arithmetic average of all the NO_X emission rates for the RATA runs, expressed in ppm, does not exceed the emissions limit.

The tests shall be performed, reported and demonstrate compliance within sixty days after achieving the maximum production rate at which the unit will be operated, but in no event later than 180 days after startup of the permitted unit. Tests shall be conducted and reported and the data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section of 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405 and 40 CFR 60.4400)

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59. **Initial Performance Test (SO_2) – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) for sulfur dioxide (SO_2) to determine compliance with the limits in Condition 33. The permittee may use one of the following three (a, b, or c below) to conduct the performance test:

   a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) or by manually sampling using Gas Process Association Standard 2166 for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternately D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

   b. 40 CFR 60, Appendix A, Methods 6, 6C, 8 or 20 shall be used to measure the SO_2 concentration (in ppm). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9-10-1981-Part 10 "Flue and Exhaust Gas Analysis", manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

   c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use manual methods

for sulfur dioxide ASME PTC 9-10-1981-Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated, but in no event later than 180 days after startup of the permitted unit. Tests shall be conducted and reported and the data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section of 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion, but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405 and 40 CFR 60.4400)

60. **Initial Performance Test – Auxiliary Boiler and Fuel Gas Heater -** Initial performance tests shall be conducted on the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) for NO_X and CO to determine compliance with the emission limits in Conditions 37 and 38. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days of the test completion but no later than 180 days from after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-80-2080)

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61. **Visible Emissions Evaluation – Combustion Turbines** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) exhaust stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The tests shall be conducted on each combined-cycle power generation unit for two different operating scenarios: natural gas firing with the duct burners off; and natural gas firing with the duct burners on. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the listed referenced in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed within 60 days after achieving the maximum production rate at which the unit will be operated, but in no event later than 180 days after start-up of the permitted unit.

Should conditions occur which require rescheduling the testing, the Regional Air Compliance Manager of the DEQ's NRO shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. Two copies, one hard copy and one electronic copy on removable electronic media, of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within

60 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050 and 9 VAC 5-80-2080)

62. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted on the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) exhaust stacks. Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six minute average. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed within 60 days after achieving the maximum production rate at which the boiler or fuel gas heater, as applicable, will be operated, but in no event later than 180 days after start-up of the permitted unit.

    Should conditions occur which require rescheduling the testing, the Regional Air Compliance Manager of the DEQ's NRO shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. Two copies, one hard copy, and one on removable electronic media of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit
    (9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-80-2080)

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63. **Testing: Heat Rate Limit –** Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the DEQ's NRO, shall be conducted for the heat rate limit of the combined cycle power generating plant (i.e., a combination of the combustion turbines, HRSG DBs and the steam turbine generator) to show compliance with the heat rate limit contained in Condition 2.d. The testing shall be performed, reported and demonstrate compliance within 90 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. The details of the tests are to be arranged with DEQ's NRO. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days of the test completion but no later than 180 days from after startup of the permitted unit and shall conform to the test report format enclosed with this permit. An exceedance of the heat rate limit is not considered a violation of this permit, but triggers a requirement for the permittee to submit a maintenance plan to DEQ's NRO which specifies the actions the permittee plans to take in order to achieve the heat rate limit contained in Condition 2.d. The details of this plan are to be arranged with DEQ's NRO.
    (9 VAC 5-50-30 and 9 VAC 5-80-1675)

64. **Annual SO_2 Performance Test – Combustion Turbines** – Annual performance tests shall be conducted on each combined-cycle combustion turbine (Ref. No. CCT1 & CCT2) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 33. The permittee may use one of the following three methods (a, b, or c below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) or by manually sampling using Gas Process Association Standard 2166 for natural gas. The fuel analysis may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternately D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference , see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8 or 20 shall be used to measure the SO_2 concentration (in ppm). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9-10-1981-Part 10 "Flue and Exhaust Gas Analysis", manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use manual methods for sulfur dioxide ASME PTC 9-10-1981-Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Regional Air Compliance Manager of the DEQ's NRO at the address listed in Condition 57. The permittee shall submit a test protocol at least 30 days prior to testing. Two copies of the test results shall be submitted to the Regional Air Compliance Manager of the DEQ's NRO within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, 9 VAC 5-50-410, and 40 CFR 60.4415(a))

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65. **Biennial VOC, PM-10 & PM-2.5 Performance Test – Combustion Turbines -** Upon completion of the initial performance tests required by Condition 56, the permittee shall conduct biennial performance tests on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) at 24 month intervals for VOC PM-10, and PM-2.5 emissions as prescribed in Condition 56. The first such biennial test event shall occur no later than 24 months following completion of the initial performance tests required by Condition 56. If during three consecutive test events, including the initial performance tests, neither unit has tests results that show emissions at greater than 80 percent of the emission limits in Condition 33, the testing interval for each turbine may be expanded up to 60 months upon approval from the Regional Air Compliance Manager of the DEQ's NRO. If any subsequent test results in emissions of greater than 80 percent, biennial testing at no more than 24 month intervals shall resume. The tests for each turbine may be staggered within the schedule above, so that they are not necessarily conducted for both units in the same calendar year. The tests need only be conducted at the maximum load in the normal operating range and the minimum load of the normal operating range, unless the minimum load is within ten percent of the maximum load, in which case testing is required at only the maximum load. The normal operating range shall be determined from records of actual operation. Upon request by the DEQ, the permittee shall conduct additional performance tests for each combined-

cycle power generating unit (Ref. No. CCT1 & CCT2) to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be agreed upon with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 G, 9 VAC 5-80-1180, 9 VAC 5-80-2050, 9 VAC 5-80-2080, and 9 VAC 5-50-410)

66. **Visible Emissions Evaluation – Combustion Turbines** – After the initial Visible Emissions Evaluation, the permittee shall conduct visible emission inspections on each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) stack in accordance with the following procedures and frequencies:

    a. At a minimum of once per week, the permittee shall observe the exhaust stack of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) when in operation for the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the individual observations exceed the applicable standard, the VEE shall be continued for 60 minutes.

    b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by the DEQ, the monitoring frequency shall be increased to once per week for that stack.

    c. The details and results of all visible emission inspections and observations, and VEEs shall be recorded. The permittee shall maintain records of all such events.

    (9 VAC 5-50-20 and 9 VAC 5-80-2080)

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67. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** –The permittee shall conduct visible emission inspections on the auxiliary boiler (Ref. No. AB1) and fuel gas heater (Ref. No. FGH1) stacks in accordance with the following procedures and frequencies:

    a. At a minimum of once per month, the permittee shall observe the exhaust stack of the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) when in operation for the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be continued for 60 minutes.

    b. If visible emission inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by the DEQ, the monitoring frequency shall be increased to once per month.

    c. The details and results of all visible emission inspections and observations, and VEEs shall be recorded. The permittee shall maintain records of all such events.

(9 VAC 5-50-20 and 9 VAC 5-80-2080)

68. **Periodic Testing: Heat Rate Limit –** Every five years after initial evaluation of the heat rate limit of the power generation block, the permittee shall conduct a heat rate evaluation of the power generation block to show compliance with the heat rate limit contained in Condition 2 d. The details of the evaluation are to be arranged with DEQ's NRO.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

69. **Stack Tests** – Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the stack tests shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO.
(9 VAC 5-50-30 G)

RECORDKEEPING

70. **On Site Records** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Regional Air Compliance Manager of the DEQ's NRO. These records shall include, but are not limited to:

    a. Fuel records to demonstrate compliance with Conditions 11, 12 and 13.

    b. Fuel monitoring device QA/QC for the CEMS per 40 CFR Part 75.

    c. Monthly and annual throughput of natural gas to each combustion turbine (Ref. No. CT1 & CT2). calculated monthly as the sum of each consecutive 12 month period.

    d. Monthly and annual throughput of natural gas to each duct burner (Ref. No. DB1 & DB2), calculated monthly as the sum of each consecutive 12-month period.

    e. Time, date, and duration of each startup, shutdown, malfunction and turbine retuning period for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2).

    f. Annual number of startup and shutdown occurrences for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2), calculated monthly as the sum of each consecutive 12-month period.

    g. Emissions calculations sufficient to verify compliance with the annual emission limits in Condition 35 (Ref. No. CCT1 & CCT2), Condition 37 (Ref. No. AB1), Condition 38 (Ref. No. FGH1), Condition 40 (Ref. No. EG1), Condition 41 (Ref. No. EFP1), Condition 42 (Ref. No. MCT1 – MCT10), and facility-wide emission limits in Condition 43, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the Regional Air Compliance Manager of the DEQ's NRO

    h. Monthly total dissolved solids sampling results from the water used by the ten cell mechanical draft cooling tower.

    i. Continuous records of heat input for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2).

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j. Continuous records of power output for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) and the steam turbine generator.

k. Continuous monitoring systems emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

l. Annual hours of operation for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period.

m. Records of time, date and duration of operation for the emergency fire water pump (Ref. No. EFP1) and the emergency generator (Ref. No. EG1) for maintenance checks and readiness testing and the operational status of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) during those maintenance checks and readiness testing.

n. Annual hours of operation for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period.

o. All fuel supplier certifications for the emergency generator (Ref. No. EG1) and the emergency fire pump (Ref. No. EFP1) to demonstrate compliance with Condition 13.

p. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

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q. Logs of dissolved solids content of cooling water to the ten cell mechanical draft cooling tower (Ref. No. MCT1- MCT10)

r. Records for each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) showing steady state vs. non steady state operation during a given hour, the ammonia emissions monitoring plan, and the ammonia emission monitoring results as required by Condition 31.

s. Scheduled and unscheduled maintenance and operator training.

t. Results of all stack tests, visible emissions evaluations, visible emission inspection results, and performance evaluations.

u. Monthly and annual throughput of natural gas and hours of operation for the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1), calculated monthly as the sum of each consecutive 12-month period.

v. Records of manufacturer's instructions for proper operation of equipment for the auxiliary boiler (Ref. No. AB1) and the fuel gas heater (Ref. No. FGH1) as required by Condition 3.

w. Records related to NO_X offsets as required by Conditions 44, 45 and 46.

x. Records related to the CEMS quality control program as required in Condition 50.

y. Records to verify compliance with the short term emission factors for GHG in Conditions 33 and 34.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-80-2050, and 9 VAC 5-50-50)

NOTIFICATIONS

71. **Initial Notifications** – The permittee shall furnish written notification to the Regional Air Compliance Manager of the DEQ's NRO of:

a. The actual date on which the construction of the electric power generation facility begins within 30 days after such date.

b. The actual date of the selection of the turbine and HRSG manufacturer has been selected including model number, and heat input rating within 30 days after such date.

c. Date that emission offsets are identified, and the nature of the offsets within 30 days after such date.

d. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

e. The actual start-up date of the electric power generation facility within 15 days after such date.

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f. The anticipated date of continuous monitoring system (CEMS) performance evaluations postmarked not less than 30 days prior to such date.

g. The anticipated date of performance tests of each combined-cycle power generating unit (Ref. No. CCT1 & CCT2) postmarked at least 30 days prior to such date.

h. The actual date on which construction of the auxiliary boiler (Ref. No. AB1) commenced within 30 days after such date.

i. The anticipated start-up date of the auxiliary boiler (Ref. No. AB1) postmarked not more than 60 days nor less than 30 days prior to such date.

j. The actual start-up date of the auxiliary boiler (Ref. No. AB1) within 15 days after such date.

k. The actual date on which construction of the emergency generator (Ref. No. EG1) and emergency fire water pump (Ref. No. EFP1) commenced within 30 days after such date. The notification must contain the following:

i. Name and address of the permittee,
ii. The address of the affected source,
iii. Engine information including make, model, engine family, serial number, model year, maximum engine power and engine displacement.
iv. Fuel used

l. The anticipated start-up date of the emergency generator (Ref. No. EG1) and emergency fire water pump (Ref. No. EFP1) postmarked not more than 60 days nor less than 30 days prior to such date.

m. The actual start-up date of the emergency generator (Ref. No. EG1) and the emergency fire water pump (Ref. No. EFP1) within 15 days after such date.

Copies of the written notification referenced in items a through d and f through h above are to be sent to the Associate Director of the U.S. EPA at the address in Condition 53.
(9 VAC 5-50-50 and 9 VAC 5-80-1180)

GENERAL CONDITIONS

72. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction is not commenced within 18 months from the date of this permit:

    b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time. This provision does not apply to the period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

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DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified
(9 VAC 5-80-1210, 9 VAC 5-80-1985 and 9-VAC 5-80-2180)

73. **Permit Suspension/Revocation** - The Board may suspend or revoke any permit if the permittee:

    a. Knowingly makes material misstatements in the permit application or any amendments to it;

    b. Fails to comply with the terms or conditions of this permit;

    c. Fails to comply with any emission standards applicable to an emissions unit included in this permit;

    d. Causes emissions from the facility which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard;

    e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan if effect at the time an application for this permit is submitted

    (9 VAC 5-80-1210 F, 9 VAC 5-80-1985 F and 9 VAC 5-80-1210 G)

74. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

75. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility, including associated air pollution control equipment, in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Air Compliance Manager of the DEQ's NRO, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

    The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9 VAC 5-50-20 E, 9 VAC 5-80-1180 D, and 9 VAC 5-80-2050)

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76. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shut-down or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. The records shall be maintained in a form suitable for inspection and maintained for at least two years (unless a longer period is specified in the applicable emission standard) following the date of occurrence. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause of malfunction), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J, 9 VAC 5-80-1180 D, and 9 VAC 5-80-2050)

77. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the DEQ, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable, but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again operating the permittee shall notify the DEQ, in writing.
(9 VAC 5-20-180 C, 9 VAC 5-80-1180, and 9 VAC 5-80-2050)

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78. **Notification for Control Equipment Maintenance** - The permittee shall furnish notification to the Regional Air Compliance Manager of the DEQ's NRO in case of shutdown or bypassing, or both, of air pollution control equipment for necessary scheduled maintenance, which results in excess emissions for more than one hour. The intent to shut down or bypass such equipment shall be reported to the Regional Air Compliance Manager of the DEQ's NRO and local air pollution control agency, if any, at least 24 hours prior to the planned shutdown. Such prior notice shall include, but is not limited to the following information:

    a. Identification of air pollution control equipment to be taken out of service, as well as its location and registration number;

    b. The expected length of time that the air pollution control equipment will be out of service;

    c. The nature and quantity of emissions of air pollution likely to occur during the shutdown period; and

    d. Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

    (9 VAC 5-20-180 B)

79. **Violation of Ambient Air Quality Standard** - Regardless of any other provision of this permit, the permittee shall, upon request of the DEQ, reduce the level of operation of the facility if the DEQ determines that is necessary to prevent a violation of any primary ambient air quality standard. Under worst-case conditions, the DEQ may order that the permittee shut down the facility if there is no other method of operation to avoid a violation of the

primary ambient air quality standard. The DEQ reserves the right to prescribe the method of determining if a facility will cause such a violation. In such cases, the facility shall not be returned to operation until it and the associated air pollution control equipment are able to operate without violation of any primary ambient air quality standard.
(9 VAC 5-20-180 I)

80. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the DEQ of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985 E and 9 VAC 5-80-1240 B)

81. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180, 9 VAC 5-80-1985 E and 9 VAC 5-80-2050)

STATE ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

82. **Emission Limits** – Emissions from the electric power generation facility shall not exceed the limits specified below:

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Pollutant	CAS#	lb/hr	Tons/yr
Acrolyn	107-02-8	2.03E-02[a]/2.06 E-02[b]	8.76E-02[a]/ 8.88E-02[b]
Formaldehyde	50-00-0	7.65E-01[a]/7.54E-01[b]	3.09E-00[a]/ 3.11E-00[b]
Cadimum	7440-43-9	6.31E-03[a]/5.95E-03[b]	2.25E-02[a]/2.25E-02[b]
Chromium	7440-47-3	8.04E-03[a]/7.57E-03[b]	2.86E-02[a]/2.86E-02[b]
Nickel	7440-02-0	1.21E-02[a]/1.14E-02[b]	4.29E-02[a]/4.29E-02[b]

[a] Emissions based on GE 7FA.05
[b] Emissions based on Siemens SGT6-5000F5

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

83. **Onsite Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Northern Regional Office. These records shall include, but are not limited to the average hourly, monthly, and annual emissions (in pounds and tons) listed in Condition 82 for each toxic compound using the appropriate emission factor from AP-42, (Section 3-1 dated 4/2000 for stationary gas turbines), (Section 1.4 dated 7/1998 for natural gas combustion), (Section 3.3 dated 4/2000 for gasoline and diesel industrial engines) and (Section 3.4 dated 4/2000 for large stationary dual fuel engines) times the appropriate fuel usage for the period.. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by the DEQ and current for at least the most recent five years.

(9 VAC 5-50-50 and 9 VAC 5-80-1625G)

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SOURCE TESTING REPORT FORMAT

Report Cover

1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification

1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary

1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
    a. Operating rate
    b. Test Methods
    c. Pollutants tested
    d. Test results for each run and the run average
    e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

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Source Operation

1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results

1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix

1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

* Not applicable to visible emission evaluations

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

VALLEY REGIONAL OFFICE

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December 21, 2010

Mr. Robert B. McKinley
Vice President, Generation Construction
Dominion Resources Service Inc.
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility: Warren County Power Station
Location: Warren County
Registration No.: 81391
Plant ID No.: 51-187-0041

Dear Mr. McKinley:

This letter is in regard to the permit to construct and operate an electric generating facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution, which was hand delivered to Virginia Electric and Power Company on December 17, 2010. This permit supersedes your permit dated July 30, 2004, as amended March 29, 2006, June 5, 2007, January 14, 2008, and September 15, 2009.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on September 3, 2010, and solicited written public comments by placing a newspaper advertisement in the Northern Virginia Daily newspaper on October 9, 2010. A public hearing was held on November 9, 2010. The required comment period, provided by 9 VAC 5-80-1870, expired on November 24, 2010. The State Air Pollution Control Board gave direct consideration to the proposed permit at its December 17, 2010 meeting and instructed DEQ to issue the permit on its behalf.

This permit approval to construct and operate shall not relieve Virginia Electric and Power Company of the responsibility to comply with all other local, state, and federal permit regulations.

The proposed emergency generator (EG-1) and emergency fire water pump (FWP-1) appear to be affected facilities under the NSPS *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* (located at 40 CFR 60, Subpart IIII) and the Maximum Achievable Control Technology (MACT) *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* (located at 40 CFR 63, Subpart ZZZZ). DEQ advises you to review the NSPS and MACT regulations to ensure compliance with the applicable emission and operational limitations. As the owner/operator, you are responsible for the monitoring, notification, recordkeeping, and reporting requirements of these NSPS and MACT regulations. Notifications should be sent to the U.S. Environmental Protection Agency, Region III.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

A copy of the results of performance tests required by 40 CFR 60, Subparts Dc, IIII, and KKKK shall be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

If you have any questions concerning this permit, please call Anita Riggleman of the Valley Regional Office at (540) 574-7852.

Sincerely,

Amy T. Owens
Regional Director

Attachments: Permit
40 CFR Part 60, Subparts Dc, IIII, and KKKK (via electronic mail)
40 CFR Part 63, Subpart ZZZZ (via electronic mail)

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Air Enforcement Branch (3AP20), U.S. EPA, Region III
Inspector, Air Compliance
Gerallyn Duke, U.S. EPA, Region III (electronic file submission)

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

VALLEY REGIONAL OFFICE
4411 Early Road, P.O. Box 3000, Harrisonburg, Virginia 22801
(540) 574-7800 Fax (540) 574-7878
www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

Amy Thatcher Owens
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS) and National Emission Standards
for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

This permit supersedes your permit dated July 30, 2004, as amended March 29, 2006, June 5, 2007, January 14, 2008, and September 15, 2009.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 81391
Plant ID No.: 51-187-0041

is authorized to construct and operate

an electric power generation facility

located at

Lots 3, 5, 6, 7, 8, 9, and 10, Warren Industrial Park
Warren County

in accordance with the Conditions of this permit.

Approved: Amy R Owens
Regional Director

17 December 2010
Signature Date

Permit consists of 35 pages.
Permit Conditions 1 to 75.
Source Testing Report Format
Attachments A and B

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition. All parts per million (ppm) are parts per million by volume on a dry gas basis (ppmvd), corrected to 15 percent oxygen, unless otherwise stated. All heat inputs in British thermal units (Btu) are based on higher heating values.

INTRODUCTION

This permit approval is based on the permit applications dated January 7, 2010, January 18, 2010, February 12, 2010, March 16, 2010, April 14, 2010, April 23, 2010, June 24, 2010, July 2, 2010, July 27, 2010, August 6, 2010, August 24, 2010, August 27, 2010, September 1, 2010 (2 items), September 2, 2010, and September 24, 2010 and supplemental information dated April 27, 2010 and May 20, 2010. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. Equipment List

Equipment to be constructed at this facility consists of:

- three combined-cycle power generating units (T-1, T-2, & T-3) where each unit includes the following emission units:

- one Mitsubishi natural gas-fired combustion turbine (CT) generator, Model M501 GAC, rated at 299,600 kW and 2,996 million Btu per hour heat input (CT-1, CT-2, & CT-3) (NSPS Subpart KKKK); and
- one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1, DB2, & DB3) (NSPS Subpart KKKK);

– one natural gas-fired auxiliary boiler, rated at 88.1 million Btu per hour heat input (B-1) (NSPS Subpart Dc);

– one natural gas-fired fuel gas heater, rated at 52.0 million Btu per hour heat input (GH-1) (NSPS Subpart Dc);

– one diesel-fired emergency generator, rated at 2,193 HP (EG-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (FWP-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– three turbine inlet chillers (600,000 gal/hr each) (IC-1, IC-2, & IC-3); and

– one 6,000 gallon distillate oil storage tank (ST-1).

(9 VAC 5-80-1100 and 9 VAC 5-80-1605 A)

PROCESS REQUIREMENTS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

2. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by use of a two-stage, lean pre-mix dry low-NO_x combustor, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practices. The SCR system shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

3. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

4. **Emission Controls: Volatile Organic Compounds** – Volatile Organic Compound (VOC) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

5. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

6. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

7. **Monitoring Device Observation: SCR** – The devices used to continuously measure ammonia feed rate, gas stream flow rate, and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

8. **Monitoring Device Observation: Oxidation Catalyst** - The devices used to continuously measure catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

PROCESS REQUIREMENTS - EMERGENCY UNITS (EG-1 & FWP-1)

9. **Monitoring Devices –** The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the

startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-80-1180 D and 40 CFR 60.4209)

10. **Maintenance and Operation** – The permittee must maintain and operate the emergency generator (EG-1) and the emergency fire water pump (FWP-1) according to the manufacturer's written instructions, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.4206 and 40 CFR 60.4211)

PROCESS REQUIREMENTS - AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)

11. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by ultra low-NO_x burners.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

12. **Emission Controls: Carbon Monoxide and Volatile Organic Compounds** - CO and VOC emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by good combustion practices, operator training and proper emissions unit design, construction and maintenance. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations, at minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

OPERATING/EMISSION LIMITATIONS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

13. **Fuel** - The approved fuel for each CT (CT-1, CT-2, & CT-3) and each HRSG duct burner (DB1, DB2, & DB3) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, and 40 CFR 60.4330(a)(2))

14. **Fuel Throughput** – The combustion turbines (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) combined shall consume no more than 90,073 x 10^6 scf of natural

gas per year. Throughput shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

15. **Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas being fired at the electric power generation facility is 0.0003 percent by weight or less (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet), to demonstrate that potential sulfur dioxide emissions shall not exceed the limits specified in Condition 16.

If the permittee elects not to demonstrate the sulfur content using the above option, the permittee may:

a. determine and record the total sulfur content of the natural gas once per unit operating day or

b. develop custom schedules for determination of the total sulfur content of the natural gas, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

(9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.4365(a), 40 CFR 60.4370(b) and 40 CFR 60.4370(c))

16. **Short-Term Emission Limits** - Emissions from the operation of each combined-cycle power generating unit (T-1, T-2, & T-3) shall not exceed the limits specified below:

	Short term emission limits
PM-10 (includes condensable PM)	▪ 8.0 lb/hr without duct burner firing ▪ 14.0 lb/hr with duct burner firing ▪ 0.0027 lb/MMBtu without duct burner firing ▪ 0.0040 lb/MMBtu with duct burner firing
PM-2.5*	▪ 8.0 lb/hr without duct burner firing* ▪ 14.0 lb/hr with duct burner firing* ▪ 0.0027 lb/MMBtu without duct burner firing* ▪ 0.0040 lb/MMBtu with duct burner firing*
Sulfur dioxide	▪ 0.98 lb/hr ▪ 0.00028 lb/MMBtu
Oxides of nitrogen (as NO_2)	▪ 25.3 lb/hr ▪ 2.0 ppmvd
Carbon monoxide	▪ 9.9 lb/hr and 1.5 ppmvd without duct burner firing ▪ 17.4 lb/hr and 2.4 ppmvd with duct burner firing

Volatile organic compounds	▪ 2.6 lb/hr and 0.7 ppmvd without duct burner firing ▪ 6.1 lb/hr and 1.6 ppmvd with duct burner firing
Sulfuric acid mist (H_2SO_4)	▪ 0.00013 lb/MMBtu without duct burner firing ▪ 0.00025 lb/MMBtu with duct burner firing

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides and carbon monoxide, which shall be calculated as a one-hour average.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 18 of this permit.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, and 43.

* This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4320, and 40 CFR 60.4330)

17. **Annual Emission Limits –** Total emissions from the operation of all three combined-cycle power generating units (T-1, T-2, & T-3) including duct burners shall not exceed the limits specified below:

Pollutant	Annual Emissions (tons)
PM-10 (includes condensable PM)	159.1
PM-2.5	159.1*
Sulfur Dioxide	12.3
Oxides of Nitrogen (as NO_2)	317.7
Carbon Monoxide	348.6
Volatile Organic Compounds	181.0
Sulfuric Acid Mist (H_2SO_4)	9.5

* This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, 14, and 43.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

18. **Startup/Shutdown** – The short-term emission limits contained in Condition 16 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed 4.2 hours per occurrence.

ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed 2.1 hours per occurrence.

iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 1.5 hours per occurrence.

iv. Shutdown – refers to the period between the time the turbine load drops below 60 percent operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 0.5 hours per occurrence.

b. The permittee shall operate the Continuous Emission Monitoring Systems (CEMS) during periods of startup and shutdown.

c. The permittee shall record the time, date and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180, and 9 VAC 5-80-1705)

19. **Emission Limits: Duct Burners** – Emissions from the operation of each duct burner (DB1, DB2, & DB3) operating independently of each combined-cycle system (T-1, T-2, & T-3) shall not exceed 54 ppm of oxides of nitrogen (expressed as NO_2) at 15 percent O_2.
(9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4320)

20. **Duct Burner Operational Restriction** – The duct burners (DB1, DB2, & DB3) shall not operate between the hours of 10 p.m. and 5 a.m. Eastern Standard Time (EST) during the period between September 1st and April 30th, except that the duct burners may be operated during a Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) Independent System Operator's (ISO) declared emergency. This duct burner operational restriction is included to demonstrate that the project will not cause or contribute to an exceedance of the applicable PM-2.5 PSD Class I increment as of the trigger date, October 20, 2011.
(9 VAC 5-80-1180, Virginia Code 10.1 1307.02., and Virginia Code 10.1-1307.3 A.5.)

21. **Pollution Prevention: Ammonia** – Emissions of ammonia resulting from unreacted ammonia emitted from the SCR (ammonia slip) shall not exceed 2 ppmvd during steady-state conditions and 5 ppmvd during non-steady-state operations. Compliance with the ammonia slip limit shall be determined based on a one-hour block average. Steady-state operation is based on a steady load for the duration of the CEMs hour and is defined as less than a 5% rate of load change within the hour. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia slip and demonstrating compliance with the ammonia slip limit from each SCR system to the DEQ. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia slip limit at least 95% of the time the SCR is operating. Compliance with the 95% time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior 30 days, compliance with the 95 percent limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 5-170-160, and Virginia Pollution Prevention Act, § 10.1-1425.11)

22. **Visible Emission Limit** - Visible emissions from each combined-cycle (T-1, T-2, & T-3) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 18), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260, and 9 VAC 5-80-1705)

23. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the CTs (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

AIR QUALITY RELATED VALUES

24. **Source Reductions and Emission Offsets –** The permittee shall implement the following actions to secure a total of emission offsets equal to the Total Annual NO_x Limit, (i.e. the sum of NO_x limits for the combustion turbines, duct burners and emergency engines in Conditions 17, 30, 31, 39, and 40) ("TANL") at the Facility. The National Park Service has determined that for the Warren County Power Station these actions provide full mitigation or acceptable net environmental benefits for all potential or actual adverse impacts to Air Quality Related Values, including visibility and aquatic resources, at Shenandoah National Park (SNP).

a. Definitions – Solely for the purposes of this permit Condition 24, the following definitions shall apply:

i. "Emissions Offsets" means Emission Reduction Credits, Allowances under the Acid Rain Program or other emissions reductions that are obtained to mitigate potential impacts of the permitted facility on the air quality and related values in SNP.

ii. "Eligible SO_2 Allowances" mean those Allowances (as defined in the Clean Air Act, section 402(3)) that originate from Dominion owned facilities in the region shown on Attachment A ("Originating Account").

iii. "Eligible NO_x Allowances" mean any NO_x Allowances as that term is defined in a federally-approved NO_x emissions trading program.

iv. "Facility NO_x Emission Ton" means each ton of NO_x emissions from the permitted facility.

v. "Allowable Annual NO_x Emissions" means 330.7 tons NO_x per year, which represents the maximum Facility NO_x Emission Tons authorized under the permit.

vi. "Emissions Reduction Credits" means the number of tons per year of creditable emissions reductions.

vii. "Offset Ratio" means the ratios shown on the map at Attachment A.

b. Emission Offsets from specific facilities – The permittee shall secure a reduction in emissions from a source or sources in the manner prescribed as follows:

i. The permittee shall permanently cease all permitted SO_2 and NO_x emissions at North Branch Power Station in Grant County, West Virginia. Based on the actual emissions in 2007-2008 and the distance and direction of North Branch Power Station from the Park these reductions shall result in an Emission Offset of 243 TPY toward the TANL offset requirement. Neither the permitted nor actual SO_2

and NO_x emission reductions from the North Branch Power Station may be used as Emissions Offsets for any other purpose.

ii. The permittee shall retire permanently the 175 TPY of NO_x offsets procured from World Kitchen in Martinsburg, West Virginia approved by the DEQ by letter of 11/17/07. Based on the distance and direction of World Kitchen from the Park, this retirement of emission reduction credits shall result in 17.5 TPY emission offsets toward the TANL requirement.

c. Allowances or Emission Reduction Credits retirements

The permittee shall secure and retire Eligible SO_2 Allowances, Eligible NO_x Allowances, or Emission Reduction Credits in the amount equivalent to 70.2 TPY of Emission Offsets toward the TANL requirement by a combination of the following.

i. Retire Eligible SO_2 Allowances or Eligible NO_x Allowances by transferring them from the Originating Account each year (by making the appropriate designation(s) in the Allowance Tracking System transfer form) into an account administered by the U.S. EPA for the Acid Rain Program to be identified by the DEQ.

(a) To ensure that Eligible SO_2 Allowance or Eligible NO_x Allowance retirements benefit air quality and related values in SNP, any such Allowance that originates from facilities located in an area with an Offset Ratio (from the Attachment A map) higher than 10:1 shall require retirement of an additional ten percent of Eligible SO_2 Allowances or Eligible NO_x Allowances in order to offset one Facility NO_x Emission Ton. For example, Eligible SO_2 Allowances that originate from the 20:1 Offset Ratio area shall be retired at the rate of 22:1; Eligible SO_2 Allowances that originate from the 30:1 Offset Ratio area shall be retired at the rate of 33:1; and Eligible SO_2 Allowances that originate from the 40:1 Offset Ratio area shall be retired at the rate of 44:1 until all of the Allowable Annual NO_x Emissions are offset.

(b) The permittee is prohibited from replenishing or causing to be replenished those retired allowances in the Originating Account of the specific Dominion unit that the allowances originated from, by securing, purchasing or otherwise acquiring allowances from any other accounts and transferring them into that Originating Account. After the date of initial operation, the only allowances that can be placed in that account are those allocated by EPA to that account of a vintage year of and after startup of the equipment listed in Condition 1.

ii. Secure and retire Emission Reduction Credits multiplied by the Offset Ratio of the plant location shown on Attachment A.

iii. The requirements of c.i. and ii. in equation form are:

(Eligible SO_2 or NO_x $\text{Allowance}_{\text{Plant in area of 10:1 Offset Ratio or less}}$/Offset Ratio) +

(Eligible SO_2 or NO_x $\text{Allowance}_{\text{Plant in area greater than 10:1 Offset Ratio}}$/(1.1x Offset Ratio))

$\geq 70.2 - \sum (\text{ERC}_{\text{Plant}}/\text{Offset Ratio})$

d. Procedure and timing.

i. The actions in items Condition 24 b. and c. shall be completed and in effect prior to startup of the equipment listed in Condition 1.

ii. Prior to startup of the equipment listed in Condition 1, the permittee shall provide to the DEQ written documentation from the air pollution control agency that regulates each of the sources identified in 24 b. and c.ii. that the requirements of Condition 24 b. and c.ii. (if that option is selected) have been met and that the emission reductions are recognized by the agency as creditable, permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the DEQ has approved in writing the documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 24 b. and c.ii. (if that option is selected).

iii. The permittee shall submit a report to the DEQ prior to the commencement of operation of the permitted facility that demonstrates that the Allowances have been retired in accordance with Condition 24.c.i. Annual reports demonstrating compliance with the retirement obligations and prohibition on replenishment in Condition 24 c. i. must be submitted to the DEQ within 90 days of the end of each calendar year (i.e. 30 days after the compliance deadline under the Acid Rain Program). These reports shall continue to be required for the life of the facility or until all obligations under this permit condition are satisfied with permanent emission reductions. To the extent the permittee accepts federally enforceable limitations on the Total Annual NO_x Emissions in the future, the permittee will only be required to retire Eligible SO_2 Allowances or ERCs such that the sum of the retired allowances at a plant multiplied by that plant's Offset Ratio is equal to the new Total Annual NO_x Emissions minus 260.5. All reports shall be sent to the DEQ, and

Superintendent
Shenandoah National Park
3655 U.S. Highway 211 East
Luray, VA 22835

At any time, but after at least 30 days notice to the public and the Federal Land Manager, the DEQ, in consultation with the Federal Land Manager, may approve an alternative

mitigation plan proposed by the permittee in lieu of this condition. At a minimum, such a plan shall result in actual sulfur dioxide or nitrogen oxides reductions from an existing stationary source(s) within one of the areas identified in Attachments A and B of at least the Allowable Annual NO_x Emissions multiplied by the corresponding Offset Ratio. Such reductions must be practically enforceable, permanent, and quantifiable, and must be created after January 19, 2010. The reductions must result in the same or greater reduction in impacts to aquatic resources and visibility to the SNP as the retirements of allowances outlined in paragraphs a through c of this condition.
(9 VAC 5-170-160, 9 VAC 5-80-1180, and 9 VAC 5-80-1985 E)

OPERATING/EMISSION LIMITATIONS – EMERGENCY UNITS (EG-1 & FWP-1)

25. **Fuel** – The approved fuel for the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is distillate fuel oil with a maximum sulfur content per shipment of 0.0015 percent by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4207(b), and 40 CFR 80.510(b))

26. **Operating Hours: Emergency Fire Water Pump** - The emergency fire water pump (FWP-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency fire water pump (FWP-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency fire water pump shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

27. **Operating Hours: Emergency Generator** - The emergency generator (EG-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency generator (EG-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency generator shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

28. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

a. The name of the fuel supplier;

b. The date on which the distillate oil was received;

c. The volume of distillate oil delivered in the shipment; and

d. The sulfur content of the distillate oil.

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 25, as applicable. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits. (9 VAC 5-80-1180)

29. **Emergency Generator and Emergency Fire Water Pump Operation** - The operation of the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is limited to emergency situations. Emergency situations include emergency generator use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted and emergency engine use to pump water in the case of fire or flood, etc. The emergency generator (EG-1) and the emergency fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 52 hours per year for each unit.
(9 VAC 5-80-1180 and 40 CFR 60.4211(e) and 40 CFR 60.4219)

30. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	2.0 lbs/hr	0.5 tons/yr
Carbon Monoxide	1.7 lbs/hr	0.4 tons/yr
Volatile Organic Compounds	2.0 lbs/hr	0.5 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 26.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

31. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	23.1 lbs/hr	5.8 tons/yr
Carbon Monoxide	12.6 lbs/hr	3.2 tons/yr
Volatile Organic Compounds	23.1 lbs/hr	5.8 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 27.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

32. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	4.0 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (c), and 40 CFR 60.4211(c))

33. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	6.4 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (b), and 40 CFR 60.4211(c))

34. **Visible Emission Limit** - Visible emissions from the emergency generator (EG-1) and the emergency fire water pump (FWP-1) shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-80-1180)

35. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the emergency generator (EG-1) and the emergency fire water pump (FWP-1) as described in Condition 1 shall be operated in compliance with the requirements outlined in 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-60-90, 9 VAC 5-60-100, 40 CFR 60 Subpart IIII, and 40 CFR 63 Subpart ZZZZ)

OPERATING/EMISSION LIMITATIONS – AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)

36. **Fuel** – The approved fuel for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

37. **Fuel Throughput** – The auxiliary boiler (B-1) shall consume no more than 756.9 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

38. **Fuel Throughput** – The fuel gas heater (GH-1) shall consume no more than 446.8 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

39. **Emission Limits** - Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	4.24 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	14.27 tons/yr
PM-10/PM-2.5	0.44 lbs/hr	1.93 tons/yr
Volatile Organic Compounds	0.47 lbs/hr	2.08 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 37.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

40. **Emission Limits** - Emissions from the operation of the fuel gas heater (GH-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	2.51 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	8.43 tons/yr
PM-10/PM-2.5	0.39 lbs/hr	1.70 tons/yr
Volatile Organic Compounds	0.28 lbs/hr	1.23 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 38.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

41. **Visible Emission Limit** - Visible emissions from both the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

42. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, and 40 CFR 60 Subpart Dc)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

43. **CEMS** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO, in ppmvd corrected to 15 percent O_2, from each combined-cycle unit (T-1, T-2, & T-3). CEMS for NO_x shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the "Monitoring Requirements" in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 16, NO_x data and CO data shall each be reduced to 1-hour block averages. The relative accuracy test audit (RATA) of the NO_x CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-420, 40 CFR 75, 40 CFR 60.13, and 40 CFR 60.4340(b))

44. **CEMS Performance Evaluations** - Performance evaluations of the NO_x and, if applicable, sulfur dioxide continuous monitoring systems shall be conducted in accordance with 40 CFR 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 75, and 40 CFR 60.4345(a))

45. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4345(e), and 40 CFR 60)

46. **Excess Emissions and Monitor Downtime for NO_x - Continuous Monitoring Systems** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 48 are defined as follows:

    a. An excess emission is any unit operating period in which the one-hour average NO_x emission rate exceeds the applicable emission limit in Condition 16; and

    b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee uses this information for compliance purposes.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

47. **Excess Emissions and Monitor Downtime for SO_2 - Continuous Monitoring Systems** Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

    a. An excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

    b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

48. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a continuous emission monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of calendar quarter. These reports shall include, but are not limited to, the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, or malfunctions of the process, the nature and cause of the

malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report; and

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a), and 40 CFR 60.4395)

49. **Excess Emissions for Continuous Monitoring Systems –** For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations;

c. Correction of measured NO_x concentrations to 15 percent O_2 is not allowed; and

d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

RECORDS

50. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. The records shall include, but are not limited to:

    a. Annual throughput of natural gas to each CT (CT-1, CT-2, & CT-3), calculated monthly as the sum of each consecutive 12-month period.

    b. Annual throughput of natural gas to each duct burner (DB1, DB2, & DB3) calculated monthly as the sum of each consecutive 12-month period.

    c. Time, date and duration of each startup, shutdown, and malfunction period for each combined-cycle power generating unit (T-1, T-2, & T-3).

    d. Annual number of startup and shutdown occurrences for each combined-cycle power generating unit (T-1, T-2, & T-3), calculated monthly as the sum of each consecutive 12-month period.

    e. Records to verify sulfur content of pipeline natural gas as required in Condition 15.

    f. Continuous records of heat input for each combined-cycle power generating unit (T-1, T-2, & T-3).

    g. Continuous records of power output from combined-cycle power generating units (T-1, T-2, & T-3) and the steam turbine generator(s).

    h. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 17, 30 and 31, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

    i. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

    j. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period.

    k. Records of time, date, and duration of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing and the operational status of each combined-cycle unit (T-1, T-2, and T-3) during those maintenance checks and readiness testing.

l. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period.

m. All fuel supplier certifications for the emergency units (FWP-1 & EG-1).

n. Records of engine manufacturer data as required by Conditions 32 and 33.

o. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

p. Records for each combined-cycle unit (T-1, T-2, and T-3) showing steady-state vs. non-steady-state operation during a given hour, the ammonia slip monitoring plan, and the ammonia slip monitoring results as required by Condition 21.

q. Scheduled and unscheduled maintenance and operator training.

r. Results of all stack tests, visible emission evaluations, visible emission inspection results, and performance evaluations.

s. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heater (GH-1) calculated monthly as the sum of each consecutive 12-month period.

t. Records of good combustion practices for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as required by Condition 12.

u. Records to verify sulfur content of pipeline natural gas as required in Condition 36.

v. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 39 and 40, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

w. Records related to NO_x offsets as required by Condition 24 d.

x. Records related to the CEMS quality control program as required by Condition 45.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

TESTING

51. **Testing/Monitoring Ports** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendix B).
(9 VAC 5-50-30 F)

52. **Initial Performance Test – Combustion Turbines** - Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for the following pollutants using the specified methods:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile organic compounds (VOC)	40 CFR 60, Appendix A, Method 25A
PM-10 (All particulate matter shall be considered PM-10 and shall include condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19, and 40 CFR 51, Appendix M, Method 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 16. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. CO, VOC and PM-10 emissions shall be determined at each of the operating conditions indicated for each pollutant contained in Condition 16. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.

The permittee shall perform an initial stack test for PM-2.5 in the time frames as required for testing the other pollutants in this condition if a test method for PM-2.5 has received final approval by the USEPA or DEQ at that time. If a test method for PM-2.5 has not received final approval by the USEPA or DEQ at the time initial testing as required in this condition is to be conducted, the permittee shall perform initial stack testing for PM-2.5 within 60 days of final approval of a test method by USEPA or DEQ, or as required by the DEQ. This permit limits for PM-2.5 may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in this condition.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

53. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for oxides of nitrogen (as NO_2) to determine compliance with the limits contained in Condition 16 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_x concentration (in ppm). Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 53.a. above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for NO_x and diluent pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

i. If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent O_2 from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 16 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in Condition 16.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

   i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

   ii. Compliance with the applicable emission limit in Condition 16 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405, and 40 CFR 60.4400)

54. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in ppm). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, and 40 CFR 60.4415)

55. **Initial Performance Test – Auxiliary Boiler and Fuel Gas Heater –** Initial performance tests shall be conducted on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) for NO_x and CO to determine compliance with the emission limits contained in Conditions 39 and 40. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no

later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

56. **Compliance Demonstration – Duct Burners** – The permittee shall determine compliance with the NO_x emission limits in Condition 19 by complying with the NO_x emission limits contained in Condition 16.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 40 CFR 60.4400 (b)(2))

57. **Visible Emissions Evaluation – Combustion Turbines** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined-cycle generating unit stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions for which emissions tests are required for the stack tests contained in Condition 52. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

Should conditions prevent concurrent opacity observations, the DEQ shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

58. **Visible Emissions Evaluation - Auxiliary Boiler and Fuel Gas Heater** - Concurrently with the initial performance tests in Condition 55, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and fuel gas heater (GH-1). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. Each evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler or fuel gas heater, as applicable, will be operated but in no event later than 180 days after start-up of the unit.

Should conditions prevent concurrent opacity observations, the DEQ, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ,

within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit. (9 VAC 5-50-30 and 9 VAC 5-80-1180)

CONTINUING COMPLIANCE DETERMINATION

59. **Annual Performance Test – Combustion Turbines** – Annual performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

    a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

    b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

    c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

    The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4415(a))

60. **Stack Tests** - Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-50-30 G)

61. **Visible Emissions Evaluation – Combustion Turbines** – The permittee shall conduct visible emission inspections on each combined-cycle generating unit (T-1, T-2, & T-3) stack in accordance with the following procedures and frequencies:

    a. At a minimum of once per week, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be conducted for a total of 60 minutes.

    b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per week for that stack.

    c. All visible emission inspections, observations and VEE results shall be recorded.

    (9 VAC 5-50-20)

62. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** – The permittee shall conduct visible emission inspections on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks in accordance with the following procedures and frequencies:

    a. At a minimum of once per month, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10 percent opacity, the VEE shall be conducted for a total of 60 minutes.

    b. All visible emissions inspections shall be performed when the boiler or fuel gas heater (as applicable) is operating.

c. If visible emissions inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per month.

d. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

NOTIFICATIONS

63. **Initial Notifications** - The permittee shall furnish written notification of the following to the DEQ:

a. The actual date on which construction of the electric power generation facility commenced, within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility, within 15 days after such date.

d. The actual date on which construction of the auxiliary boiler commenced, within 30 days after such date.

e. The actual start-up date of the auxiliary boiler, within 15 days after such date.

f. The actual date on which construction of the fuel gas heater commenced, within 30 days after such date.

g. The actual start-up date of the fuel gas heater, within 15 days after such date.

h. The anticipated date of continuous monitoring system performance evaluations, postmarked not less than 30 days prior to such date.

i. The anticipated date of performance tests of the electric power generation facility, postmarked at least 30 days prior to such date.

j. The actual dates on which construction of the emergency generator and emergency fire water pump commenced, within 30 days after such dates.

k. The actual start-up dates of the emergency generator and emergency fire water pump, within 15 days after such dates.

Copies of the written notifications referenced in items a through i above are to be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

64. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction is not commenced within 18 months from the date of this permit.

    b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time. This provision does not apply to the period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date

    DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.
    (9 VAC 5-80-1210 and 9 VAC 5-80-1985)

65. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit;

    d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1210 F and 9 VAC 5-80-1985)

66. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

67. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

68. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J)

69. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the DEQ, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the DEQ, in writing.
(9 VAC 5-20-180 C)

70. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

71. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the DEQ, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240 and 9 VAC 5-80-1975)

72. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-170-160)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-60-300, *et. seq.* Neither their inclusion in this Prevention of Significant Deterioration Permit nor any resulting public comment period make these terms federally enforceable.

73. **Emission Limits** - Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS #	Hourly Limit	Annual Limit
Acrolein	107-02-8	0.0406 lbs/hr	0.176 tons/yr
Formaldehyde	50-00-0	1.48 lbs/hr	6.34 tons/yr
Cadmium	7440-43-9	0.0115 lbs/hr	0.00551 tons/yr
Chromium	7440-47-3	0.0146 lbs/hr	0.00702 tons/yr
Nickel	7440-02-0	0.0219 lbs/hr	0.0105 tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320, 9 VAC 5-80-1180, and 9 VAC 5-80-1625 G)

74. **Emission Limits** – The permittee shall determine compliance with the toxic pollutants emission limits in Condition 73 as follows:

a. To calculate hourly toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i\right)\left(\frac{100 - CE}{100}\right)$$

..... Equation 1

Where:

E_t = Emission rate of toxic compound (t) (lbs/hr)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

b. To calculate annual toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i T_i\right)\left(\frac{100 - CE}{100}\right)\left(\frac{1ton}{2000lb}\right)$$

..... Equation 2

Where:

E_t = Emission rate of toxic compound (t) (tons/year)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

T_i = Hours of operation for each unit (i) utilized during the time period (hours)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1625 G)

75. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to:

a. Total hours that each unit operates on a monthly basis.

b. Average hourly, monthly and annual emissions (in pounds and tons) of each toxic compound listed in Condition 73. Toxic compound emissions shall be calculated as shown in Condition 74. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.

These records shall be available for inspection by the DEQ and shall be current for at least the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-50-50, and 9 VAC 5-80-1625 G)

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

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* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

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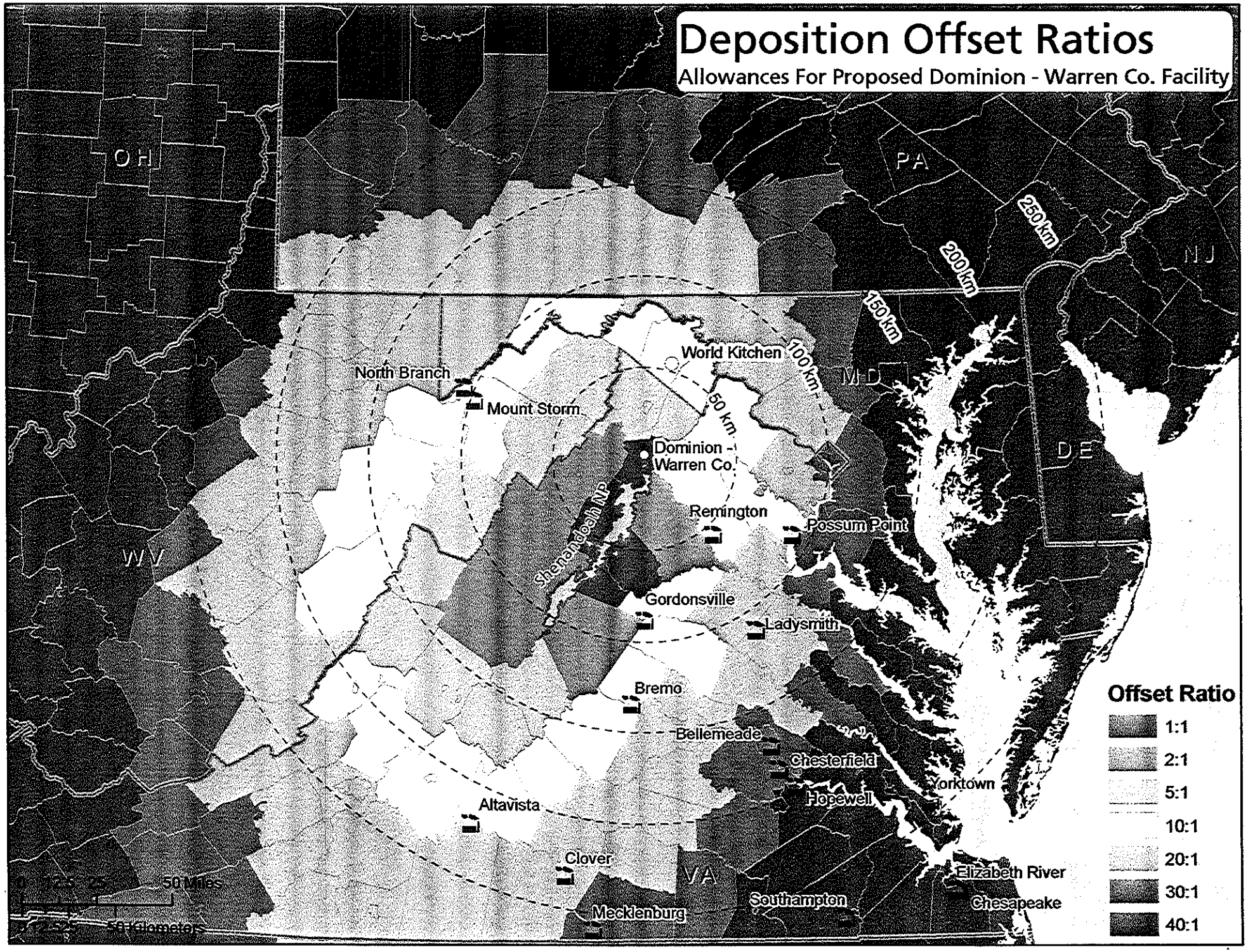
* Not applicable to visible emission evaluations.


Deposition Offset Ratios
Allowances For Proposed Dominion - Warren Co. Facility
OH
PA
NJ
MD
DE
WV
VA
250 km
200 km
150 km
100 km
50 km
World Kitchen
North Branch
Mount Storm
Dominion - Warren Co.
Shenandoah NP
Remington
Possum Point
Gordonsville
Ladysmith
Bremo
Bellemeade
Chesterfield
Hopewell
Yorktown
Altavista
Clover
Mecklenburg
Southampton
Elizabeth River
Chesapeake
50 Miles
50 Kilometers
Offset Ratio
1:1
2:1
5:1
10:1
20:1
30:1
40:1

Attachment B: List of Geographic Locations From Which Allowances May Be Obtained

1:1 Locations:

Virginia Counties:	Warren, Page, Madison, and Greene

2:1 Locations:

Virginia Counties:	Shenandoah, Rockingham, Augusta, Albemarle, Culpeper, and Rappahannock
Virginia Cities:	Harrisonburg, Staunton, Waynesboro, and Charlottesville

5:1 Locations:

Virginia Counties:	Frederick, Highland, Bath, Rockbridge, Amherst, and Nelson
Virginia Cities:	Winchester, Lexington, and Buena Vista
West Virginia Counties:	Hampshire, Hardy, and Pendleton

10:1 Locations:

Virginia Counties:	Loudoun, Prince William, Fauquier, Orange, Louisa, Fluvanna, Buckingham, Appomattox, Campbell, Bedford, Botetourt, and Alleghany
Virginia Cities:	Lynchburg, Bedford, and Covington
West Virginia Counties:	Jefferson, Berkeley, Morgan, Mineral, Grant, Tucker, Randolph, and Pocahontas
Maryland Counties:	Allegany

20:1 Locations:

Virginia Counties:	Fairfax, Stafford, Spotsylvania, Caroline, Hanover, Goochland, Powhatan, Amelia, Cumberland, Prince Edward, Nottoway, Lunenburg, Charlotte, Halifax, Pittsylvania, Henry, Patrick, Floyd, Franklin, Montgomery, Roanoke, Craig, and Giles
Virginia Cities:	Fairfax, Manassas Park, Manassas, Fredericksburg, Danville, Martinsville, Roanoke, and Salem
West Virginia Counties:	Monroe, Greenbrier, Nicholas, Webster, Braxton, Lewis, Upshur, Barbour, Harrison, Marion, Taylor, Preston, and Monongalia
Maryland Counties:	Garrett, Washington, Frederick, and Montgomery

Pennsylvania Counties: Greene, Fayette, Somerset, Bedford, Fulton, and Franklin

30:1 Locations:

Virginia Counties: King George, Essex, King William, Henrico, Chesterfield, Dinwiddie, Brunswick, Mecklenburg, Carroll, Grayson, Wythe, Pulaski, and Bland

Virginia Cities: Richmond, Galax, and Radford

West Virginia Counties: Mercer, Summers, Raleigh, Fayette, Clay, Gilmer, and Doddridge

Pennsylvania Counties: Washington, Allegheny, Westmoreland, Armstrong, Indiana, Cambria, Blair, Cumberland, and Adams

Maryland Counties: Carroll, Howard, Prince George's, and Charles

40:1 Locations:

All other jurisdictions within the boundaries of Virginia, North Carolina, Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania, New Jersey, Delaware, and Maryland

Competitive Power Ventures, Inc.

RECEIVED
FEB 03 2014
DEQ SWRO

January 31, 2014

Virginia Department of Environmental Quality
Attention: Rob Feagins, Air Permit Manager
Southwest Regional Office
355-A Deadmore Street
Abingdon, Virginia 24210

RE: CPV Smyth Generation Company, LLC Prevention of Significant Deterioration Air Permit Application

Dear Mr. Feagins,

Please find enclosed four copies of CPV Smyth Generation Company, LLC's Prevention of Significant Deterioration Air Permit Application.

Per our previous discussions with you and Michael Kiss, this application includes the engineering portions of our PSD air permit application, including: the project description; potential emissions calculations and applicability determination; a review of state and federal air quality regulations to which the project is subject; Best Available Control Technology analysis; and, the VDEQ application forms, emissions calculation backup, and detailed equipment and vendor data. The air quality modeling analyses will be submitted separately, following completion of the collection of on-site meteorological data, as previously discussed.

Also enclosed for your information with this transmittal is our permit fee transmittal to the Virginia Department of Environmental Quality sent in parallel with this application.

We look forward to working with the Virginia Department of Environmental Quality on the review of CPV Smyth Generating Company, LLC's application.

Should you have any questions or in need of any clarifications, please do not hesitate to contact me at your convenience.

Sincerely,

Gener G. Gotiangco, P.E.
ggotiangco@cpv.com
240-723-2307

cc: M. Kiss, VA DEQ (via email)
F. Sellars, Tetra Tech (via e-mail)
R. Burke, Competitive Power Ventures, Inc. (via e-mail)

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RECEIVED
FEB 03 2014
DEQ SWRO

PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION

CPV Smyth Generation Company, LLC

Atkins, Virginia

Prepared on behalf of:

CPV

CPV Smyth Generation Company, LLC
8403 Colesville Road, Suite 915
Silver Spring, MD 20910

For Submittal to:

Virginia Department of Environmental Quality
Southwest Regional Office
355 Deadmore St.
Abingdon, VA 24212

Prepared by:

TETRA TECH

Tetra Tech
160 Federal Street, 3rd Floor
Boston, MA 02110

January 2014

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APPENDICES

Appendix A VDEQ Air Permit Application Forms
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Appendix C Equipment Specifications and Vendor Performance Data

ACRONYMS AND ABBREVIATIONS

ACC	air cooled condenser
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
BHP	brake horsepower
Btu/kW-hr	British thermal unit per kilowatt-hour
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CEMS	continuous emissions monitoring system
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPV Smyth	CPV Smyth Generation Company, LLC
CSAPR	Cross State Air Pollution Rule
CTG	combustion turbine generator
DAHS	data acquisition handling system
DLN	dry-low NO_x
°F	degrees Fahrenheit
GHG	greenhouse gases
g/kW-hr	grams per kilowatt-hour
gr/100 scf	grains per 100 standard cubic feet
H_2SO_4	sulfuric acid
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HFCs	hydrofluorocarbons
HHV	higher heating value
HRSG	heat recovery steam generator
kW	kilowatt
LAER	Lowest Achievable Emission Rate
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt-hour
lb/hr	pounds per hour
lbs	pounds
LLO	Low Load Operation
LNB	low NO_x burners
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MW	megawatt

ACRONYMS AND ABBREVIATIONS (Continued)

MWh	megawatt-hour
$\mu g/m^3$	microgram per cubic meter
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NH_3	ammonia
N_2O	nitrous oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NNSR	Nonattainment New Source Review
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
O_3	ozone
Pb	lead
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 micrometers or less
PM_{10}	particulate matter with an aerodynamic diameter of 10 micrometers or less
ppm	parts per million
ppmvd @15%	parts per million volume dry at 15% oxygen
PSD	Prevention of Significant Deterioration
RBLC	RACT\BACT\LAER Clearinghouse
SAAC	Significant Ambient Air Concentration
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SIP	State Implementation Plan
SO_2	sulfur dioxide
STG	steam turbine generator
SU/SD	start-up/shutdown operation
SWRO	Southwest Regional Office
TLV®	Threshold Limit Value
tpy	tons per year
ULSD	ultra low sulfur diesel
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VAAQS	Virginia Ambient Air Quality Standards
VAC	Virginia Administrative Code
VDEQ	Virginia Department of Environmental Quality
VOC	volatile organic compound

1.0 INTRODUCTION

CPV Smyth Generation Company, LLC (CPV Smyth) proposes to construct and operate a nominal 700-megawatt (MW) natural gas-fired, combined-cycle generating facility in Atkins, Virginia. Construction of the CPV Smyth Generation Company (the Project) is scheduled to begin in early 2015 with commencement of commercial operation by mid-2017. The proposed project location is a greenfield site with no commercial history.

The proposed Project will include two natural gas-fired combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs) and one steam turbine generator (STG). The Project will be configured as a "2 on 1" power block with steam from the two HRSGs feeding the single STG. The balance of the Project will include an auxiliary boiler, emergency generator engine, emergency fire pump engine, aqueous ammonia (NH_3) storage tank, and an air cooled condenser (ACC).

The Project will have potential emissions above the Prevention of Significant Deterioration (PSD) major source threshold for nitrogen oxides (NO_x), carbon monoxide (CO) and greenhouse gases (GHGs). As major source for NO_x emissions, the Project will also be considered major for ozone. Potential emissions of all size fractions of particulate matter ($PM/PM_{10}/PM_{2.5}$), volatile organic compounds (VOCs) and sulfuric acid mist (H_2SO_4) will be above their respective PSD significant emissions threshold. Therefore, the Project will be subject to PSD permitting for NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOC, H_2SO_4, and GHGs. CPV Smyth is applying for a PSD permit from the Virginia Department of Environmental Quality (VDEQ) for the Project. The PSD permit is required under 9 Virginia Administrative Code (VAC) 5-80, Part II, Article 8 (9 VAC 5-80-1600 et seq.). This document, along with the accompanying VDEQ forms and other appended materials, is the PSD application for the Project. The Project will not be subject to Nonattainment New Source Review (NNSR) because the site is located in Smyth County, which is designated as unclassified or attainment for all criteria pollutants. This application addresses the permitting requirements specified by the VDEQ under 9 VAC 5, Chapters 80 and 85 as well as those contained in Title 40 of the Code of Federal Regulations (CFR) Part 52.21 (40 CFR 52.21).

Emissions of sulfur dioxide (SO_2) will be below its PSD significant emissions rate threshold but above the VDEQ de minimis permitting thresholds based on uncontrolled potential emissions as specified in 9 VAC 5-80-1105. As a result, SO_2 emissions will trigger VDEQ Best Available Control Technology (BACT) requirements under 9 VAC 5-80 Part II Article 6 and this application also addresses the VDEQ permitting requirements for these pollutants. For informational purposes and completeness, emissions have been quantified and BACT analyses have been completed for NH_3 emissions from the CTGs due to its use as the reagent in the selective catalytic reduction (SCR) systems proposed in the HRSGs of these units.

To facilitate VDEQ's review of this document, individuals familiar with the Project are identified below. The VDEQ should contact these individuals if additional information or clarification is required during the review process. These contacts include the primary contact for the project developer and consultant who were responsible for the preparation of this application.

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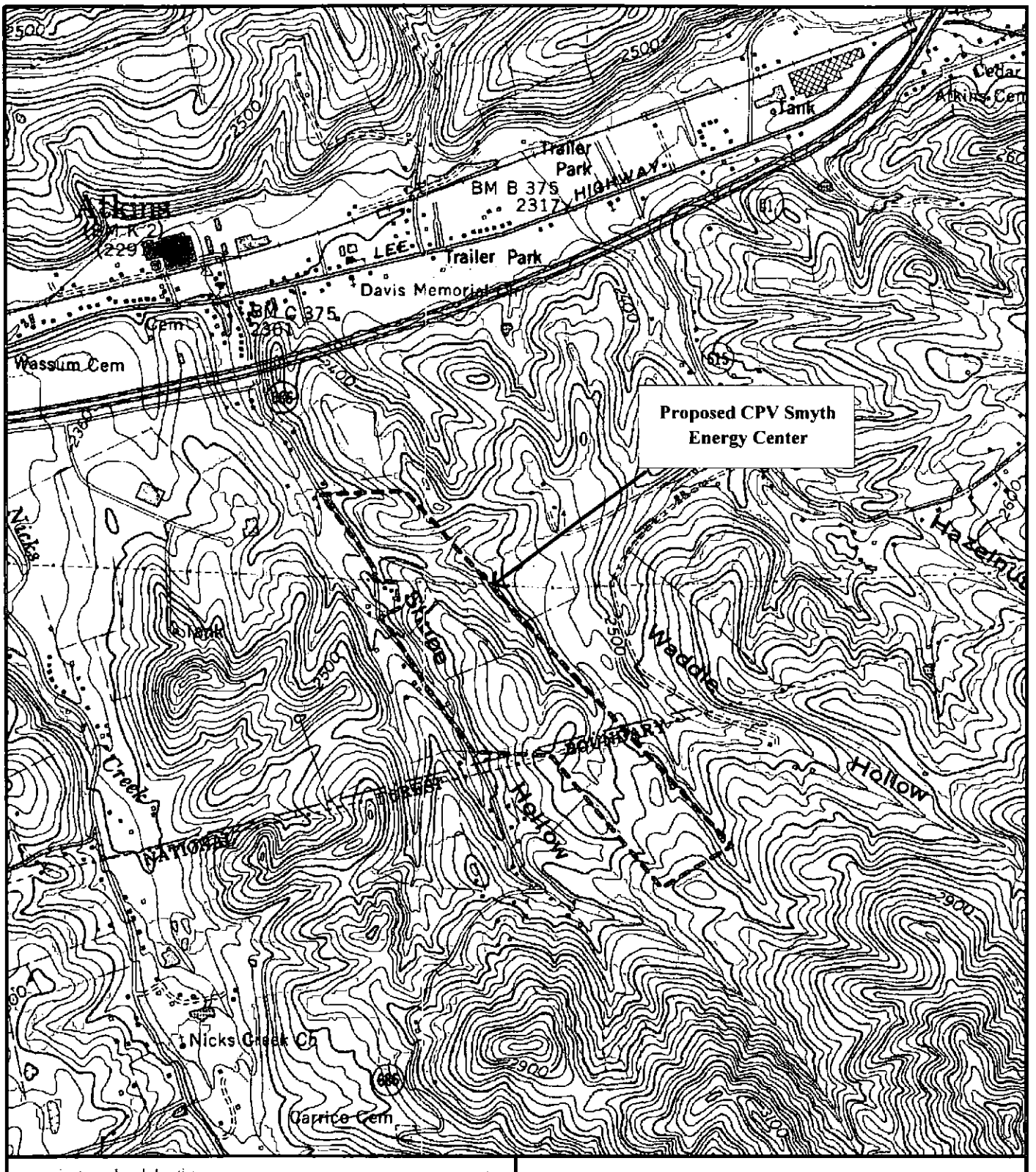
This application consists of the following five sections in addition to this Introduction:

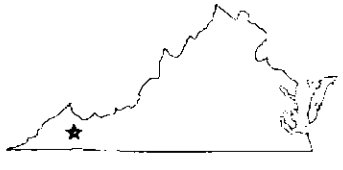
- Section 2 provides a project description, including information regarding the plant's location and equipment design information;
- Section 3 provides a description of potential emissions and the basis of calculation;
- Section 4 provides a review of state and federal air quality regulations applicable or potentially applicable to the Project;
- Section 5 provides the BACT analyses;
- Appendices A through C provide the VDEQ Forms, emission calculations, and detailed equipment and vendor data.

Provided in Figure 1-1 is a General Location Map showing the location of the Project and nearby area.

Figure 1-1 General Location Map



approximate quadrangle location



0 0.25 0.5
kilometers

N

Based on USGS 1:24,000 Quadrangle map for Atkins, Virginia, 1991.

CPV Smyth Generation Company, LLC

Figure 1-1
General Location

2.0 PROJECT DESCRIPTION

2.1 Site Location

The proposed Project will be constructed on a 108-acre parcel at a greenfield location in Atkins, VA. The site is located in east-central Smyth County, approximately 4 miles east-northeast of Marion, VA and approximately 0.5 miles south of Interstate 81. The site is in a rural valley at a 2,500 foot above mean sea level elevation with higher elevation mountains running generally in a southwest to northeast direction and located approximately 2 to 3 miles north and south of the property.

2.2 Project Description

The proposed nominal 700 MW[1] combined-cycle natural gas-fired facility will be configured as two operating units. The power plant will be configured in a "2 on 1" power block configuration with steam from the two HRSGs feeding the single STG. The HRSGs will be equipped with duct burners (supplementary firing) to provide additional generating capacity during periods of peak demand. The facility is designed to run as a base load plant with both combustion turbines operating concurrently but the facility will have the capability of operating with a single combustion turbine.

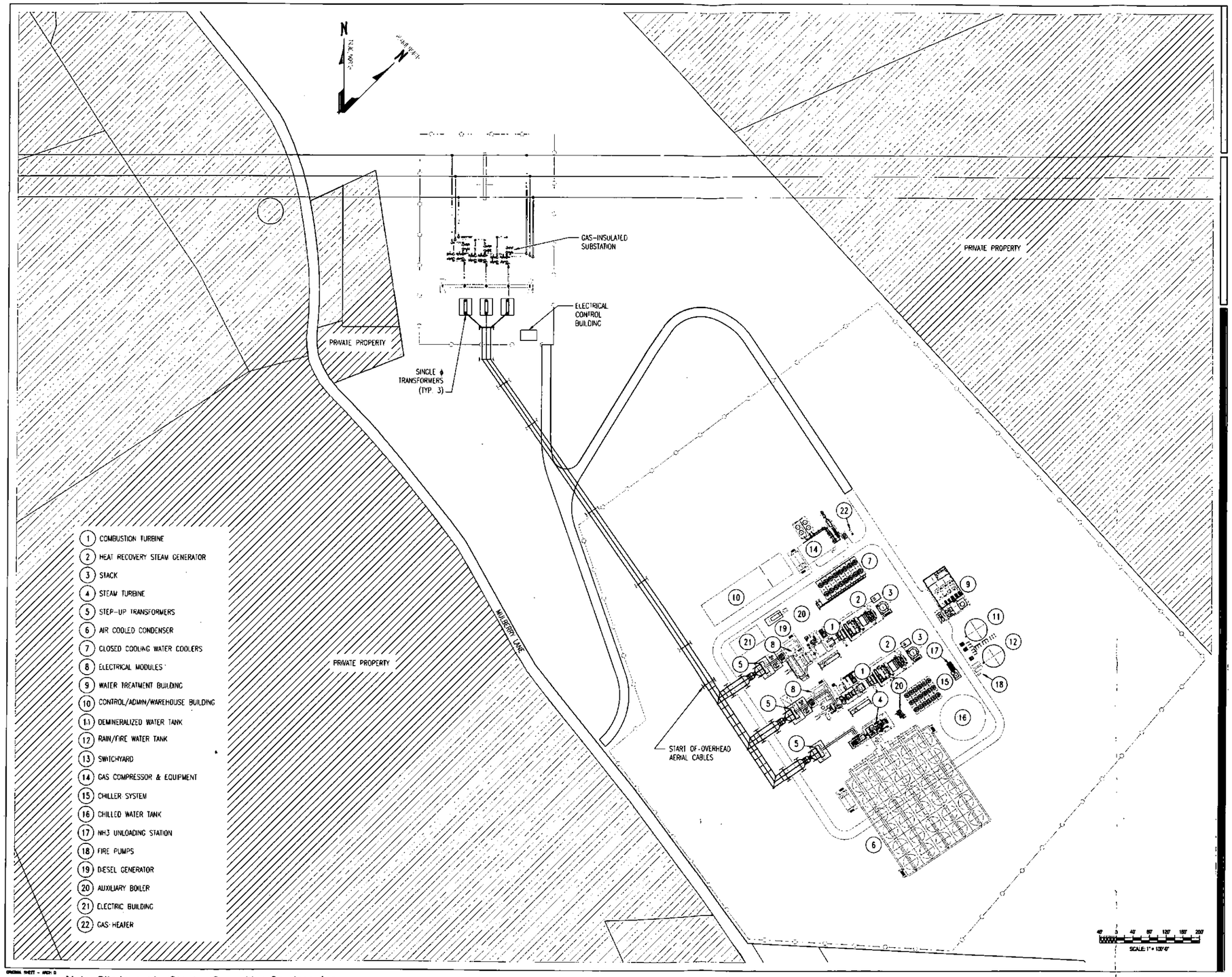
The Project will include a variety of power plant equipment including: two natural gas-fired CTGs; one STG; two HRSGs with SCR and oxidation catalyst emissions control equipment; generator step-up transformers; an electrical switchyard; an NH_3 storage tank; water tanks; and an ACC. In addition, the Project will include other buildings for administrative and operating staff; warehousing of parts and consumables; and maintenance shops and equipment servicing. An overview of equipment arrangement on the site is provided as Figure 2-1.

The first stage in the generation process of a combined-cycle power plant is the operation of the CTGs. Thermal energy, in the form of hot exhaust gas, is produced in the CTGs through the combustion of natural gas. The hot exhaust gases are then converted into mechanical energy by a turbine that drives a generator. The exhaust gas temperature exiting the gas turbine is in excess of 1,000 degrees Fahrenheit (°F) and still has remaining a significant amount of recoverable heat energy. This heat energy is recovered in the HRSG by generating steam that is sent to a STG to generate additional electrical energy. The generation of electricity using both a gas turbine and steam turbine defines the combined cycle, which the most efficient form of electrical generation available. The efficiency of the facility is further enhanced by using reheat systems as well as waste energy to heat feedwater in the HRSG by an additional economizer loop and also for fuel preheating. Once the steam leaves the steam turbine, it is condensed back into water using an ACC and this condensed water is returned to the HRSGs to minimize water use. Additional steam, and consequently additional electricity, may be generated when required by the use of supplemental natural gas-fired burners (duct burners) within the HRSGs.

Each of the two CTGs that will be used by the Project is an Alstom GT24 with a nominal generating capacity of 234 MW (at -10°F ambient conditions). The CTGs will be equipped with inlet air cooling via fogging and evaporative cooling or chillers. The single steam turbine will provide up to an additional 228 MW without duct firing (at -10°F ambient conditions) and 312 MW with duct firing in both HRSGs (90°F ambient conditions, at which the gas turbines produce 201 MW utilizing the chillers option installed and in operation).

[1] Based on 90°F ambient temperature, 50% relative humidity, and duct firing.

Figure 2-1 Equipment Arrangement Overview



Note: Site layout by Stantec Consulting Services, Inc.

Figure 2-1
CPV Smyth Generation Company, LLC
Equipment Arrangement

Pollutant emissions from the Project will be minimized through the use of natural gas as the sole fuel to be fired in the CTGs and duct burners. Each HRSG will be equipped with SCR and an oxidation catalyst to reduce emissions of NO_x, and CO and VOC, respectively. The SCR system will utilize 19% aqueous NH_3 as the reagent in the SCR systems. Continuous emissions monitoring systems (CEMS) will continuously sample, analyze, and record exhaust gas concentrations of NO_x, CO and NH_3 from each of the two HRSG exhaust flues. The CEMS will be installed and operated in accordance with United States Environmental Protection Agency (USEPA) and VDEQ requirements and will generate emissions data reports that will be consistent with anticipated permit requirements and send alarm signals to plant supervisory and control systems when emissions approach or exceed permitted limits.

Ancillary equipment at the proposed Project will include three additional fuel combustion emission units:

- A 93 million British thermal unit per hour (MMBtu/hr) natural gas-fired auxiliary boiler equipped with ultra low-NOx burners;
- A 1,500 kilowatt (kW) (standby rating) emergency generator firing 15 parts per million (ppm) ultra low sulfur distillate (ULSD) oil; and
- A 315 brake horsepower (BHP) emergency fire pump engine firing ULSD oil.

To support the SCR systems, a 20,000 gallon above-ground storage tank will contain 19% aqueous NH_3. The tank will be located within a concrete containment structure (dike) along with the ammonia transfer pumps, valves and piping.

The Project will interconnect with the 765 kilovolt transmission line that crosses the northern portion of the site via a new switchyard. Natural gas will be delivered from the existing gas pipeline located approximately 1.5 miles to the north of the site. A pipeline lateral will be installed to bring the gas from the existing pipeline to the site.

3.0 AIR EMISSIONS

This section presents short-term and long-term potential emissions from each emission source for the Project. Project emissions will be minimized through the application of BACT controls. CPV Smyth proposes to use dry low-NO_x combustion and SCR to minimize NO_x emissions from the combustion turbines. Combustion controls and an oxidation catalyst will be used to minimize CO and VOC emissions from the turbines. SO_2 and $PM/PM_{10}/PM_{2.5}$ will be controlled through the use of natural gas as the sole fuel for the turbines, duct burners and auxiliary boiler. ULSD oil will be used for the emergency generator and fire pump engines. Section 5 of this application contains control technology analysis to demonstrate that these controls meet BACT requirements. Appendix B of this application contains detailed emission calculations and Appendix C contains equipment specifications and vendor performance data for the proposed emission sources.

3.1 Emission Sources

The emission sources for the Project will include:

- One combined cycle power generation unit, consisting of two combustion turbines (Alstom GT24) serving two associated HRSG's with duct burners and one common STG. The combined cycle power generation units will be equipped with: inlet air cooling via high fogging and evaporative cooling or chillers; SCR for NO_x control; and an oxidation catalyst for control of CO and VOC;
- One natural gas fired auxiliary boiler rated at 93 MMBtu/hr, equipped with ultra low-NOx burners (Cleaver Brooks "Nebraska" D-type boiler or equivalent);
- One emergency generator rated at 1,500 kW (standby rating), firing ULSD oil (Caterpillar 3512C or equivalent);
- One fire pump engine rated at approximately 315 BHP, firing ULSD oil (Clarke JU6H-UFAD98 or equivalent); and

The following equipment will not have any potential air emissions under normal operation:

- ACC for condenser cooling; and
- One 20,000 gallon above ground aqueous NH_3 storage tank.

The facility will also include miscellaneous insignificant sources such as small ULSD and lubricant storage tanks, which will have insignificant emissions.

3.2 Short-Term Emissions

3.2.1 Combustion Turbine and HRSG Units

Short-term potential emission rates for each combined cycle unit, including the combustion turbine and associated duct burner, are presented in Table 3-1. The rates shown are based on 100% load operation at -10°F with duct burner firing, and represent the worst case operating scenario. Potential emission rates are presented in: parts per million by volume, dry basis (ppmvd), corrected to 15% oxygen (O_2); pounds per million British thermal units (lb/MMBtu) on a high heating value (HHV) basis; and pounds per hour

(lb/hr). SO_2 emissions are based on a maximum natural gas sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf).

Table 3-1: Short-Term Emission Rates for Turbine and HRSG Units (per unit)

Pollutant	ppmvd at 15% O_2	lb/MMBtu	lb/hr[1]
NO_x	2.0	0.0074	19.6
CO	2.0	0.0045	11.9
VOC, unfired	1.0	0.0013	2.9
VOC, duct-fired	2.0	0.0026	6.8
SO_2	0.3	0.0014	3.8
PM/ PM_{10}/ $PM_{2.5}$	N/A	N/A	12.9

[1] Includes duct firing except VOC, unfired

3.2.2 Ancillary Equipment

Short-term potential emission rates for the auxiliary boiler, the emergency generator, and the fire pump engine are presented in Table 3-2. Potential emission rates are presented in lb/MMBtu or grams per kilowatt-hour (g/kWh) as appropriate, and in lb/hr.

Table 3-2: Short-Term Emission Rates for Ancillary Equipment

Pollutant	Auxiliary Boiler		Emergency Generator		Fire Pump	
	lb/MMBtu	lb/hr	g/kWh	lb/hr	g/kWh	lb/hr
NO_x	0.011	1.01	6.4	21.16	4.0	2.07
CO	0.037	3.42	3.5	11.57	3.5	1.91
VOC	0.005	0.47	1.3	4.30	1.3	0.26
SO_2	0.0014	0.13	0.0015 lb/MMBtu	0.02	0.0015 lb/MMBtu	0.003
PM/ PM_{10}/ $PM_{2.5}$	0.005	0.46	0.2	0.66	0.2	0.10

3.3 Annual Emissions

The proposed potential annual emissions from the Project are summarized in Table 3-3. Potential annual emissions are based on the following operating assumptions:

- For the combustion turbines, 5,760 hours at 100% load, operating at 59°F, with no duct burner firing, and 3,000 hours at 100% load, operating at -10°F, with duct burner firing;
- For the auxiliary boiler, 4,000 hours at 100% load;
- For the emergency generator and fire pump engines, 500 hours each at maximum rated power;

Table 3-3: Facility-Wide Annual Potential Emissions

Pollutant	Unit 1 (CTG & HRSG) (tpy)	Unit 2 (CTG & HRSG) (tpy)	Auxiliary Boiler (tpy)	Emergency Generator (tpy)	Fire Pump (tpy)	Facility Total (tpy)
NO_x	74.7	74.7	2.02	5.29	0.52	157.2
CO	47.7	47.7	6.83	2.89	0.45	105.6
VOC	22.1	22.1	0.94	1.07	0.06	46.3
SO_2	13.2	13.2	0.26	0.005	0.001	26.6
$PM/PM_{10}/PM_{2.5}$	39.5	39.5	0.92	0.17	0.03	80.1
Carbon dioxide equivalent (CO_2e)	1,156,440	1,156,440	21,627	592	90	2,335,189
H_2SO_4	8.6	8.6	0.02	0.0004	0.0001	17.3
Lead (Pb)	4.5E-03	4.5E-03	9.1E-05	2.8E-06	4.2E-07	0.009
NH_3	65.2	65.2	N/A	N/A	N/A	130.3
Total HAPS	4.2	4.2	0.35	0.02	0.004	8.7

The combustion turbines have higher mass emissions of NO_x, CO and VOC during start-up and shutdown than during full-load operation. The impact of increased emissions during start-up and shutdown were evaluated to determine the total potential emissions for the Project, including startup and shutdown operation. Start-ups for combined-cycle systems are generally classified as cold, warm, and hot depending on the length of time the unit has been off-line prior to start-up. The length of start-ups will vary with the type of start-up and plant equipment temperatures.

The maximum number of starts per year per turbine was determined based upon turbine vendor recommendations and projected operation in the competitive power marketplace. Low Load Operation (LLO) is unique to Alstom's gas turbine featuring sequential combustion technology. For customers operating in markets where daily stop/starts and/or parking at low load are required, the LLO feature offers additional flexibility. LLO allows operators to park the entire plant down to 10% combined cycle power plant load with both CTGs and the STG in operation. Due to the sequential combustion technology, the emissions at the LLO point stay at BACT level emission rates. Compared to a 40-50% plant minimum load, which is the current industry standard, the LLO feature provides unique spinning reserve capability for the KA24-2 turbine, without a risk of start failure and without cyclic lifetime consumption of the gas turbine. The LLO is achieved by switching off the second combustor, while the first combustor operates in its optimal point (thus producing base-load like emissions). For emissions purposes, switching off the second combustor is considered "an event" similar to a startup or shutdown in that it has a defined period of transitional non-compliance before stabilizing at compliance levels. These transitional periods occur in both directions as the unit unloads to LLO and as the unit reloads to the normal minimum emission compliance point. This operating characteristic allows for cycling down of the turbine during periods of low demand rather than shutting the unit down. As a result, the number of starts and stops for the Alstom GT24 turbine could be greatly reduced, which would result in a reduction in annual emissions for the Project.

The increase in emissions per type of start was quantified using emissions and operating data provided by Alstom. The increase in emissions for each type of start was then compared to the reduction in emissions associated with the minimum turbine downtime per type of startup/shutdown event. Any increase in start-up/shutdown (SU/SD) emissions quantified for each type of start was added to the potential emissions for continuous full load operation for 8,760 hours per year. This potential to emit approach represents the worst-case maximum potential to emit for the Project. The potential annual emissions of NO_x, CO and VOC in Table 3-3 include the higher emissions from either a conservative number of startup and shutdown cycles (250 hot starts, 50 cold starts, 300 shutdowns) per unit or 250 transition events per unit. Since emissions during cold and warm starts are self-correcting (i.e., SU/SD emissions are equal to or lower than full load steady state emissions when downtime is considered), it was conservatively assumed that the majority of starts would be hot starts. Table 3-4 provides a summary of SU/SD net emissions increases for the CTGs as compared to steady state operation. SU/SD emissions calculations are provided in detail in Appendix B.

Table 3-4: Summary of Startup/Shutdown Net Emissions Increase (lb/hr)

Pollutant	Cold Start	Warm Start	Hot Start	Shutdown	Transition to/from LLO
NO_x	N/A	N/A	4.07	0.05	N/A
CO	N/A	N/A	4.40	0.41	1.17
VOC	N/A	N/A	4.08	0.65	2.23

As summarized above, there is a net increase in average hourly emissions during hot starts, shutdown and transition events. For NO_x, CO and VOC emissions, a combined hot start and shutdown event provides higher hourly emissions than a transition event to and from LLO event so these were used in adjusting the plant's annual potential to emit.

3.4 Hazardous Air Pollutant and Virginia Air Toxics Emissions

Potential annual hazardous air pollutant (HAP) emissions are presented in Table 3-5 for the Project. HAP is defined in Section 112(b) under the Clean Air Act (CAA) Amendments of 1990; and for Virginia "air toxics", as modified. The regulation of HAP emissions are administered by the VDEQ under 9 VAC 5 Chapter 60. Section 4 of this application provides a discussion of the applicability of 9 VAC 5 Chapter 60 to the Project. Total HAP emissions from the Project are 8.7 tpy; detailed HAP emissions calculations are provided in Appendix B.

Table 3-5: Summary of Potential HAP Emissions

HAP	Potential Annual Emissions (tpy)					TOTALS
	CTGs	HRSGs	Auxiliary Boiler	Em. Generator	Fire Pump	
Organic Compounds						
Acetaldehyde	6.90E-01	5.18E-02		9.11E-05	4.22E-04	7.42E-01
Acrolein	1.10E-01	8.28E-03		2.85E-05	5.09E-05	1.19E-01
Benzene	2.07E-01	1.55E-02	3.88E-04	2.81E-03	5.13E-04	2.26E-01
1,3-Butadiene	7.41E-03	5.56E-04			2.15E-05	7.99E-03
Dichlorobenzene			2.22E-04			2.22E-04
Ethylbenzene	5.52E-01	4.14E-02				5.93E-01

Table 3-5: Summary of Potential HAP Emissions

HAP	Potential Annual Emissions (tpy)					TOTALS
	CTGs	HRSGs	Auxiliary Boiler	Em. Generator	Fire Pump	
Formaldehyde	1.90E+00	4.53E-01	1.37E-02	2.85E-04	6.49E-04	2.36E+00
Hexane			3.33E-01			3.33E-01
Propylene oxide	5.00E-01	3.75E-02		1.39E-02	1.96E-03	5.53E-01
Toluene	2.24E+00	1.68E-01	6.10E-04	1.02E-03	2.25E-04	2.41E+00
Xylene	1.10E+00	8.28E-02		6.98E-04	1.57E-04	1.19E+00
PAHs						
Acenaphthene			3.33E-07	1.69E-05	7.81E-07	1.80E-05
Acenaphthylene			4.44E-07	3.34E-05	2.78E-05	6.16E-05
Anthracene			3.33E-07	4.45E-06	1.03E-06	5.81E-06
Benzo(a)anthracene			3.33E-07	2.25E-06	9.24E-07	3.51E-06
Benzo(a)pyrene			2.22E-07	9.29E-07	1.03E-07	1.25E-06
Benzo(b)fluoranthene			3.33E-07	4.01E-06	5.45E-08	4.40E-06
Benzo(g,h,i)perylene			2.22E-07	2.01E-06	2.69E-07	2.50E-06
Benzo(k)fluoranthene			3.33E-07	7.88E-07	8.53E-08	1.21E-06
Chrysene			3.33E-07	5.53E-06	1.94E-07	6.06E-06
Dibenz(a,h)anthracene			2.22E-07	1.25E-06	3.21E-07	1.79E-06
7,12-Dimethylbenz(a) anthracene			2.96E-06			2.96E-06
Fluoranthene			5.36E-07	1.46E-05	4.19E-06	1.93E-05
Fluorene			4.99E-07	4.63E-05	1.61E-05	6.28E-05
Indeno(1,2,3-cd)pyrene			3.33E-07	1.50E-06	2.06E-07	2.04E-06
3-Methylchloranthrene			3.33E-07			3.33E-07
2-Methylnaphthalene			4.44E-06			4.44E-06
Naphthalene	2.24E-02	1.68E-03	1.15E-04	4.70E-04	4.66E-05	2.47E-02
Phenanthrene			3.14E-06	1.48E-04	1.62E-05	1.67E-04
Pyrene			9.06E-07	1.34E-05	2.63E-06	1.69E-05
TOTAL PAH	3.79E-02	2.85E-03	1.26E-04	7.67E-04	9.24E-05	4.18E-02
Metals						
Arsenic	3.45E-03	2.59E-04	3.70E-05	1.67E-07	2.54E-08	3.74E-03
Beryllium	2.07E-04	1.55E-05	2.22E-06			2.25E-04
Cadmium	1.90E-02	1.42E-03	2.03E-04	1.85E-08	2.82E-09	2.06E-02
Chromium	2.41E-02	1.81E-03	2.59E-04	4.48E-05	6.82E-06	2.63E-02
Chromium VI	4.31E-03	3.23E-04	4.62E-05	8.10E-06	1.23E-06	4.69E-03
Cobalt	1.41E-03	1.06E-04	1.52E-05			1.53E-03
Lead	8.45E-03	6.34E-04	9.06E-05	2.78E-06	4.23E-07	9.18E-03
Manganese	6.38E-03	4.79E-04	6.84E-05	1.02E-06	1.55E-07	6.93E-03
Mercury	4.31E-03	3.23E-04	4.62E-05	3.72E-08	5.67E-09	4.68E-03
Nickel	3.62E-02	2.72E-03	3.88E-04	5.35E-06	8.14E-07	3.93E-02
Selenium	4.14E-04	3.11E-05	4.44E-06	9.26E-07	1.41E-07	4.50E-04
Max. Single HAP						**2.4**
Total All HAPs	**7.5E+00**	**8.7E-01**	**3.5E-01**	**2.0E-02**	**4.2E-03**	**8.7**

4.0 REGULATORY REVIEW AND APPLICABILITY

The USEPA and VDEQ have promulgated regulations that establish ambient air quality standards and emissions limits for sources of air pollution. This section of the application identifies the regulations that may apply to the Project and discusses how CPV Smyth will comply with all applicable requirements.

The federal regulations reviewed here include: National Ambient Air Quality Standards (NAAQS); PSD and New Source Review (NSR) requirements; New Source Performance Standards (NSPS); National Emission Standards for Hazardous Air Pollutants (NESHAP); Acid Rain Program; Title V Operating Permit Program; and the Clean Air Interstate Rule (CAIR) / Cross State Air Pollution Rule (CSAPR).

4.1 National Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2, $PM/PM_{10}/PM_{2.5}$, nitrogen dioxide (NO_2), CO, ozone (O_3), and Pb. The VDEQ also has adopted these limits as Virginia Ambient Air Quality Standards (VAAQS) under 9 VAC 5 Chapter 30. The NAAQS have been developed for short-term periods of 24 hours or less and annual averages. The NAAQS include both "primary" and "secondary" standards where the primary standards are set to protect human health, allowing an adequate margin of safety. Secondary standards are set to protect the public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air. Provided in Table 4-1 are the NAAQS and VAAQS.

One of the primary goals of federal and state air pollution regulations is to ensure that ambient air quality is in compliance with the NAAQS. Toward this end, every area of the United States has been designated as attainment, unclassifiable, or nonattainment for each criteria pollutant. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of, such air quality. In areas designated as unclassifiable, there is limited air quality data and these areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment for a particular pollutant, the air quality with respect to that pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo NSR air permitting. The NSR air permitting regulations contain two distinct programs, one for sources proposed in attainment/unclassifiable areas and one for sources in nonattainment areas. The NSR program for sources in attainment/unclassifiable areas is known as the PSD Program. The NSR program for sources being built in non-attainment areas is known as Nonattainment NSR or NNSR. The Project is located in an area classified as "attainment" or "attainment/ unclassifiable" for all criteria pollutants. Thus, emissions of criteria pollutants from the Project are evaluated under the PSD program. The requirements of the PSD program are discussed in Section 4.2.

Table 4-1: National and Virginia Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS / VAAQS (µg/m³)	
		Primary	Secondary
NO_2	Annual[1]	100	Same
	1-hour[2]	188	None
SO_2	Annual[1,3]	80	None
	24-hour[3,4]	365	None
	3-hour[4]	None	1,300
	1-hour[5,6]	196	None
$PM_{2.5}$	Annual[7]	12	Same
	24-hour[8]	35	Same
PM_{10}	24-hour[9]	150	Same
CO	8-hour[4]	10,000	None
	1-hour[4]	40,000	None
O_3	8-hr[10]	147	Same
Pb	3-month[1]	0.15	Same

1 Not to be exceeded.
2 Compliance based on 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area.
3 The 24-hour and annual average primary standards for SO_2 been revoked but remain in effect until one year after Smyth County has been designated for the 1-hour and 3-hour standards, which has yet to occur..
4 Not to be exceeded more than once per year.
5 Compliance based on 3-hear average of 99th percentile of the daily maximum 1-hour average at each monitor within an area.
6 The 1-hour SO_2 standard was effective as of August 23, 2010.
7 Compliance based on 3-year average of weighted annual mean $PM_{2.5}$ concentrations at community-oriented monitors.
8 Compliance based on 3-year average of 98th percentile of 24-hour concentrations at each population-oriented monitor within an area.
9 Not to be exceeded more than once per year on average over 3 years.
10 Compliance based on 3-year average of fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area.

4.2 Prevention of Significant Deterioration Review

The PSD Air Quality Program, which is implemented by the VDEQ, is a federally mandated program review of major new sources of criteria and other PSD-regulated pollutants primarily designed to maintain attainment with the NAAQS and prevent degradation of air quality in attainment/unclassifiable areas. Under the PSD program, a combined-cycle electric generation facility is considered a major source if emissions of any single criteria pollutant are greater than 100 tons per year (tpy) or if GHG emissions exceed 100,000 tpy. The Project will have potential emissions greater than 100 tpy for one or more criteria pollutants and potential GHG emissions greater than 100,000 tpy. Therefore, the proposed Project will be subject to the requirements of the PSD program.

Once a project exceeds one of the PSD major source thresholds, the PSD regulations also apply to each criteria pollutant that is emitted in excess of its respective defined significant emission rate. Table 4-2 presents a comparison of the Project's potential emissions versus the PSD major source and significant emission rate thresholds. As shown in Table 4-2, the facility is subject to PSD review for NO_x, CO,

$PM/PM_{10}/PM_{2.5}$, VOC, H_2SO_4 and GHGs. (See Section 3.2 for the assumptions used in determining annual potential emissions.)

Table 4-2: Prevention of Significant Deterioration Regulatory Threshold Evaluation

Pollutant	Project Potential Annual Emissions (tons)	PSD Major Source Threshold (tons)	PSD Significant Emission Rate (tons)	PSD Review Applies?
CO	105.6	100	100	Yes
NO_x	157.2	100	40	Yes
SO_2	26.6	100	40	No
PM	80.1	100	25	Yes
PM_{10}	80.1	100	15	Yes
$PM_{2.5}$	80.1	100	10	Yes
VOC (ozone precursor)	46.3	100	40	Yes
Sulfuric Acid Mist	17.3	100	7	Yes
GHGs (as CO_{2e})	2,335,189	100,000	75,000	Yes
Lead	0.009	100	0.6	No
Fluorides	Negligible	100	3	No
Hydrogen Sulfide (H_2S)	none expected	100	10	No
Total Reduced Sulfur (inc. H_2S)	none expected	100	10	No
Reduced Sulfur Compounds (inc. H_2S)	none expected	100	10	No

The key requirements for obtaining a PSD permit are a demonstration that BACT requirements are satisfied and an air quality impact analysis is completed to document compliance with the NAAQS and PSD increments, which are concentrations of allowable air quality degradation from a baseline ambient concentration. Section 5 of this application presents a detailed control technology analysis demonstrating how the Project will satisfy BACT under USEPA and VDEQ requirements. An air dispersion modeling analysis is being provided under separate cover to document that the Project will comply with the NAAQS and PSD increments.

4.3 Nonattainment New Source Review

If a major source of pollution is proposed in an area designated as nonattainment for a particular pollutant, the source is subject to NNSR for that pollutant. All of Virginia is designated as attainment or unclassifiable for all pollutants with the exception of the northeast portion of the state adjacent to the metropolitan Washington D.C. area, which has areas designated as nonattainment for ozone and $PM_{2.5}$. The Project will be located in southwest Virginia in Smyth County, which is designated as attainment or unclassifiable for all pollutants, and therefore, NNSR will not apply to the Project.

4.4 Virginia Minor Source Preconstruction Air Permitting (9 VAC 5-80)

9 VAC 5 Chapter 80, Part II, Article 6 specifies the preconstruction air permitting requirements for minor sources of air pollution. As discussed in Section 4.2, the Project is subject to PSD major source permitting for emissions of NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOC, H_2SO_4, and GHG, while potential controlled emissions of SO_2, and the other regulated pollutants listed in Table 4-2 are below their respective PSD permitting thresholds. However, potential emissions of SO_2 exceeds 10 tpy and, therefore, emissions of this pollutant are subject to the requirements of 9 VAC 5 Chapter 80, Part II, Article 6. Except for SO_2 and the PSD applicable pollutants, all other pollutant uncontrolled potential emissions are less than the thresholds specified in this article. Pursuant to 9 VAC 5-50-260.B, SO_2 emissions are subject to BACT requirements as defined under 9 VAC 5-50-250, which is similar to PSD BACT as discussed in Section 4.2. NH_3 emissions also exceed 10 tpy and a BACT analysis for this pollutant is included for completeness purposes.

4.5 New Source Performance Standards

The VDEQ regulations under 9 VAC 5 Chapter 50 (9 VAC 5-50-400) incorporate by reference all the federal NSPS promulgated by the USEPA in 40 CFR 60. The USEPA has established NSPS for numerous specific industries and emission source types. For the Project, the following NSPS are applicable to proposed emission sources:

- Stationary Combustion Turbines (40 CFR 60, Subpart KKKK);
- Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc); and
- Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII).

4.5.1 40 CFR 60 Subpart KKKK

40 CFR 60 Subpart KKKK applies to stationary combustion turbines with a heat input rating greater than or equal to 10 MMBtu/hr, which commenced construction, reconstruction, or modification after February 18, 2005. 40 CFR 60 Subpart KKKK also applies to emissions from any associated HRSGs or duct burners and, therefore, includes both the combustion turbines and the supplementary gas-fired duct burners at the Project.

40 CFR 60 Subpart KKKK provides a NO_x concentration emission standard, expressed in units of ppmvd at 15% O_2, and an output-based emission standard expressed in units of pounds per megawatt-hour gross energy output (lb/MW-hr). A subject combustion turbine must comply with one of these standards. The applicable NO_x standards for the Project are 15 ppmvd at 15% O_2 or 0.43 lb/MW-hr. As discussed in Section 5, BACT for the Project is a NO_x concentration emission limit of 2 ppmvd at 15% O_2 and as a result, NO_x emissions from the combined cycle generating units will be well below the NSPS standard.

The SO_2 standards are an output-based emission limit of 0.90 lb/MWh or a fuel sulfur content limit equivalent to an emission limit of 0.060 lbs/MMBtu. The Project will meet the NSPS for SO_2 by using natural gas as the sole fuel with a sulfur content not exceeding 0.5 gr/100 scf of natural gas, which is equivalent to 0.0014 lbs/MMBtu, well below the NSPS standard.

4.5.2 40 CFR 60 Subpart Dc

The Project will include a natural gas-fired auxiliary boiler to provide steam during plant startup. Based on the design rating for the auxiliary boiler of 93 MMBtu/hour, this unit will be subject to the NSPS under 40 CFR 60, Subpart Dc, which applies to steam generating units for which construction, reconstruction, or modification is commenced after June 9, 1989, and that have a heat input rating between 10 and 100 MMBtu/hr. For boilers fired solely with natural gas, 40 CFR 60 Subpart Dc only requires initial notification and does not impose any pollutant-specific emission limits.

4.5.3 40 CFR 60 Subpart IIII

The emergency generator and fire pump engines will both be subject to the NSPS under 40 CFR 60, Subpart IIII. 40 CFR 60 Subpart IIII requires emergency generator engines to meet the non-road engine emission standards identified in 40 CFR 89.112 and 40 CFR 89.113. The fire pump engine will be subject to the emission standards identified in 40 CFR 60, Subpart IIII, Table 4. Subpart IIII requires manufacturers to produce engines that comply with these standards. CPV Smyth will purchase emergency generator and fire pump engines that comply with 40 CFR 60 Subpart IIII.

4.6 National Emission Standards for Hazardous Air Pollutants

Articles 1 and 2 of 9 VAC 5 Chapter 60 Part II incorporate by reference all the NESHAP standards promulgated by USEPA, codified in 40 CFR Parts 61 and 63. 40 CFR Part 61 was promulgated prior to the 1990 CAA Amendments and regulates eight types of hazardous substances: asbestos; benzene; beryllium; coke oven emissions; inorganic arsenic; mercury; radionuclides; and vinyl chloride. The proposed Project is not in one of the specific source categories regulated by 40 CFR Part 61 and, therefore, the requirements of 40 CFR Part 61 are not applicable.

The 1990 CAA Amendments established a list of 189 HAPs and a list of source categories believed to be the largest emitters of HAPs. The source category-specific emission standards are promulgated under 40 CFR 63 for both major and minor (area) sources of HAP emissions. 40 CFR Part 63 defines a major source of HAP as any source that has the potential to emit 10 tpy of any single HAP or 25 tpy of all HAPs in aggregate. The emission standards are based upon a Maximum Achievable Control Technology (MACT) analysis conducted by USEPA for each source category. As shown in Table 3-5, the Project will be an area source of HAPs.

NESHAPs that were evaluated for applicability to the Project include:

- Stationary Combustion Turbines (40 CFR 63, Subpart YYYY)
- Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR 63, Subpart UUUUU)
- Industrial, Commercial, and Institutional Boilers and Process Heaters for Major Sources (40 CFR 63, Subpart DDDDD)
- Industrial, Commercial, and Institutional Boilers Area Sources (40 CFR 63, Subpart JJJJJJ)
- Stationary Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ)

40 CFR 63 Subpart YYYY, applicable to stationary combustion turbines, was promulgated on March 5, 2004. However, in April 2004, USEPA proposed to "delist" natural gas-fired combustion turbines from

the NESHAP program as USEPA believed that HAP emissions from stationary combustion turbines did not pose a hazard. In August 2004, USEPA stayed (indefinitely) the combustion turbine NESHAP for natural gas-fired turbines, and any unit that fires oil less than 1,000 hours per year, pending a final decision on delisting. Therefore, NESHAP 40 CFR 63 Subpart YYYY is not currently applicable to the Project's combustion turbines.

The HRSGs equipped with duct burners are considered electric utility steam generating units under the NESHAP regulations. 40 CFR 63 Subpart UUUUU provides standards for coal- and oil-fired electric utility steam generating units. However, natural gas-fired electric utility steam generating units are exempt from the requirements of 40 CFR 63 Subpart UUUUU. Since the duct burners are fired solely with natural gas, 40 CFR 63 Subpart UUUUU is not applicable to the Project.

40 CFR 63 Subparts DDDDD and JJJJJJ are for the same source category, which is industrial, commercial and institutional boilers. 40 CFR 63 Subpart DDDDD applies to major sources of HAP emissions and Subpart JJJJJJ applies to minor, or area, sources of HAP emissions. As shown in Table 3-5, the Project will be a minor source of HAP emissions and, therefore, would fall under 40 CFR 63 Subpart JJJJJJ. However, natural gas fired boilers are exempt from the requirements of 40 CFR 63 Subpart JJJJJJ and since the auxiliary boiler is fired solely with natural gas, it is exempt from 40 CFR 63 Subpart JJJJJJ.

40 CFR 63 Subpart ZZZZ applies to stationary reciprocating internal combustion engines at both major and non-major sources of HAP. The emergency generator and the fire pump engines for the project will be subject to 40 CFR 63 Subpart ZZZZ. In accordance with 40 CFR 63 Subpart ZZZZ, a new engine that satisfies the requirements of NSPS 40 CFR 60, Subpart IIII is deemed to be compliant with NESHAP 40 CFR 63 Subpart ZZZZ. As discussed in Section 4.5, the Project's emergency generator and fire pump engines will comply with NSPS 40 CFR 60, Subpart IIII and, therefore, will also comply with NESHAP 40 CFR 63 Subpart ZZZZ.

4.7 Federal Acid Rain Program

New electric generating units that have a generating capacity greater than 25 MW and produce electricity for sale, are subject to the federal Acid Rain Program under 40 CFR 72. The Project's two combined cycle generating units will be subject to the Acid Rain Program, which requires that an Acid Rain permit application be submitted to the permitting authority at least 24 months prior to commencement of operation. In addition to the requirement to obtain a permit, the Acid Rain program requires that subject sources secure SO_2 allowances to cover actual SO_2 emissions and install CEMS that satisfy the requirements of 40 CFR 75.

CPV Smyth will purchase each year sufficient Acid Rain SO_2 allowances to cover actual emissions from the combined cycle generating units. Since the units will be fired solely with natural gas, SO_2 emissions will be minor and the required offsets will be readily available.

The requirements of 40 CFR 75 will apply to the combined cycle combustion turbines and the associated duct burners, and include comprehensive requirements for monitoring, recordkeeping, and reporting of NO_x, SO_2 and carbon dioxide (CO_2) emissions. Affected generating units must install and operate a CEMS for NO_x, SO_2, and CO_2 emissions and must also prepare and maintain a monitoring plan that describes the methodologies used to measure and report emissions. The CEMS must satisfy detailed equipment specifications, test procedures, and quality assurance and quality control procedures to ensure the accuracy and validity of the CEMS data. CPV Smyth will install and operate CEMS that satisfy all of

the requirements of 40 CFR 75, which will be documented in the monitoring plan required to be prepared and submitted to the VDEQ and USEPA.

4.8 Title V Operating Permit

Virginia has been delegated authority by USEPA to administer the federal Title V operating permit program (40 CFR 70) under its regulations at 9 VAC 5 Chapter 80. In accordance with the requirements of Virginia's Title V operating permit program, all facilities subject to the Acid Rain program are subject to the Title V operating permit program. The Title V operating permit program requirements for Acid Rain sources are provided under 9 VAC 5 Chapter 80, Part III, Article 3 of the VDEQ regulations. In accordance with 9 VAC 5-80-430(C) of these regulations, CPV Smyth shall submit a complete Title V operating permit application no later than 12 months after the commencement of operation of the facility.

4.9 Compliance Assurance Monitoring

The Compliance Assurance Monitoring requirements under 40 CFR Part 64 apply to any emission unit located at a source required to obtain a Title V operating permit, if that emission unit satisfies all of the following requirements:

- Is subject to an emission limit or standard for a regulated pollutant;
- Uses a control device to achieve compliance with that limit or standard; and
- Has uncontrolled potential emissions of that regulated pollutant in excess of the major source threshold.

The combined cycle turbines and duct burners have uncontrolled potential emissions of NO_x and CO above the major source threshold and use a control device to meet an emission limit. Therefore, the combined cycle turbines and duct burners meet all three requirements for CAM applicability. However, in accordance with 40 CFR 64.2(b)(vi), the CAM regulations exempt sources with a Title V Operating Permit that specifies a continuous compliance determination method for the pollutant(s) that would otherwise be subject CAM. The Project will install and operate CEMS to quantify NO_x and CO emissions in units of measure consistent with the applicable emission standards and, therefore, the combined cycle turbines and duct burners will be exempt from CAM requirements.

4.10 Clean Air Interstate Rule

The Project's two combined cycle generating units will be subject to the requirements of the Clean Air Interstate Rule (CAIR) program implemented under the VDEQ regulations at 9 VAC 5-140. Although the CAIR program was replaced by USEPA with the CSAPR program in August 2011, Virginia continues to maintain its CAIR requirements since the CSAPR was vacated by the United States Court of Appeals for the District of Columbia Circuit on August 12, 2012.

The CAIR program in Virginia consists of three separate emissions trading program: (1) annual NO_x emissions (9 VAC 5-140, Part II); (2) ozone season NO_x emissions (9 VAC 5-140, Part III); and (3) annual SO_2 emissions (9 VAC 5-140, Part IV). Similar to the Acid Rain program, CPV Smyth must obtain a CAIR permit prior to operation of the facility and install and operate CEMS to measure NO_x and SO_2 emissions. However, unlike the Acid Rain program, the facility will be allocated annual and ozone season NO_x emission allowances in accordance with 9 VAC 5-140-1420 and 9 VAC 5-140-2420, respectively. The allocated emission allowances may cover, in part or in whole, the facility's actual NO_x emissions in any given year. If insufficient NO_x allowances are allocated to the facility for any given

year, then sufficient additional NO_x allowances will be secured to cover all of the facility's annual and ozone season NO_x emissions. No SO_2 emission allowances will be allocated to the facility and, therefore, SO_2 allowances will be secured to cover the facility's actual annual SO_2 emissions each year.

CPV Smyth will obtain a CAIR permit prior to the commencement of operation. The CEMS installed pursuant to the requirements of the Acid Rain program satisfy the CEMS requirements of the CAIR program. CPV Smyth will secure sufficient NO_x and SO_2 allowances, not otherwise allocated, to cover actual emissions each year.

4.11 Federal Greenhouse Gas Reporting

USEPA regulations at 40 CFR Part 98 require activities in certain source categories to report emissions of the greenhouse gases CO_2, methane (CH_4), and nitrous oxide (N_2O). The collective emissions of CO_2, CH_4, and N_2O are converted to CO_2e using the global warming potential of each substance in 40 CFR 98, Subpart A. Emission units subject to the Acid Rain program are categorically subject to the requirements of 40 CFR 98 Subpart D. The combined cycle combustion turbines and associated duct burners will be regulated under 40 CFR 98 Subpart D, which specifies that CO_2 emissions will be monitored as required under 40 CFR 75, and converted to metric tons for reporting under 40 CFR 98.

40 CFR 98 Subpart C applies to fuel combustion sources, excluding electric generating units under 40 CFR 98 Subpart D and emergency equipment as defined under 40 CFR Part 98.6, with a combined heat input capacity of 30 MMBtu/hr or greater at facilities emitting at least 25,000 metric tons of CO_2e per year. The auxiliary boiler is not an electric generating unit, and will be regulated under 40 CFR 98 Subpart C. Emissions of CO_2, CH_4, and N_2O from the auxiliary boiler will be calculated using the appropriate equations in 40 CFR 98 Subpart C of 40 CFR 98. The emergency generator and fire pump engines are emergency equipment as defined under 40 CFR Part 98.6 and, therefore, exempt from the requirements of 40 CFR 98.

Per the requirements of 40 CFR 98 Subpart D, emissions of CH_4 and N_2O from the combined cycle units will be calculated using the appropriate equations for combustion sources in 40 CFR 98 Subpart C.

Total CO_2e emissions from the combined cycle combustion turbines and auxiliary boiler and reported to the USEPA by March 31st each year via USEPA's Electronic Greenhouse Gas Reporting Tool.

4.12 Chemical Accident Prevention

Section 112(r) of the CAA and associated USEPA regulations at 40 CFR 68 apply to owners or operators of stationary sources producing, processing, handling or storing toxic or flammable substances. The substances regulated under Section 112(r) and their threshold quantities are listed at Section 68.130 of 40 CFR 68. The Project will not store any regulated substances above a threshold quantity and, therefore, is not required to prepare a Risk Management Plan in accordance with 40 CFR 68. However, the general duty clause in 112(r)(1) of the CAA will apply, which requires that the facility identify potential hazards from the accidental release of a substance, implement design safety features, and maintain a safe facility as necessary to minimize the consequences of an accidental release. CPV Smyth will take steps necessary to meet the general duty provisions.

4.13 Greenhouse Gas Permitting Requirements (9 VAC 5-85)

The project will be subject GHG permitting requirements as the in accordance with 9 VAC 5-85 as potential CO2e emissions will be in excess of 100,000 tpy. This application satisfies the GHG permitting requirements by meeting the PSD permitting requirements as discussed in Section 4.2.

4.14 Virginia Air Toxics (9 VAC 5-60)

Articles 1 and 2 of 9 VAC 5 Chapter 60 Part II incorporate by reference all the NESHAP standards promulgated by USEPA in 40 CFR 61 and 40 CFR 63. There are no 40 CFR 61 standards (Article 1 of 9 VAC 5 Chapter 60) that apply to the facility. As discussed in Section 4.5, the Project's combustion turbines, HRSGs with duct burners, auxiliary boiler and emergency engines are subject to NESHAP standards under 40 CFR 63. However, Article 5 of 9 VAC 5 Chapter 60 includes additional air toxics regulations for new sources of air toxics emission. Sources covered by an existing NESHAP standard are exempt from Article 5 in accordance with 5-60-300.C.4. However, as NESHAP Subpart YYYY has been stayed by the USEPA and is not currently in affect, the exemption under 5-60-300.C.4 is not available to the combustion turbines.

An analysis of air toxic emissions from the combustion turbines was conducted to determine if the potential emissions of any air toxic with a Threshold Limit Value (TLV®) exceeded an exemption threshold as defined under 5-60-300.C.1. Based upon this analysis, the potential emissions of three air toxics from the combustion turbines exceeded an exemption threshold. Sources subject to Article 5 of 9 VAC 5 Chapter 60 must implement BACT for subject pollutants and demonstrate that ambient impacts are less than the VDEQ's Significant Ambient Air Concentration (SAAC) as defined under 9 VAC 5-60-330. BACT will be satisfied by the firing of natural gas and the emission controls implemented to satisfy PSD BACT as discussed in Section 4.2. An evaluation of ambient air impacts from the combustion turbines for subject air toxics was conducted to demonstrate that maximum predicted impacts are below the applicable SAAC.

Emission calculations for air toxics are provided in Appendix B of this document. The ambient air impact analysis is provided under separate cover with the PSD ambient air impact analysis.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

5.1 Introduction

As discussed in Section 4.2, a PSD BACT analysis is required for emissions of NO_x, CO, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, VOC, and GHGs from the Project in accordance with 9 VAC 5-80-1705 and 9 VAC 5-50-280. BACT is also required for minor source emissions of SO_2 in accordance with 9 VAC 5-50-260 as discussed in Section 4.4. The following control technology analysis satisfies the BACT requirements for all subject pollutants and emission units for the Project.

5.1.1 Definition of BACT

The VDEQ regulations define "Best Available Control Technology" under 9 VAC 5-50-250 as follows:

> "...a standard of performance (including a visible emission standard) based on the maximum degree of emission reduction for any pollutant which would be emitted from any proposed stationary source which the board, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source through the application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard in Article 5 (9 VAC 5-50-400 et seq.) of this part or Article 1 (9 VAC 5-60-60 et seq.) of Part II of 9 VAC 5 Chapter 60. If the board determines that technological or economic limitations on the application of measurement methodology to particular emissions unit would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination of them, may be prescribed instead of requiring the application of best available control technology. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

With regard to pollutants subject to Article 6 of Part II of 9 VAC 5-80, SO_2 BACT is further defined under 9 VAC 5-50-250 as follows:

> "In determining best available control technology for stationary sources subject to Article 6 (9 VAC 5-80-1100 et seq.) of Part II of 9 VAC 5 Chapter 80, consideration shall be given to the nature and amount of the new emissions, emission control efficiencies achieved in the industry for the source type, and the cost-effectiveness of the incremental emission reduction achieved."

5.1.2 BACT Process

Per USEPA guidance, a PSD BACT analysis must be conducted using a "top down" approach. In a "top-down" BACT analysis, all control technologies for a subject pollutant are identified and ranked from most to least efficient. An evaluation of each technology is then conducted to determine if it is technically feasible for the proposed project and if so, the resulting energy, environmental and economic impacts from its application. The most efficient technology that is determined to be technically feasible and does not result in adverse energy, environmental and/or economic impacts, is selected as BACT.

The BACT process described in USEPA's draft document titled "*New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*" (NSR Manual) (USEPA, 1990), which acts as a non-binding guidance document for USEPA, state permitting authorities and permit applicants during the permitting process. The BACT process is conducted on a pollutant by pollutant basis for each emission unit that emits that pollutant. The process involves the following five steps:

Step 1: Identify all potential control technologies applicable to the pollutant and process.

Step 2: Determine the technical feasibility of each control technology identified under Step 1 as applicable to the Project and eliminate those that are infeasible.

Step 3: Rank the technically feasible control technologies based on overall control efficiency.

Step 4: Evaluate the most effective control technology based on economic, energy, and environmental factors. If the most effective control technology causes unacceptable economic, energy, and/or environmental impacts, the next most effective technology is evaluated. This process continues until a technology is selected as BACT.

Step 5: Select the most effective option not eliminated in Steps 2 – 4 above as BACT and determine the corresponding emission limit for the subject pollutant and emission source.

Per this guidance, if a project elects to implement the "top" technically feasible level of control identified in Steps 1 and 2, then no further analysis is required.

5.1.3 Sources Reviewed To Identify BACT

Steps 1 and 2 in the BACT process are the identification of all available control technologies and the top level of control for each subject pollutant from each source type for the project. Per USEPA guidance, BACT may be achieved from a change in raw materials, a process modification, and/or add-on pollution controls. For the Project, the cleanest raw material (natural gas) and lowest emitting fossil-fuel generating process (combined cycle combustion turbines) have been selected. Therefore, the identification of the top level of control focused on add-on pollution controls.

Per USEPA guidance, BACT is expressed as an emission rate and the top level of control is determined from the following:

- The most stringent emissions limitation which is contained in any State Implementation Plan (SIP) for such class or category of stationary source; or
- The most stringent emissions limitation which is achieved in practice by such class or category of stationary source.

In order to identify the "most stringent emissions limitation which is achieved in practice" by a combined cycle combustion turbine facility, numerous sources of information were evaluated. These sources included the following:

- USEPA's RACT, BACT, LAER Clearinghouse (RBLC);
- The California Air Resources Board (CARB) BACT Clearinghouse;
- USEPA regional air permitting websites; and
- State environmental agency websites.

In addition to these sources of information, additional publicly available information obtained through Tetra Tech's experience, such as permits for individual projects not listed in the RBLC or agency websites, were also included in the analysis.

5.2 Combined Cycle Combustion Turbines and Duct Burners

The BACT analysis for the combustion turbines and duct burners is combined as the duct burners cannot operate without the combustion turbines in operation. Since the combustion turbines can operate with and without duct firing, BACT emission rates were reviewed for both of these operating scenarios. Provided in Table 5-1 is a summary of recently permitted emission limits for combined cycle combustion turbine projects larger than 100 MW. Table 5-1 provides the permitted emission limits for each criteria pollutant from the Project subject to BACT requirements. Permitted BACT GHG emission limits for combined cycle combustion turbine projects are provided separately in Section 5.2.8. The emission limits provided in Table 5-1 serve as the basis for determining the "most stringent emissions limitation which is achieved in practice" for large combined cycle combustion turbines.

5.2.1 Nitrogen Oxides (NO_x)

NO_x emissions can be controlled using combustion controls and/or flue gas treatment. For the combustion turbines, available combustion controls include dry low-NO_x (DLN) combustors and the most common flue gas treatment is SCR. DLN combustors are designed to minimize the formation of NO_x from fuel combustion while SCR is placed in the combustion turbine exhaust to further reduce emissions. For the duct burners, available combustion controls include low-NO_x burners (LNB). An SCR will control NO_x emissions from both the combustion turbines and duct burners.

An SCR system is composed of an ammonia storage tank, ammonia forwarding pumps and controls, an injection grid (a system of nozzles that spray ammonia into the exhaust gas ductwork), a catalyst reactor, and instrumentation and controls. The injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to nitrogen and water by the catalyst. SCR catalysts operate efficiently within a wide range of temperatures. For base metal catalysts typically used on combined cycle combustion turbine projects, the effective operating temperature range is between 450°F and 850°F. Since combined cycle combustion turbine projects employ a HRSG to produce steam from the hot exhaust gases in order to generate additional electricity in a steam turbine, the SCR can be placed within the HRSG under its optimum temperature window to maximize NO_x reduction.

All of the projects listed in Table 5-1 have been permitted to utilize DLN combustors and SCR to achieve the permitted NO_x emission levels. Accordingly, the Project is proposing to use state of the art DLN combustors in combination with SCR to control NO_x emissions from the turbines as well as LNB for the duct burners.

Based on a review of recently permitted projects, 2.0 ppm corrected to 15% O_2 on a 1-hour averaging basis was determined to be the most stringent emission limit achieved in practice and is selected as BACT for the Project. Since the top level of control was selected, an evaluation of the economic, energy, and environmental impacts is not necessary. BACT will be demonstrated on a continuous basis through the application of a CEMS to monitor NO_x and O_2 concentrations and calculate the emission rate in units of the BACT emission limit.

Table 5-1: Summary Of Recent PSD Criteria Pollutant BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine	Emission Limits and Controls				
				NO_x[1] (ppm)	CO[1] (ppm)	VOC[1] (ppm)	$PM_{10}/PM_{2.5}$[2] (lb/MMBtu)	H_2SO_4 (lb/MMBtu)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	GE 7FA	2.0 (w/ and w/o DF[3]) LAER	2.0 (w/ and w/o DF)	1.0 (w/o DF) 2.4 (w/ DF)	0.00334[4] (w/ and w/o DF)	N/A
Brunswick County Power	Freeman, VA	05/23/2012	Mitsubishi M501 GAC	2.0 (w/ and w/o DF)	1.5 (w/o DF) 2.4 (w/ DF)	0.7 (w/o DF) 1.6 (w/ DF)	0.0033 (w/o DF) 0.0047 (w/ DF)	0.0058 (w/o DF) 0.0067 (w/ DF)
Dominion Warren County	Front Royal, VA	12/21/2010	Mitsubishi M501 GAC	2.0 (w/ and w/o DF)	1.5 (w/o DF) 2.4 (w/ DF)	0.7 (w/o DF) 1.6 (w/ DF)	0.0027 (w/o DF) 0.0040 (w/ DF)	0.00013 (w/o DF) 0.00025 (w/ DF)
Carroll County Energy	Washington Twp., OH	11/5/2013	GE 7FA	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	1.0 (w/o DF) 2.0 (w/ DF)	0.0108 (w/o DF) 0.0078 (w/ DF)	0.0012 (w/o DF) 0.0016 (w/ DF)
Renaissance Power	Carson City, MI	11/1/2013	Siemens 501 FD2	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	0.0042 (w/ and w/o DF)	N/A
Langley Gulch Power	Payette, ID	08/14/2013	Siemens SGT6-5000F	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	0.0053 (w/ and w/o DF)	N/A
Kleen Energy	Middletown, CT	07/2/2013	Siemens SGT6-5000F	2.0 (w/ and w/o DF)	0.9 (w/o DF) 1.7 (w/ DF)	5.0 (w/ and w/o DF)	0.0051 (w/o DF) 0.0059 (w/ DF)	0.0006 (w/o DF) 0.0007 (w/ DF)
Oregon Clean Energy	Oregon, OH	06/18/2013	Siemens SCC6-8000H	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	0.0047 (w/o DF) 0.0055 (w/ DF)	0.0006 (w/o DF) 0.0007 (w/ DF)
TECO Polk Power 2	Mulberry, FL	05/15/2013	GE 7FA	2.0 (w/ and w/o DF)	4.1 (no ox. cat)	1.4 (no ox. cat)	N/A	2 gr S/100ft^3 of gas
Sunbury Generation	Sunbury, PA	04/01/2013	"F Class"	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	1.0 (w/o DF) 3.9 (w/ DF)	0.0088 (w/ and w/o DF)	0.0018
Hess Newark Energy	Newark, NJ	11/01/2012	GE 7FA.05	2.0 (w/ and w/o DF) LAER	2.0 (w/ and w/o DF)	1.0 (w/ and w/o DF)	0.00474 (w/o DF) 0.00583 (w/ DF)	0.00008 (w/o DF) 0.0006 (w/ DF)
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	"F Class"	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	1.0 (w/o DF) 1.5 (w/ DF)	0.0057 (w/ and w/o DF)	0.0002
Cricket Valley Energy Center	Middleton, NY	09/27/2012	"F Class)	2.0 (w/ and w/o DF) LAER	2.0 (w/ and w/o DF)	1.0 (w/o DF) 2.0 (w/ DF) LAER	0.005 (w/o DF) 0.006 (w/ DF)	N/A
Deer Park Energy	Harris, TX	09/26/2012	Siemens West. 501F	2.0 (w/ and w/o DF)	4.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	0.010 (w/ and w/o DF)	N/A

Table 5-1: Summary Of Recent PSD Criteria Pollutant BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine	Emission Limits and Controls				
				NO_x[1] (ppm)	CO[1] (ppm)	VOC[1] (ppm)	$PM_{10}/PM_{2.5}$[2] (lb/MMBtu)	H_2SO_4 (lb/MMBtu)
ES Joslin Power	Calhoun, TX	09/12/2012	GE 7FA	2.0 (w/ and w/o DF)	4.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	0.010 (w/ and w/o DF)	N/A
Pioneer Valley Energy Center	Westfield, MA	04-12-2012	Mitsubishi 501G	2.0 (w/ and w/o DF) LAER	2.0 (w/ and w/o DF)	N/A	0.0040 (w/ and w/o DF)	N/A
Thomas C. Ferguson Power	Llano, TX	09/01/2011	GE 7FA	2.0 (no DF)	4.0 (no DF)	2.0 (no DF)	0.018 (no DF)	0.0078
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	GE 7FA	2.0 (w/ and w/o DF)	2.0 (w/o DF) 3.0 (w/ DF)	N/A	0.0048 (w/o DF) 0.0049 (w/ DF)	N/A
Avenal Power Center	Avenal, CA	05/27/2011	GE 7FA	2.0 (w/ and w/o DF)	2.0 (w/ and w/o DF)	N/A	11.78 lb/hr w/ DF 8.91 lb/hr w/o DF	N/A
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	Mitsubishi M501GAC	2.0 (w/ and w/o DF)	N/A	N/A	0.0025 (w/ and w/o DF)	N/A
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	2.5 (no DF)	2.0 (w/o DF) 3.2 (w/ DF)	2.0 (no DF)	N/A	0.5 gr S/100ft^3 of gas
Victorville 2 Hybrid	Victorville, CA	03-11-2010	GE 7FA	2.0 (w/ and w/o DF)	2.0 (w/o DF) 3.0 (w/ DF)	N/A	18.0 lb/hr w/ DF 12.0 lb/hr w/o DF	N/A
High Desert Power	Victorville, CA	03-11-2010	Siemens West. 501F	2.5 (w/ and w/o DF)	4.0 (w/ and w/o DF)	N/A	N/A	N/A
Wolf Hollow Power	Hood, TX	03/03/2010	GE 7FA	2.0 (w/ and w/o DF)	10.0 (no ox. cat)	3.0 (no ox. cat)	N/A	N/A
Panda Sherman Power	Grayson, TX	02/03/2010	GE 7FA	2.0 (w/ and w/o DF)	15.0 (no ox. cat)	4.0 (no ox. cat)	N/A	N/A

[1] Concentration in ppm is parts per million by volume, dry, at 15 percent O_2.

[2] Concentration in pounds per million Btu heat input (HHV), except as noted, including front (filterable) and back-half (condensable) PM.

[3] DF refers to duct firing

5.2.2 Carbon Monoxide (CO)

CO is emitted from combustion turbines and duct burners as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. The most stringent CO add-on pollution control technology is an oxidation catalyst, which is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst; the catalyst oxidizes the CO to CO_2. For a combined cycle combustion turbine, the oxidation catalyst is placed in the HRSG in front of the SCR catalyst so that it will operate at or above the SCR catalyst temperature.

With a few exceptions, the great majority of projects listed in Table 5-1 have been permitted with an oxidation catalyst to achieve the permitted CO emission levels, including the three most recent projects in Virginia. Accordingly, the Project is proposing to use an oxidation catalyst to control CO emissions from the combustion turbines and duct burners.

A review of recently permitted projects shows that most are permitted at an emission rate at or above 2.0 ppm corrected to 15% O_2 on a 1-hour averaging basis during all operating periods. A few projects have marginally lower permitted limits without duct firing and one project has a lower limit with duct firing, but these projects have a different combustion turbine than the Alstom GT24 and cannot operate down to the very low minimum operating load of the Alstom GT24 turbine. For these reasons, 2.0 ppm corrected to 15% O_2 on a 1-hour averaging basis was selected as BACT for all operating cases, consistent with the preponderance of projects listed in Table 5-1. BACT will be demonstrated on a continuous basis through the application of a CEMS to monitor CO and O_2 concentrations and calculate the emission rate in units of the BACT emission limit.

5.2.3 Volatile Organic Compounds (VOCs)

Similar to CO emissions, VOCs are emitted from combustion turbines as a result of incomplete oxidation of the fuel. VOC emissions from combustion turbines can be minimized by the use of proper combustor design and good combustion practices. Depending upon the species of VOCs in the turbine exhaust, the oxidation catalyst employed to reduce CO emissions may also reduce VOC emissions but the reduction in VOC emissions is expected to be modest. Therefore, the critical control technique for VOC emissions is proper combustor design and good combustion practices.

VOC emissions from duct burners are typically higher than from the combustion turbine. A review of the permitted projects in Table 5-1 shows a range of permitted VOC emission limits, most with an allowable emission rate that is higher during duct firing of the HRSG. The permitted VOC emission limit for any combustion turbine project will be dependent upon the make and model of the combustion turbine selected and the vendor guaranteed emission rate. The combustion turbine selected for the Project is an Alstom GT24, for which there is no comparable project in Table 5-1.

The Alstom GT24 was selected for the Project due to its unique ability to enable the combined cycle power plant to meet its permitted BACT emission rates at LLO, allowing the GT24 unit to cycle up and down and follow the projected demand in the area. Since the turbines can operate at LLO, it will minimize startup and shutdown (SU/SD) operation during which VOC emissions are elevated as compared to steady state operation. For comparison, the combustion turbines permitted in Table 5-1 will typically have a minimum operating load of 50%, below which, they cannot meet their permitted BACT emission rates. As a result, these other turbine models could require a significant amount of SU/SD operation and consequently, increased VOC emissions as a result.

Based upon Alstom's expected VOC emissions from the combustion turbine, and installation of an oxidation catalyst, the proposed VOC BACT emission rates are 1.0 ppm corrected to 15% O_2 on a 1-hour averaging basis without duct firing and 2.0 ppm corrected to 15% O_2 on a 1-hour averaging basis with duct firing. These emission limits are consistent with the most stringent emission limits identified in Table 5-1 and equivalent to or less than the limits for the most recently permitted project in Virginia. Therefore, these limits are proposed as the top-level of control and an evaluation of the economic, energy, and environmental impacts is not necessary.

5.2.4 Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel, products of incomplete combustion and conversion of SO_2 in the exhaust to condensable salts. Conservatively, all particulate matter (PM) emissions from the Project are presumed to be less than 2.5 microns in size ($PM_{2.5}$) and, therefore, emissions of PM, PM_{10} and $PM_{2.5}$ are presumed to be equal. Particulate emissions are minimized by utilizing state of the art combustion turbines firing natural gas since natural gas has the lowest ash and sulfur content available.

A review of the permitted emission limits in Table 5-1 shows a wide range of values on a lb/MMBtu basis. Similar to VOC emissions, the permitted PM emission limit for a combustion turbine project will be dependent upon the make and model of the combustion turbine selected and the vendor guaranteed emission rate. For example, GE guarantees a flat pound per hour PM emission rate across all operating loads for their combustion turbines. This results in a wide range PM emission rates on a lb/MMBtu basis for GE turbines. A comparison of the recently permitted Green Energy Partners project in Virginia to the Carroll County project in Ohio shows a permitted PM emission rate difference of a factor of three (on a lb/MMBtu basis) for the same model GE turbine. This discrepancy results from the Green Energy Partners permitted PM emission rate in lb/MMBtu being at full operating load while the Carroll County limit lb/MMBtu is at minimum operating load.

The combustion turbine selected for the Project is an Alstom GT24, for which there is no comparable project in Table 5-1. As discussed in Section 5.2.3, the Alstom GT24 was selected for the Project in part due to its unique ability to meet its permitted BACT emission rates at very low operating loads. Due to the unique operation of the Alstom GT24, CPV Smyth does not believe the Project can be directly compared to the projects listed in Table 5-1 for PM emissions.

BACT for PM emissions from the Project are proposed to be good combustion practices, the use of natural gas with a maximum sulfur content of 0.5 gr/100 scf and the guaranteed emission rates from Alstom. Alstom's guaranteed PM emissions on a lb/MMBtu basis change depending upon operating load and ambient conditions. In order to establish BACT as an emission rate, the following limits at full operating load are proposed for the Project, including filterable and condensable PM. The pound per hour limits are absolute maximum values while the lb/MMBtu limit represents all scenarios at full operating load, including duct firing. Therefore, higher emissions at reduced operating loads may occur in terms of lb/MMBtu but no increase in mass emissions will result.

- 12.9 lbs/hr with duct firing;
- 9.4 lbs/hr without duct firing; and
- 0.005 lb/MMBtu (at full load).

Full operating load limits are proposed to establish BACT since performance emissions testing will be conducted at full operating load and this approach is consistent with the most recent combined cycle generating project permitted in Virginia. The proposed limit on a lb/MMBtu basis is within the range of recently permitted projects in Table 5-1. Further reductions in PM emissions from the turbines are not technically feasible as there are no known combustion turbines equipped with add-on PM pollution controls and the natural gas delivered to the plant will be pipeline quality.

5.2.5 Sulfur Dioxide (SO_2)

SO_2 is emitted from the combustion turbines and duct burners as a result of the oxidation of the sulfur in the fuel. The only practical means for controlling SO_2 emissions from the combustion turbines and duct burners is to limit the sulfur content of the fuel. The Project proposes to use pipeline quality natural gas as the sole fuel. Pipeline quality natural gas is the lowest sulfur content fuel commercially available and the sulfur content of the natural gas will be no greater than 0.5 gr/100 scf of gas, or approximately 0.0015 lbs SO_2/MMBtu.

5.2.6 Sulfuric Acid Mist (H_2SO_4)

In any combustion process, the sulfur in the fuel is predominantly oxidized to SO_2 but a small percentage of the sulfur is oxidized to SO_3, which reacts with moisture in the exhaust to form sulfuric acid (H_2SO_4). Similar to SO_2 emissions, the top level of control for H_2SO_4 emissions is to limit the sulfur content of the fuel. The Project proposes to use pipeline quality natural gas as the sole fuel, which is the fuel with the lowest sulfur content commercially available and therefore, represents the top level of BACT for the Project.

Alstom provided CPV with guaranteed H_2SO_4 emissions based upon their estimate of sulfur to SO_3 conversion. The maximum H_2SO_4 emission rate shall be no greater than 0.00095 lb/MMBtu, which is consistent with the permitted emission limits for projects listed in Table 5-1.

5.2.7 Ammonia (NH_3)

NH_3 is injected into the exhaust of the combustion turbines prior to the SCR to facilitate the conversion of NO_x to nitrogen and water. NH_3 is injected at a ratio slightly greater than the amount required to convert 100% of the NO_x if the SCR operated at 100% efficiency. Additional NH_3 is required mostly to offset mixing inefficiencies in the exhaust and to some degree to offset insufficient residence time for reaction of the NH_3/NO_x mixture across the catalyst. Consequently, some of the injected NH_3 does passes through the SCR unreacted and is exhausted to the atmosphere. These NH_3 emissions are called the "ammonia slip." Ammonia slip will be limited to 5.0 ppm corrected to 15% O_2 during normal operation. Ammonia will not be injected until the SCR catalyst reaches the vendor recommended minimum operating temperature to ensure a high reaction efficiency.

5.2.8 Greenhouse Gases

USEPA issued a 2011 guidance document for completing GHG BACT analyses titled "*PSD and Title V Permitting Guidance for Greenhouse Gases*". This guidance is in addition to the 1990 USEPA BACT guidance document. Although the 2011 guidance document refers to the same top-down methodology described in the 1990 document, it provides additional clarification and detail with regard to some aspects of the analysis. The following analysis has been conducted in accordance with both the 1990 and 2011 guidance documents.

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, the applicant must identify all "available" control options which have the potential for practical application to the emission unit and regulated pollutant under evaluation, including lower-emitting process and practices. In assessing available GHG control measures, the sources of information reviewed in Section 5.1.3 were reviewed with regard to GHG controls and emissions. For a combined cycle turbine project, potential GHG controls include the following:

1. low carbon-emitting fuels;
2. carbon capture and storage (CCS); and
3. energy efficiency and heat rate.

Each of these GHG control measures is evaluated in Step 2 of this analysis.

Step 2: Technical Feasibility of Potential GHG Control Options

Low Carbon-Emitting Fuels

Natural gas combustion generates significantly lower GHG emissions on a per unit of heat throughput than distillate oil (approximately 27% less) and coal (approximately 50% less). Use of biofuels, such as biodiesel, would reduce fossil-based carbon dioxide emissions, since biofuels are produced from recently harvested plant material rather than ancient plant material that has transformed into fossil fuel. However, biofuels are in liquid form, and the Project is not being designed for liquid fuel. In addition, combined cycle turbines have technical issues with biofuels that have yet to be resolved and as a result, there are no known permitted or proposed combustion turbine projects firing biofuel. In order to feasibly fire biofuel in a combustion turbine, it is expected that distillate fuel would need to be blended with biofuel, which would offset some or all of the potential reductions in GHG emissions. For this reason, biofuels were eliminated from consideration as BACT. Therefore, natural gas represents the lowest carbon fuel commercially available for the Project.

Energy Efficiency and Heat Rate

USEPA's 2011 GHG permitting guidance states:

> "Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. USEPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions..."

USEPA also recommends that permit applicants:

> "propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry."

With regard to electric generation from combustion sources, the combined-cycle combustion turbine is considered to be the most efficient technology available. GHG emissions from electricity production are primarily a function of the amount of fuel burned. Therefore, a key factor in minimizing GHG emissions is to maximize the efficiency of electricity production, or otherwise known as minimizing the heat rate.

The heat rate of an electric generating unit is the amount of heat needed to generate an amount of electricity and is usually reported in units of Btus of fuel consumed per kilowatt-hour of electricity generated (Btu/kW-hr). An efficient unit will require less fuel to generate a kilowatt-hour of electricity and have a lower heat rate. Most existing fossil-fuel fired generating units are older boilers and turbines that are less efficient than new combined cycle combustion turbine projects. In general, boilers have a higher heat rate than combined cycle combustion turbine projects that use the waste heat from the combustion turbines to generate additional power in a steam turbine. In addition to the efficiency of the electricity generation cycle itself, there are a number of key plant internal energy sinks (parasitic losses) that can improve a plant's net heat rate (efficiency) if reduced.

Measures to increase energy efficiency are technically feasible and are addressed in more detail in Step 4 of this analysis.

Carbon Capture and Storage

USEPA has specifically stated that CCS is technically achievable and must be considered in a GHG PSD BACT analysis. CCS is composed of three main components which are CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, if the temperature, pressure, pollutant concentration, and/or volume of the gas stream to be controlled differ significantly from previous applications, then it is not certain the GHG control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline for transport, access to suitable geologic reservoirs for sequestration or other storage options). While CCS is a promising technology and may be technically achievable for a specific project, USEPA has also stated that at this time CCS will be a technically feasible BACT option in certain limited cases.

As stated in the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*, co-chaired by USEPA and the United States Department of Energy, while amine- or ammonia-based CO_2 capture technologies are commercially available, they have been implemented either in non-combustion applications (i.e., separating CO_2 from field natural gas) or on relatively small-scale combustion applications (e.g., slip streams from power plants with exhaust volumes that would correspond to approximately one megawatt of generating capacity). Scaling up these capture processes would represent a very significant technical challenge and potential barrier to widespread commercial deployment in the near term. It is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that need to be addressed prior to widespread, cost-effective deployment of CO_2 capture. Current technologies could be used to capture CO_2 from new and existing fossil fuel energy

power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant applications. To date, United States power generating projects under consideration for using CCS technology have required significant government funding and have been targeted for coal fired boiler plants that have exhaust with higher CO_2 concentrations and lower exhaust volume as compared to a combustion turbine project.

Regarding pipeline transport for CCS, there does not exist a nearby existing CO_2 pipeline infrastructure (see Figure 5-1). The nearest CO_2 pipeline to the Project is in southern Mississippi, more than 500 miles from the Project in a straight line distance. The cost to construct a pipeline from the Project to Mississippi would make the Project uneconomical. Furthermore, the time necessary to acquire all required regulatory approvals and construct the pipeline would take many years.

With regard to storage for CCS, the Interagency Task Force concluded that while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes" and that "scale-up from a limited number of demonstration projects to wide scale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)."

Based on the abovementioned USEPA guidance regarding technical feasibility, the distance to the nearest CO_2 pipeline and the conclusions of the Interagency Task Force for the CO_2 capture component alone, CCS has been determined to be not technically feasible for the Project.

Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

Based on the results of Step 2, the only GHG control option technically feasible for the Project is energy efficiency.

Step 4: Evaluation of Energy Efficiency and Heat Rate

Improvements to energy efficiency and "heat rate" are important GHG control measures that can be employed to mitigate GHG emissions. The Project is proposing advanced combustion turbine combined cycle technology, which is recognized as the most efficient commercially available technology for producing electric power from fossil fuels. Improvements to the heat rate typically will not change the amount of fuel combusted for a given combustion turbine installation, but it will allow more power to be produced from a given amount of fuel (i.e., improve the heat rate) so that more GHG emissions will be displaced from existing sources.

Key factors addressed in the evaluation of energy efficiency and heat rate are the core efficiency of the selected turbines and the significant factors affecting overall net heat rate in combined cycle operating mode. The Project is proposing to install two "F" Class turbines in combined cycle configuration. "G" class turbines are slightly more efficient and thus have a lower heat rate. However, "G" class turbines generate approximately 25% more electricity per turbine and would not match the projected demand for the Project area. In addition, "G" class turbines generally have a higher low operating limit (the lowest MW output at which the facility can operate in compliance with its permits) than the proposed "F" class turbines. As previously discussed, the capability of the GT24 turbine to operate at LLO is integral to the design of the Project. By matching the projected demand for the area and minimizing startup and shutdown operation, the GT24 turbine provides greater operational flexibility and lower overall emissions. The expected heat rate differential between "F" and "G" class turbines in combined cycle

mode, is expected to be less than 1 percent at ISO conditions, without duct firing. For these reasons, "G" class machines have been eliminated from consideration for the Proposed Project.

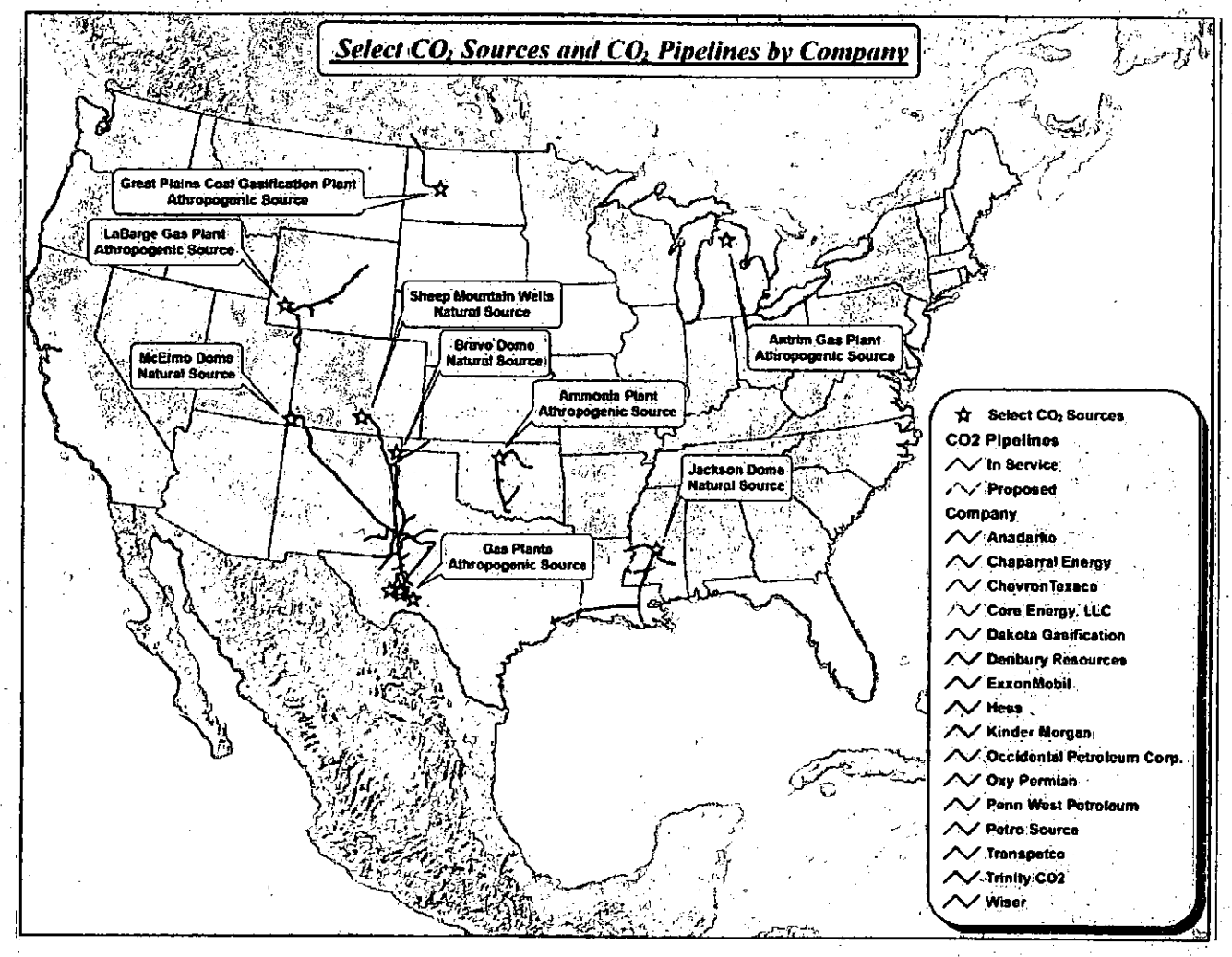


Figure 5-1 CO_2 Pipelines in the United States
From: "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, Appendix B.)

The Alstom GT24 combustion turbine is an advanced generation of "F" class machines that has higher output and improved heat rate compared to prior "F" class designs. The Alstom GT24 combustion turbine represents the current state-of-the-art for the evolving "F" class technology that has been in operation for more than 20 years with thousands of machines in operation. The steam cycle portion of the plant (HRSG, piping and steam turbine generator), designed with a single steam turbine in a "2 on 1" configuration will have a lower heat rate as compared to a separate steam turbine matched to each combustion turbine in a "1 on 1" configuration.

With regard to energy efficiency considerations in combined cycle combustion turbine facilities, the activity with the greatest effect on overall plant efficiency is the method of condenser cooling. As with all steam-based electric generation, combined cycle plants can use either dry cooling or wet cooling for condenser cooling. Dry cooling uses large fans to condense steam directly inside a series of pipes, similar in concept to the radiator of a car. Wet cooling can either be closed cycle evaporative cooling (using

cooling towers), or "once-through" cooling using very large volumes of water. Wet cooling performance is superior for efficiency purposes because of the basic thermodynamics of cooling, which produces colder water as compared to dry cooling. Additionally, dry cooling requires more electricity than wet cooling and as a result, has a higher parasitic load. As a result, operation of a dry cooling system requires approximately 1-5% more energy than a wet cooling system depending on ambient conditions as the difference between wet and dry systems gets smaller at lower ambient temperatures.

However, there are significant drawbacks to a wet cooling system. Once-through cooling uses large quantities of water that is returned to the receiving water body at a higher temperature. Wet mechanical draft cooling towers also require a significant quantity of water, mostly due to evaporation to the atmosphere. The evaporative water losses from a wet mechanical draft cooling tower impose an additional burden with the creation of a visible fog plume during certain ambient conditions.

The higher water demand for a wet cooling tower is of significant importance to the Project as the area cannot support higher water usage. For this reason, a dry cooling system with an air cooled condenser was selected for the project as wet cooling was not technically feasible.

Step 5: GHG BACT

The very low heat rates (high efficiency) associated with the combined cycle combustion turbine technology selected for the Project and the use of the lowest carbon fossil fuel, natural gas, as the exclusive fuel, represent GHG BACT for the Project.

A review of recently permitted GHG BACT emission rates was conducted and the results of this review are provided in Table 5-2. The USEPA has also proposed an NSPS standard for GHG emissions from new natural gas fired generating plants of 1,000 lb/MW-hr on a gross output basis.

The emission limits in Table 5-2 and the NSPS are all based upon CO_2e emissions over a 12-month operating period (except as noted in the table) and, therefore, account for both duct firing and non-duct firing operation. Each limit also takes into account an estimate of performance degradation of the combustion turbines over their expected lifetime. Based upon performance data of the GT24 turbine provided by Alstom and expected operation during duct firing and non-duct firing operation and predicted performance degradation, the GHG BACT emission rate for the Project was determined to be 888 lb/MW-hr on a gross output basis over a 12-month operating period.

Table 5-2: Summary Of Recent PSD GHG BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Project	Location	Permit Date	Combustion Turbine	Source	CO_2e Emission Limit		Degradation Allowance
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	GE 7FA	CT - gas firing w/ DF	903	lb/MW-hr (gross)	12.0%
Brunswick County Power	Freeman, VA	05/23/2012	Mitsubishi M501 GAC	CT - gas firing w/ DF	920	lb/MW-hr (net)	12.0%
Carroll County Energy	Washington Twp., OH	11/5/2013	GE 7FA	CT - gas firing w/ DF	859	lb/MW-hr (gross, excluding duct firing)	Unknown
Renaissance Power	Carson City, MI	11/1/2013	Siemens 501 FD2	CT - gas firing w/ DF	1,000	lb/MW-hr (gross)	Unknown
Oregon Clean Energy Center	Lucas, OH	18-Jun-2013	Mitsubishi M501 or Siemens SGT-8000H	CT - gas firing w/ DF	840	lb/MW-hr	12.8%
Calpine Deer Park	Deer Park, TX	29-Nov-2012	Siemens 501F	CT - gas firing	920	lb/MW-hr (30-day rolling)	12.8%
Channel Energy Center	Pasadena, TX	29-Nov-2012	Siemens 501F	CT - gas firing	920	lb/MW-hr (30-day rolling)	12.8%
Hess Newark Energy Center	Newark, NJ	1-Nov-2012	GE 7FA	CT - gas firing w/ DF	887	lb/MW-hr (gross)	12.8%
Cricket Valley Energy Center	Middletown, NY	09/27/2012	"F" Class	CT - gas firing w/ DF	925	lb/MW-hr (gross)	12.8%
Deer Park Energy	Harris, TX	09/26/2012	Siemens West. 501F	CT - gas firing w/ DF	920	lb/MW-hr (gross)	12.8%
Pioneer Valley Energy Center	Westfield, MA	04-12-2012	Mitsubishi 501G	CT - gas firing w/ DF	895	lb/MW-hr (gross)	8.5%
Thomas C. Ferguson	Horseshoe Bay, TX	10-Nov-2011	GE 7FA	CT - gas firing w/ DF	918	lb/MW-hr (gross)	5%
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	GE 7FA	CT – gas firing w/ DF & solar thermal	774	lb/MW-hr (net, including solar)	Unknown

The emissions and operating data used to determine the CO_2e BACT emission rate are provided below.

Non-Duct Firing Operation

Avg. Annual Temp:	59°F
Annual Operating Hours:	5,760 hrs/yr
CO_2e emissions:	468,295 lb/hr at 100% load
Gross Heat Input:	3,936 MMBtu/hr
Gross Output:	602.0 MW

Duct Firing Operation

Avg. Annual Temp:	90°F
Annual Operating Hours:	3,000 hrs/yr
CO_2e emissions:	584,699 lb/hr at 100% load
Gross Heat Input:	4,914 MMBtu/hr
Gross Output:	713.3 MW

The proposed GHG BACT emission rate takes into account a performance degradation value of 12.0% from the original design performance data. The degradation rate takes into account three performance factors predicted to impact operation of the combustion turbine over time. These factors were derived from a detailed analysis conducted by the Bay Area Air Quality Management District (BAAQMD) for the Russell City Energy Center, which used a 12.8% degradation factor and has been included in several GHG BACT decisions by USEPA. The 12.0% used for the Project was chosen to be consistent with recent VDEQ GHG BACT determinations.

The first factor taken into account in the degradation rate by the BAAQMD is design margin to reflect the likelihood that the equipment as constructed and installed may not fully achieve the optimal vendor specified design performance. A design margin of 3.3% was factored into the GHG BACT emission rate.

The second factor taken into account by the BAAQMD is performance margin to reflect normal wear and tear of the combustion turbine over its useful life. A performance margin of 6.0% was factored into the GHG BACT emission rate.

The third and final factor taken into account by the BAAQMD is degradation of auxiliary plant equipment to reflect normal wear and tear. A degradation margin for auxiliary equipment of 3.0% was factored into the GHG BACT emission rate.

These three factors were expected to compound upon each preceding factor such that the overall degradation rate used in the Russell City project was 12.8% over the useful life of the combustion turbines.

The lower degradation factors for the Thomas C. Ferguson and Pioneer Valley projects listed in Table 5-2 do not take into account all three factors that will impact the project's heat rate over its useful life. The Green Energy Partners and Brunswick County Power projects recently permitted in Virginia take into account three degradation factors in the determination of the CO_2e emission limit, however, these factors differ slightly from the BAAQMD's Russell City Energy Center analysis. The Virginia projects include the following three degradation factors: 3.4% performance margin of the combustion turbines, 1.2% degradation margin for auxiliary power, and a 7.1% degradation margin for the steam turbine system. Application of these factors yields an overall degradation factor of 12.0%, which is slightly less than the value derived at for the Russell City Energy Center.

CPV Smyth believes it is important that the GHG BACT emission rate take into account design margin, degradation of generating equipment and auxiliary power degradation, consistent with the Russell City Energy Center analysis and recent VDEQ determinations. CPV Smyth proposes a 12.0% degradation factor consistent with projects recently approved by the VDEQ.

5.2.9 Summary of Proposed Combustion Turbine BACT Emission Rates

Provided in Table 5-3 is a summary of proposed BACT emission rates for the combined cycle combustion turbines.

Table 5-3: Proposed Combustion Turbine BACT Emission Limits – Steady State Operation

Pollutant	Emission Controls	Short Term Limit(s)	Long Term Limit (per unit)
NO_x	DLN Combustors (CTs) LNB (Duct Burners) SCR	2.0 ppmvd @15% O2 (all operating modes)	74.7 tpy
CO	Good Combustion Practices Oxidation Catalyst	2.0 ppmvd @15% O2 (all operating modes)	47.7 tpy
$PM/PM_{10}/PM_{2.5}$	Good Combustion Practices Natural Gas Sole Fuel	12.9 lbs/hr (full load with duct firing) 9.4 lbs/hr (full load without duct firing) 0.005 lb/MMBtu (all operating modes)	39.5 tpy
VOC	Good Combustion Practices Oxidation Catalyst	1.0 ppmvd @15% O2 (without duct firing) 2.0 ppmvd @15% O2 (with duct firing)	22.1 tpy
H_2SO_4	Natural Gas Sole Fuel Sulfur ≤0.5 gr/100 CF gas	0.0010 lbs/MMBtu	8.6 tpy
CO_2e	Natural Gas Sole Fuel Energy Efficiency	888 lb/gross MW-hr (12-month average)	1,156,440 tpy

5.2.10 Startup/Shutdown (SU/SD) Emissions

Combustion turbines experience increased VOC, CO and NO_x emissions during startup and shutdown operation. In addition, initial low operating temperatures during startup preclude the use of the SCR and limit the efficiency of the oxidation catalyst. BACT for startup and shutdown is good operating practices by following the manufacturer's recommendations during startup, and limiting the startup time. The Alstom GT24 combustion turbines proposed for the project enables the plant to meet the proposed BACT emission rates at very low operating loads, down to approximately 5 percent CTG load (10% plant load). This design feature of the GT24 turbines reduces the number of starts and stops by allowing the units to cycle down during periods of low demand rather than requiring the unit to be shutdown.

Although the number of starts and stops will be minimized, startup and shutdown operation cannot be completely avoided. During SU/SD operation, VOC, CO and NO_x emissions will be minimized by

proper operational practices. The combustion turbines will be operated in accordance with manufacturer specifications during SU/SD periods to ensure that emissions are minimized during these short periods. Additionally, NH_3 injection will be initiated as a soon as practicable after the SCR catalyst reaches the vendor specified minimum operating temperature to minimize NO_x emissions during these periods. The estimated startup/shutdown emissions for the combustion turbines are provided in Table 5-4. Any increase in emissions during SU/SD operation is included in the potential annual emissions provided in Table 5-3; detailed emission calculations are provided in Appendix B.

Table 5-4: Transient Emission Limits (lbs per event)

Pollutant	Cold Start	Warm Start	Hot Start	Shutdown	Transition to and from LLOC
NO_x	61	56	50	4.6	2.9
CO	77	71	47	17	32
VOC	73	69	39	25	48

For the purposes of Table 5-4, the following definitions are applied:

- Cold Startup refers to restarts made at least 60 hours or more after shutdown and shall not last longer than 180 minutes per occurrence.
- Warm Startup refers to restarts made between 8 and 60 hours after shutdown and shall not last longer than 126 minutes per occurrence.
- Hot Startup refers to restarts made between 0 and 8 hours after shutdown and shall not last longer than 56 minutes per occurrence.
- Shutdown refers to the period between the time the turbine load drops below 5 percent operating load and the fuel supply to the turbine is cut. Shutdown operation shall not last longer than 11 minutes per occurrence.
- Transition to and from LLO refers to the period between LLO (5% turbine load) and compliance load and shall not last longer than 24 minutes for ramp down (12 minutes) and ramp up (12 minutes) combined.

5.3 Auxiliary Boiler

The Project will include an auxiliary boiler rated at 93 MMBtu/hr fired solely with natural gas. The auxiliary boiler will provide steam to warm up the steam turbine to minimize the duration of plant startups. Annual operation of the auxiliary boiler will be limited to a full load equivalent of 4,000 hours per year. Emissions from the boiler are subject to BACT requirements and a review was conducted of recently permitted emission rates from natural gas fired boilers; the results of this review are provided in Table 5-5. The emission limits provided in Table 5-5 serve as the basis for determining the "most stringent emissions limitation which is achieved in practice" for natural gas fired auxiliary boilers.

5.3.1 Nitrogen Oxides (NO_x)

Similar to the combustion turbines, NO_x emissions can be controlled using combustion controls and/or flue gas treatment. For the auxiliary boiler, the most advanced level of control identified in Table 5-5 is ultra LNB. Ultra LNB can achieve a NO_x emission rate of 9 ppm corrected to 3% O_2. Based upon recently permitted projects listed in Table 5-5, this is the top level of control for a gas-fired auxiliary boiler rated at less than 100 MMBtu/hr.

Further reductions in NO_x emissions could be achieved through installation of an SCR. However, the installation of an SCR on the auxiliary boiler would not be cost effective due to the already very low NOx emissions from the boiler. Potential NO_x emissions from the boiler are only 1.0 lbs/hr and limited to 2.0 tpy due to the proposed operating restriction of 4,000 hrs/yr. The VDEQ's engineering analysis for the recently permitted Brunswick Energy project, showed a cost to control of over $60,000 per ton of NO_x removed for SCR on an auxiliary boiler equipped with ultra-low NOx burners. Furthermore, the Green Energy Partners / Stonewall project was recently approved by the VDEQ with ultra-low NOx burners as lowest achievable emission rate (LAER) for the auxiliary boiler.

Based on a review of recently permitted projects, 9.0 ppm corrected to 3% O_2 was determined to be the most stringent emission limit achieved in practice and is selected as BACT for the auxiliary boiler.

5.3.2 Carbon Monoxide (CO)

CO is emitted from the auxiliary boiler as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. For the auxiliary boiler, the most advanced level of control identified in Table 5-5 is advanced ultra LNB. Ultra LNB can minimize CO emissions and achieve an emission rate of 50 ppm corrected to 3% O_2. Based upon recently permitted projects listed in Table 5-5, this is the top level of control for a gas-fired auxiliary boiler rated at less than 100 MMBtu/hr.

Further reductions in CO emissions could be achieved through installation of an oxidation catalyst. However, the installation of an oxidation catalyst on the auxiliary boiler would not be cost effective due to the already low CO emissions from the boiler. Potential CO emissions from the boiler are only 3.4 lbs/hr and limited to 6.8 tpy due to the proposed operating restriction of 4,000 hrs/yr. The VDEQ's engineering analysis for the recently permitted Brunswick Energy project, showed a cost to control of $10,000 per ton of CO removed for an oxidation catalyst on an auxiliary boiler equipped with ultra-low NO_x burners. Furthermore, the Green Energy Partners / Stonewall project concluded that an oxidation catalyst would not be cost effective on an auxiliary boiler emitting over 12 tpy, nearly double the emissions from the Project's auxiliary boiler.

Based on a review of recently permitted projects, 50 ppm corrected to 3% O_2 was determined to be the most stringent emission limit achieved in practice and is selected as BACT for the auxiliary boiler.

Table 5-5: Summary Of Recent PSD Criteria Pollutant BACT Determinations for Natural Gas-Fired Auxiliary Boilers

Facility	Location	Permit Date	Controls	Emission Limits and Controls			
				NO_x[1] (ppm)	CO[1] (ppm)	VOC[1] (lb/MMBtu)	$PM_{10}/PM_{2.5}$[2] (lb/MMBtu)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	Ultra LNB	9.0	50	0.002 (LAER)	0.002
Brunswick County Power	Freeman, VA	05/23/2012	Ultra LNB	9.0	50	0.006	0.0075
Dominion Warren County	Front Royal, VA	12/21/2010	Ultra LNB	9.0	50	0.0053	0.005
Carroll County Energy	Washington Twp., OH	11/5/2013	Ultra LNB	16.4	75	0.006	0.008
Renaissance Power	Carson City, MI	11/1/2013	LNB	30	50	0.005	0.005
Kleen Energy	Middletown, CT	07/2/2013	LNB	37	100	0.004	0.006
Oregon Clean Energy	Oregon, OH	06/18/2013	Ultra LNB	16.4	75	0.006	0.008
Hickory Run Energy	North Beaver Twp., PA	04/23/2013	Ultra LNB	9.0	50	N/A	0.005
Sunbury Generation	Sunbury, PA	04/01/2013	LNB	30	100	0.005	0.008
Hess Newark Energy	Newark, NJ	11/01/2012	Ultra LNB	9.0	50	0.004	0.005
Cricket Valley Energy Center	Middleton, NY	09/27/2012	Ultra LNB	9.0	50	0.0015 (LAER)	0.005
Pioneer Valley Energy Center	Westfield, MA	04-12-2012	LNB	25	50	N/A	0.0048
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	Ultra LNB	9.0	50	N/A	0.008
Avenal Power Center	Avenal, CA	05/27/2011	Ultra LNB	9.0	50	N/A	0.005
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	LNB	40	N/A	N/A	0.0025
Victorville 2 Hybrid	Victorville, CA	03-11-2010	Ultra LNB	9.0	50	N/A	0.003

[1] Concentration in ppm is parts per million by volume, dry, at 3 percent O_2.

[2] Concentration in pounds per million Btu heat input (HHV), except as noted, including front (filterable) and back-half (condensable) PM.

5.3.3 Volatile Organic Compounds (VOCs)

Similar to CO, VOCs are emitted from the auxiliary boiler as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. For the auxiliary boiler, the most advanced level of control identified in Table 5-5 is advanced ultra LNB. There are no technically feasible add-on control technologies that can reduce VOC emissions from the auxiliary boiler by significantly measurable amounts.

The lowest permitted VOC emission rates identified in Table 5-5 are for the Green Energy Partners / Stonewall and Cricket Valley Energy projects. However, both of these projects are located in ozone non-attainment areas and were required to meet LAER for VOC emissions. The PSD BACT determinations identified in Table 5-5 are consistently at or close to an emission rate of 0.005 lb/MMBtu. Based upon these recent PSD BACT determinations, 0.005 lb/MMBtu was determined to be BACT for the auxiliary boiler.

5.3.4 Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel, products of incomplete combustion and conversion of SO_2 in the exhaust to condensable salts. Particulate emissions from a combustion source are minimized by utilizing state of the art combustion technology while firing natural gas since natural gas has the lowest ash and sulfur content available. The permitted PM emission rates identified in Table 5-5 range from 0.002 to 0.008 lb/MMBtu, with most projects at 0.005 lb/MMBtu. The three most recent projects permitted in VA cover the full range of these permitted limits. The reason for the difference in permitted PM emission from the auxiliary boiler is most likely due to differences in vendor specified emission rates.

Based upon recent PSD BACT determinations, 0.005 lb/MMBtu was selected as BACT for the auxiliary boiler.

5.3.5 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

Sulfur dioxide and sulfuric acid mist are emitted from the auxiliary boiler as a result of the oxidation of the sulfur in the fuel. The only practical means for controlling SO_2 and H_2SO_4 emissions from the auxiliary boiler is to limit the sulfur content of the fuel. The Project proposes BACT to be the use of pipeline quality natural gas with a sulfur content no greater than 0.5 gr/100 scf of gas, or approximately 0.0014 lbs SO_2/MMBtu.

5.3.6 Greenhouse Gases

As discussed in Section 5.2.8, there are three control mechanisms for reducing GHG emissions from combustion processes: (1) low carbon-emitting fuels; (2) carbon capture and storage (CCS); and (3) energy efficiency.

The combined cycle combustion turbines account for 99% of the facility's GHG emissions. As discussed in Section 5.2.8, CCS is not technically or economically feasible for the GHG emissions from the combustion turbines. Since CCS becomes more feasible at larger scales, it is concluded that it is not feasible for the auxiliary boiler as it is not feasible for the combined cycle combustion turbines.

BACT for the auxiliary boiler is proposed to be firing natural gas as the sole fuel and efficient boiler design.

5.4 Emergency Generator and Fire Pump Engines

The Project will include an emergency diesel generator engine and a diesel fire pump engine. Both engines will be fired with ULSD fuel. Both engines will be used only during emergency situations, with the exception of periodic maintenance/readiness testing, and will be limited to a maximum of 500 operating hours per rolling 12 month period.

There are no post-combustion controls that have been demonstrated in practice for small, emergency internal combustion engines. In order to satisfy BACT requirements, CPV Smyth proposes that the engines meet NSPS 40 CFR 60 Subpart IIII requirements. Under 40 CFR 60 Subpart IIII, the emergency generator engine must meet the Tier 2 standards and the fire pump engine must meet the Tier 3 standards for off-road diesel engines under 40 CFR 89. Emissions will be controlled through the use of ULSD, engine design, good combustion practices and limited annual operation. With the exception of emergency situations, the engines will only operate for maintenance and readiness testing purposes; operation for these purposes shall be limited to 100 hours per year. The specific BACT emission limits for each engine are provided in Table 5-6.

Table 5-6: Emergency Engine Emission Standards

Pollutant	Emergency Generator Tier 2 Standard (g/kW-hr)	Fire Pump Tier 3 Standard (g/kW-hr)
NO_x	6.4[1]	4.0[2]
CO	3.5	3.5
VOC	1.3[1]	0.5[2]
$PM/PM_{10}/PM_{2.5}$	0.2	0.2
SO_2[3]	N/A	N/A

[1] Tier 2 standard for NO_x and VOC is 6.4 g/kWh, combined. To estimate potential emissions, assumed NO_x emissions equal to this level and VOC emissions equal to the older Tier 1 limit of 1.3 g/kWh.

[2] Tier 3 standard for NO_x and VOC is 6.4 g/kWh, combined. To estimate potential emissions, assumed NO_x emissions equal to this level and VOC emissions equal to 0.5 g/kWh.

[3] SO_2 emissions will be limited based upon a maximum fuel sulfur content of 15 ppm (0.0015 lb/MMBtu).

5.5 Fugitive GHG Emission Sources

The project will include natural gas handling systems and sulfur hexafluoride (SF_6) containing circuit breakers. Fugitive losses of natural gas and SF_6 will contribute to GHG emissions from the Project. At this time, the CPV Smyth does not have the design details necessary (i.e., number of natural gas pipeline connections and circuit breaker SF_6 capacity) to quantify fugitive CO_2e emissions from this equipment. Although fugitive CO_2e emissions cannot be quantified at this time, the project will implement current BACT standards for these emission sources, including the following:

- The facility will implement an auditory/visual/olfactory leak detection program for the natural gas piping components and make daily observations.
- The facility will equip the circuit breaker with a low pressure alarm and low pressure lockout. SF_6 emissions from the circuit breaker will be calculated annually (calendar year) in accordance with

the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD. The maximum annual leakage rate for SF_6 will not exceed 1% of the total SF_6 storage capacity of the plant's circuit breakers.

- The facility shall maintain records of all measurements and reports related to the fugitive emission sources including those related to maintenance as well as compliance with the Monitoring and QA/QC defined under 40 CFR 98.304 Subpart DD.

APPENDIX A

Application Forms

DOCUMENT CERTIFICATION

Facility Name: CPV Smyth Generation Company, LLC

Registration No. _____

Facility Location: Atkins, VA

Type of Submittal Attached: Major NSR Air Permit Application

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 who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Name of Responsible Official (Print): Peter Podurgiel

Title: Sr. Vice President

Signature: _____ Date: 1/30/14

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: CPV Smyth Generation Company	Registration Number:
Applicant's Name: CPV Smyth Generation Company, LLC	Name of Contact Person at the site: Gener Gotiangco
Applicant's Mailing address: 8403 Colesville Road Suite 915 Silver Spring, MD 20910	Contact Person Telephone Number: (240) 723-2307

Facility location (also attach map): The proposed Project will be constructed on a 108 acre parcel at a greenfield location in Atkins, VA. Facility site is located in east-central Smyth County, 4 miles east-northeast of Marion, VA, approximately 0.5 miles south of Interstate 81.

Facility type, and list of activities to be conducted: 700 MW combined-cycle natural gas-fired power generating facility with two combustion turbines and associated duct burners. The facility will run as a base load plant with both combustion turbines operating concurrently but the facility will have the capability of operating with a single combustion turbine. Additional plant equipment will include an auxiliary boiler, emergency generator engine, emergency fire pump engine, aqueous ammonia storage tank; air cooled condenser; and various electrical transmission and switching equipment.

The applicant is in the process of completing an application for an air pollution control permit from the Virginia Department of Environmental Quality. In accordance with § 10.1-1321.1. Title 10.1, Code of Virginia (1950), as amended, before such a permit application can be considered complete, the applicant must obtain a certification from the governing body of the county, city or town in which the facility is to be located that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§§ 15.2-2200 et seq.) of Title 15.2. The undersigned requests that an authorized representative of the local governing body sign the certification below.

Applicant's signature:	Date:

The undersigned local government representative certifies to the consistency of the proposed location and operation of the facility described above with all applicable local ordinances adopted pursuant to Chapter 22 (§§15.2-2200 et seq.) of Title 15.2. of the Code of Virginia (1950) as amended, as follows:

(Check one block)

☐ The proposed facility is **fully consistent** with all applicable local ordinances.

☐ The proposed facility is **inconsistent** with applicable local ordinances; see attached information.

Signature of authorized local government representative:	Date:
Type or print name:	Title:

County, city or town:

[THE LOCAL GOVERNMENT REPRESENTATIVE SHOULD FORWARD THE SIGNED CERTIFICATION TO THE APPROPRIATE DEQ REGIONAL OFFICE AND SEND A COPY TO THE APPLICANT.]

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: CPV Smyth Generation Company	Registration Number:
Applicant's Name: CPV Smyth Generation Company, LLC	Name of Contact Person at the site: Gener Gotiangco
Applicant's Mailing address: 8403 Colesville Road Suite 915 Silver Spring, MD 20910	Contact Person Telephone Number: (240) 723-2307

Facility location (also attach map): The proposed Project will be constructed on a 108 acre parcel at a greenfield location in Atkins, VA. Facility site is located in east-central Smyth County, 4 miles east-northeast of Marion, VA, approximately 0.5 miles south of Interstate 81.

Facility type, and list of activities to be conducted: 700 MW combined-cycle natural gas-fired power generating facility with two combustion turbines and associated duct burners. The facility will run as a base load plant with both combustion turbines operating concurrently but the facility will have the capability of operating with a single combustion turbine. Additional plant equipment will include an auxiliary boiler, emergency generator engine, emergency fire pump engine, aqueous ammonia storage tank; air cooled condenser; and various electrical transmission and switching equipment.

The applicant is in the process of completing an application for an air pollution control permit from the Virginia Department of Environmental Quality. In accordance with § 10.1-1321.1. Title 10.1, Code of Virginia (1950), as amended, before such a permit application can be considered complete, the applicant must obtain a certification from the governing body of the county, city or town in which the facility is to be located that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§§ 15.2-2200 et seq.) of Title 15.2. The undersigned requests that an authorized representative of the local governing body sign the certification below.

Applicant's signature:	Date:

The undersigned local government representative certifies to the consistency of the proposed location and operation of the facility described above with all applicable local ordinances adopted pursuant to Chapter 22 (§§15.2-2200 et seq.) of Title 15.2. of the Code of Virginia (1950) as amended, as follows:

(Check one block)

- [x] The proposed facility is **fully consistent** with all applicable local ordinances.
- [ ] The proposed facility is **inconsistent** with applicable local ordinances; see attached information.

Signature of authorized local government representative: Clegg Williams	Date: 1/29/14
Type or print name: Clegg Williams	Title: Building & Zoning Administrator
County, city or town: Smyth County	

[THE LOCAL GOVERNMENT REPRESENTATIVE SHOULD FORWARD THE SIGNED CERTIFICATION TO THE APPROPRIATE DEQ REGIONAL OFFICE AND SEND A COPY TO THE APPLICANT.]

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY – 2014 AIR PERMIT APPLICATION FEE

As of July 1, 2012, air permit applications are subject to a fee. The fee does not apply to administrative amendments or true minor sources. Applications will be considered incomplete if the proper fee is not paid and will not be processed until full payment is received. Air permit application fees are not refundable.
Fees are adjusted every January 1st for CPI. THIS FORM IS VALID JANUARY 1, 2013 TO DECEMBER 31, 2013.
Send this form and a check (or money order) payable to "Treasurer of Virginia" to:
Department of Environmental Quality
Receipts Control
P.O. Box 1104
Richmond, VA 23218

Send a copy of this form with the permit application to:
The DEQ Regional Office

Please retain a copy for your records. Any questions should be directed to the DEQ regional office to which the application will be submitted. **Unsure of your fee? Contact the Regional Air Permit Manager.**

COMPANY NAME:	**CPV Smyth Generation Company, LLC**	**FIN:**	
COMPANY REPRESENTATIVE:	**Peter Podurgiel**	**REG. NO.**	
MAILING ADDRESS:	**50 Braintree Hill Office Park Suite 300 Braintree, MA 02184**		
BUSINESS PHONE:	**(781) 848-2786**	**FAX:**	**(240) 723-2339**
FACILITY NAME:	**CPV Smyth Generation Company**		
PHYSICAL LOCATION:	**Atkins, VA**		

PERMIT ACTIVITY	**APPLICATION FEE AMOUNT**	**CHECK ONE**
Sources subject to Title V permitting requirements:		
• Major NSR permit (Articles 7, 8, 9)	$30,970	X
• Major NSR permit amendment (Articles 7, 8, 9) *	$7,226	
• State major permit (Article 6)	$15,485	
• Title V permit (Articles 1, 3)	$20,647	
• Title V permit renewal (Articles 1, 3)	$10,323	
• Title V permit modification (Articles 1, 3)	$3,613	
• Minor NSR permit (Article 6)	$1,548	
• Minor NSR amendment (Article 6) *	$774	
• State operating permit (Article 5)	$7,226	
• State operating permit amendment (Article 5) *	$3,613	
Sources subject to Synthetic Minor permitting requirements:		
• Minor NSR permit (Article 6)	$516	
• Minor NSR amendment (Article 6) *	$258	
• State operating permit (Article 5)	$1,548	
• State operating permit amendment (Article 5) *	$825	
*FEES DO NOT APPLY TO ADMINISTRATIVE AMENDMENTS		

DEQ OFFICE TO WHICH PERMIT APPLICATION WILL BE SUBMITTED (check one)

☒ SWRO/Abingdon	☐ NRO/Woodbridge	☐ PRO/Richmond	**FOR DEQ USE ONLY** **Date:** _____
☐ VRO/Harrisonburg	☐ BRRO/Lynchburg or Roanoke	☐ TRO/Virginia Beach	**DC #:** _____ **Reg. No.:** _____

Commonwealth of Virginia
Department of Environmental Quality

AIR PERMIT APPLICATION
CHECK ALL PAGES ATTACHED AND LIST ALL ATTACHED DOCUMENTS

1 Local Government Certification Form, Page 2
1 Application Fee Form, Pages 3
1 Document Certification Form, Page 1
1 General Information, Pages 5-6
1 Fuel Burning Equipment, Page 7
1 Stationary Internal Combustion Engines, Page 8
___ Incinerators,
___ Processing,
___ Inks, Coatings, Stains, and Adhesives,
___ VOC/Petroleum Storage Tanks, Pages
___ Loading Rack and Oil-Water Separators,
___ Fumigation Operations,
1 Air Pollution Control and Monitoring Equipment, Page 9
1 Air Pollution Control/Supplemental Information, Page 10
1 Stack Parameters and Fuel Data, Page 11
1 Proposed Permit Limits for Criteria Pollutants, Page 12
1 Proposed Permit Limits for Toxic Pollutants/HAPs, Page 13
1 Proposed Permit Limits for Other Reg. Pollutants, Page 14
1 Proposed Permit Limits for GHGs on Mass Basis, Page 15
1 Proposed Permit Limits for GHGs on CO_2e Basis, Page 16
___ BAE for Criteria Pollutants, Page 27
___ BAE for GHGs on Mass Basis, Page 28
___ BAE for GHGs on CO_2e Basis, Page 29
1 Operating Periods, Page 30

___ ATTACHED DOCUMENTS:
1 Map of Site Location
1 Facility Site Plan
___ Process Flow Diagram/Schematic
___ MSDS or CPDS Sheets
8 Estimated Emission Calculations
___ Stack Tests
___ Air Modeling Data
___ Confidential Information (see Instructions)
1 BACT Analysis (see Section 5)

Check added form sheets above; also indicate the number of copies of each form in blank provided.

DOCUMENT CERTIFICATION FORM

I certify under penalty of law that this document and all attachments [as noted above] 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 who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

I certify that I understand that the existence of a permit under [Article 6 of the Regulations] does not shield the source from potential enforcement of any regulation of the board governing the major NSR program and does not relieve the source of the responsibility to comply with any applicable provision of the major NSR regulations.

SIGNATURE: _____ DATE: 1-30-14

NAME: Peter Podurgiel REGISTRATION NO: _____

TITLE: Sr. Vice President COMPANY: CPV Smyth Generation Company, LLC

PHONE: (781) 848-2786 ADDRESS: 50 Braintree Hill Office Park, Suite 300

EMAIL: ppodurgiel@cpv.com Braintree, MA 02184

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9 VAC 5-20-230B and 9 VAC 5-80-1140E.

GENERAL INFORMATION

Person Completing Form: Steven Babcock	Date: 01/27/2014	Registration Number:
Company and Division Name: Tetra Tech		FIN: 95-4148514
Mailing Address: 160 Federal St., 3rd Floor Boston, MA 02110		
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: Atkins, VA		
Telephone Number:	No. of Employees:	Property Area at Site:
Person to Contact on Air Pollution Matters – Name and Title: Gener Gotiangco Vice President	Phone Number: (240) 723-2307 Fax: (240) 723-2339 Email: GGotiangco@cpv.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility:		

Reason(s) for Submission (Check all that apply):

☐ State Operating Permit

This permit is applied for pursuant to provisions of the Virginia Administrative Code, 9 VAC 5 Chapter 80, Article 5 (SOP)

☒ New Source

☐ Modification of a Source

☐ Relocation of a Source

This permit is applied for pursuant to the following provisions of the Virginia Administrative Code:

- ☐ 9 VAC 5 Chapter 80, Article 6 (Minor Sources)
- ☒ 9 VAC 5 Chapter 80, Article 8 (PSD Major Sources)
- ☐ 9 VAC 5 Chapter 80, Article 9 (Non-Attainment Major Sources)

☐ Amendment to a Permit Dated: _____ Permit Type: ☐ SOP (Art. 5) ☐ NSR (Art. 6, 8, 9)

Amendment Type:

- ☐ Administrative Amendment
- ☐ Minor Amendment
- ☐ Significant Amendment

This amendment is requested pursuant to the provisions of:

- ☐ 9 VAC 5-80-970 (Art. 5 Adm.)
- ☐ 9 VAC 5-80-980 (Art. 5 Minor)
- ☐ 9 VAC 5-80-990 (Art. 5 Sig.)
- ☐ 9 VAC 5-80-1935 (Art. 8 Adm.)
- ☐ 9 VAC 5-80-1945 (Art. 8 Minor)
- ☐ 9 VAC 5-80-1955 (Art. 8 Sig.)
- ☐ 9 VAC 5-80-1270 (Art. 6 Adm.)
- ☐ 9 VAC 5-80-1280 (Art. 6 Minor)
- ☐ 9 VAC 5-80-1290 (Art. 6 Sig.)
- ☐ 9 VAC 5-80-2210 (Art. 9 Adm.)
- ☐ 9 VAC 5-80-2220 (Art. 9 Minor)
- ☐ 9 VAC 5-80-2230 (Art. 9 Sig.)

☐ Other (specify): _____

Explanation of Permit Request (attach documents if needed):

Application for a proposed combined cycle electric generating facility required to obtain a Major NSR Air Permit subject to Prevention of Significant Deterioration requirements. This document contains a detailed description of the project and potential emission estimates for all pollutants.

GENERAL INFORMATION (CONTINUED)

For Portable Plants: NOT APPLICABLE

Is this facility designed to be portable? ☐ Yes ☒ No

- If yes, is this facility already permitted as a portable plant? ☐ Yes ☐ No Permit Date: _____

If not permitted, is this an application to be permitted as a portable plant? ☐ Yes ☐ No

If permitted as a portable facility, is this a notification of relocation? ☐ Yes ☐ No

- Describe the new location or address (include a site map): _____

- Will the portable facility be co-located with another source? ☐ Yes ☐ No Reg. No. _____
- Will the portable facility be modified or reconstructed as a result of the relocation? ☐ Yes ☐ No
- Will there be any new emissions other than those associated with the relocation? ☐ Yes ☐ No
- Is the facility suitable for the area to which it will be located? (attach documentation) ☐ Yes ☐ No

Describe the products manufactured and/or services performed at this facility:

A proposed 714 MW combined-cycle natural gas-fired power generating facility with two combustion turbines and associated duct burners. The facility will run as a base load plant with both combustion turbines operating concurrently but the facility will have the capability of operating with a single combustion turbine. Additional plant equipment will include an auxiliary boiler, emergency generator engine, emergency fire pump engine, aqueous ammonia storage tank; air cooled condenser; and various electrical transmission and switching equipment.

List the Standard Industrial Classification (SIC) Code(s) for the facility:

4	9	1	1																

List the North American Industry Classification System (NAICS) Code(s) for the facility:

2	2	1	1	1	2														

List all the facilities in Virginia under common ownership or control by the owner of this facility:

Not Applicable

Milestones: This section is to be completed if the permit application includes a new emissions unit or modification to existing operations.

Milestones*:	Starting Date:	Estimated Completion Date:
New Equipment Installation	January 2015	April 2016
Modification of Existing Process or Equipment		
Start-up Dates	May 2017	

*For new or modified installations to be constructed in phased schedule, give construction/installation starting and completion date for each phase.

FUEL BURNING EQUIPMENT: (Boilers, Turbines, Kilns, and Other External Combustion Units)

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Input Heat Capacity For Each Fuel (Million Btu/hr)	Type of Fuel	Type of Equip. (use Code A)	Usage (use Code B)	Requested Throughput* (hrs/yr OR fuel/yr)	Federal Regulations that Apply
CT1	Alstom GT24 Combustion Turbine #1			2,270 @ -10°F	Natural Gas	19	6	8,760 hrs/yr	40 CFR 60 Subpart KKKK
CT2	Alstom GT24 Combustion Turbine #2			2,270 @ -10°F	Natural Gas	19	6	8,760 hrs/yr	40 CFR 60 Subpart KKKK
DB1	Duct Burner #1 (Vogt or equivalent)			431	Natural Gas	12	6	1,259 MMCF/yr of natural gas	40 CFR 60 Subpart KKKK
DB2	Duct Burner #2 (Vogt or equivalent)			431	Natural Gas	12	6	1,259 MMCF/yr of natural gas	40 CFR 60 Subpart KKKK
AB	CB Nebraska Model NB-300D-70 Auxiliary Boiler (or equivalent)			92.4	Natural Gas	12	4	359.5 MMCF/yr of natural gas	40 CFR 60 Subpart Dc 40 CFR 63 Subpart JJJJJJ

[X] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

Code A – Equipment

BOILER TYPE:
1. Pulverized Coal - Wet Bottom
2. Pulverized Coal - Dry Bottom
3. Pulverized Coal - Cyclone Furnace
4. Circulating Fluidized Bed
5. Spreader Stoke
6. Chain or Travelling Grate Stoker
7. Underfeed Stoker
8. Hand Fired Coal
9. Oil, Tangentially Fired
10. Oil, Horizontally Fired (except rotary cup)
11. Gas, Tangentially Fired
12. Gas, Horizontally Fired
13. Wood with Flyash Reinjection
14. Wood without Flyash Reinjection
15. Other (specify) Natural Gas Heater

OTHER COMBUSTION UNITS:
16. Oven / Kiln
17. Rotary Kiln
18. Process Furnace
19. Other (specify) Combustion Turbine

Code B - Usage

1. Steam Production
2. Drying / Curing
3. Space Heating
4. Process Heat
5. Food Processing
6. Electrical Generation
7. Mechanical Work
8. Other (specify) _____

***Pick only one option for a requested throughput.**

STATIONARY INTERNAL COMBUSTION ENGINES:

Company Name: CPV Smyth Generation Company, LLC	**Date:** 01/27/2014	**Registration Number:**

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Output Brake Horsepower (bhp)	Output Electrical Power (kW)	Type of Fuel	Usage* (use Code C)	Requested Throughput** (hrs/yr OR fuel/yr)	Federal Regulations that Apply
EG	Emergency diesel fired generator engine. Make & model TBD			N/A	1,500	Diesel (15 ppmw S)	1	500 hrs/yr	40 CFR 60 Subpart IIII 40 CFR 63 Subpart ZZZZ
FP	Emergency diesel fired fire pump engine. Make & model TBD			315	N/A	Diesel (15 ppmw S)	1	500 hrs/yr	40 CFR 60 Subpart IIII 40 CFR 63 Subpart ZZZZ

[X] Estimated Emission Calculations Attached (include references of emission factors and manufacturer specifications per engine) and/or Stack Test Results if Available

Code C = Usage

1. Emergency Generator
2. Participates in Emergency Load Response Program
3. Non-Emergency Generator
4. Participates in Demand Response Program(s)
5. Other (specify) _____

***Can pick more than one option**
(i.e. 1 and 2 **OR** 3 and 4)

****Pick only one option for a requested throughput.**

AIR POLLUTION CONTROL AND MONITORING EQUIPMENT:

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Unit Ref. No.	Vent/ Stack No.	Device Ref. No.	Pollutant/Parameter	Air Pollution Control Equipment			Monitoring Instrumentation
				Manufacturer and Model No.	Type (use Code N)	Percent Efficiency (%)	Specify Type, Measured Pollutant, and Recorder Used
CT1 & DB1	1	SCR1	NOx	TBD	16	90	40 CFR 75 Compliant CEMS & DAHS for NO_x & O_2
CT1 & DB1	2	OC1	CO	TBD	11	90	40 CFR 60 Compliant CEMS & DAHS for CO
CT2 & DB2	1	SCR2	NOx	TBD	16	90	40 CFR 75 Compliant CEMS & DAHS for NO_x & O_2
CT2 & DB2	2	OC2	CO	TBD	11	90	40 CFR 60 Compliant CEMS & DAHS for CO

☐ Manufacturer Specifications Included (**To be provided once vendor is selected**)

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
17. Absorber
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
18. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
19. Condenser (specify)
20. Other:_____

AIR POLLUTION CONTROL EQUIPMENT - SUPPLEMENTAL INFORMATION:

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Device Ref. No.	Type (use Code N)	Liquid Flow Rate (gpm) (4, 5, 6, 7, 17 ,19)	Liquid Medium (4, 5, 6, 7, 17, 19)	Cleaning Method (9, 10, 17, 18)	Number of Fields (10)	Number of Sections (9, 10)	Air to Cloth Ratio (fpm) (9)	Filter Material (9)	Inlet Temp. (°F)	Regeneration Method & Cycle Time (sec) (18)	Chamber Temp. (°F) (11, 12, 14, 15)	Retention Time (sec) (11, 12, 14, 15)	Pressure Drop (inch H_2O) (3, 4, 5, 6, 7, 9, 17)
SCR1	16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	650*	N/A	650*	TBD	TBD
OC1	11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	650*	N/A	650*	TBD	TBD
SCR2	16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	650*	N/A	650*	TBD	TBD
OC2	11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	650*	N/A	650*	TBD	TBD

* Design value at steady state operation.

NOTE: Numbers listed in parenthesis in the columns above represent the Control Equipment in Code N below.

Code N = Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
18. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
19. Condenser (specify)
20. Other:_____

STACK PARAMETERS AND FUEL DATA:

Company Name:	CPV Smyth Generation Company, LLC	Date:	01/27/2014	Registration Number:

Unit Ref. No.	Vent/ Stack No.	Vent/Stack or Exhaust Data						Fuel(s) Data				
		Vent/Stack Config. (use Code O)	Vent/Stack Height (feet)	Exit Diameter (feet)	Exit Gas Velocity (ft/sec)	Exit Gas Flow Rate (acfm)	Exit Gas Temp. (°F)	Type of Fuel	Heating Value* (Btu/____)	Max. Rated Burned/hr (specify units)	Max. Sulfur %	Max. Ash %
CT1 & DB1	1	5	Determined via modeling	22	17.5-46.6	4,300,000 – 12,400,000	170 - 204	Natural Gas	1,028 Btu/ft^3 (40CFR98, Sub. C)	2,587 MMCF/hr (CT & DB)	0.0009	N/A
CT2 & DB2	2	5	Determined via modeling	22	17.5-46.6	4,300,000 – 12,400,000	170 - 204	Natural Gas	1,028 Btu/ft^3 (40CFR98, Sub. C)	2,587 MMCF/hr (CT & DB)	0.0009	N/A
AB	3	5	30	4	26.0 @ 100% load	19,580	260	Natural Gas	1,028 Btu/ft^3 (40CFR98, Sub. C)	0.090 MMCF/hr	0.0009	N/A
EG	5	5	10	1.25	150 @ 100% load	11,061	763	Diesel	138,000 Btu/gal (40CFR98, Sub. C)	104.8 gal/hr	0.0015	N/A
FP	6	5	10	0.42	171 @ 100% load	1,400	961	Diesel	138,000 Btu/gal (40CFR98, Sub. C)	15.9 gal/hr	0.0015	N/A

Code O – Vent/Stack Configuration

1. Stack discharging downward, or nearly download
2. Equivalent stack representing a combination of multiple actual stacks
3. Gooseneck stack
4. Stack discharging in a horizontal direction
5. Stack with an unobstructed opening discharge in a vertical direction
6. Vertical stack with a weather cap or equivalent obstruction in exhaust system

*** Specify units for each heating value in Btus per unit of fuel.**

PROPOSED PERMIT LIMITS FOR CRITERIA POLLUTANTS:

Company Name:	CPV Smyth Generation Company, LLC	Date:	01/27/2014	Registration Number:	

Unit Ref. No.	Proposed Permit Limits for Criteria Pollutants															
	PM [a] (Particulate Matter)		PM-10 [a,b] (10 µM or smaller particulate matter)		PM 2.5 [a,b] (2.5 µM or smaller particulate matter)		SO_2 (Sulfur Dioxide)		NO_X (Nitrogen Oxides)		CO (Carbon Monoxide)		VOC [a] (Volatile Organic Compounds)		Pb (Lead)	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT1 & DB1	12.9	39.5	12.9	39.5	12.9	39.5	3.8	13.2	19.6	74.7	11.9	47.7	6.8	22.1	N/A	N/A
CT2 & DB2	12.9	39.5	12.9	39.5	12.9	39.5	3.8	13.2	19.6	74.7	11.9	47.7	6.8	22.1	N/A	N/A
AB	0.46	0.92	0.46	0.92	0.46	0.92	0.13	0.26	1.01	2.02	3.42	6.83	0.47	0.94	N/A	N/A
EG	0.66	0.17	0.66	0.17	0.66	0.17	0.022	0.01	21.2	5.29	11.6	2.89	4.30	1.07	N/A	N/A
FP	0.10	0.03	0.10	0.03	0.10	0.03	0.003	0.001	2.07	0.52	1.81	0.45	0.26	0.06	N/A	N/A
TOTAL:	27.0	80.1	27.0	80.1	27.0	80.1	7.76	26.6	63.5	157.2	40.6	105.6	18.6	46.3		

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

[a] PM, PM-10, PM 2.5, and VOC should also be split up by component and reported under the Proposed Permit Limits for Toxic Pollutants/HAPs.

[b] PM-10 and PM 2.5 includes filterable and condensable.

PROPOSED PERMIT LIMITS FOR TOXIC POLLUTANTS/HAPS:

Company Name:	CPV Smyth Generation Company, LLC	Date:	01/27/2014	Registration Number:

Unit Ref. No.	Proposed Permit Limits for Toxic/HAP Pollutants*															
	HAP Name: Acrolein CAS #: 107028		HAP Name: Formaldehyde CAS #: 50000		HAP Name: Cadmium CAS #: 7440439		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT1	0.0145	0.064	0.250	1.09	0.0025	0.0109										
CT2	0.0145	0.064	0.250	1.09	0.0025	0.0109										
TOTAL:	0.029	0.127	0.499	2.19	0.0050	0.0219										

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Specify the name of the toxic pollutant/HAP for each Unit Ref. No. along with the respective CAS Number**: Toxic Pollutant means a pollutant on the designated list in the Form 7 Instructions document. Particulate matter and volatile organic compounds are not toxic pollutants as generic classes of substances, but individual substances within these classes may be toxic pollutants because their toxic properties or because a TLV (tm) has been established.

PROPOSED PERMIT LIMITS FOR OTHER REGULATED POLLUTANTS:

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Unit Ref. No.	Proposed Permit Limits for Other Regulated Pollutants*															
	Pollutant Name: Ammonia		Pollutant Name: Sulfuric Acid		Pollutant Name: CO_2e		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT1 & DB1	18.1	65.2	2.5	8.6	321,399	1,156,440										
CT2 & DB2	18.1	65.2	2.5	8.6	321,399	1,156,440										
AB	N/A	N/A	0.01	0.02	10,813	21,627										
EG	N/A	N/A	0.0017	0.0004	2,366	592										
FP	N/A	N/A	0.0003	0.0001	360	90										
TOTAL:	36.2	130.4	5.0	17.2	656,337	2,335,189										

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

* **Other Regulated Pollutant** include Fluorides, Sulfuric Acid Mist, Hydrogen Sulfide (H_2S), Total Reduced Sulfur (including H_2S), Reduced Sulfur Compounds (including H_2S), Municipal Waste Combustor Organics (measured as total tetra-through octa-chlorinated dibenzo-p-dioxins and dibenzofurans), Municipal

Waste Combustor Metals (measured as particulate matter), Municipal Waste Combustor Acid Gases (measured as the sum of SO_2 and HCl), and Municipal Solid Waste Landfill Emissions (measured as nonmethane organic compounds).

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON MASS BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name: CPV Smyth Generation Company, LLC	**Date:** 01/27/2014	**Registration Number:**

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on Mass Basis													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT1 & DB1	321,071	1,155,266	0.60	2.14	5.96	21.4	N/A	N/A	N/A	N/A	N/A	N/A	321,078	1,155,290
CT2 & DB2	321,071	1,155,266	0.60	2.14	5.96	21.4	N/A	N/A	N/A	N/A	N/A	N/A	321,078	1,155,290
AB	10,802	21,605	0.020	0.041	0.204	0.41	N/A	N/A	N/A	N/A	N/A	N/A	10,802	21,606
EG	2,359	590	0.019	0.0048	0.096	0.024	N/A	N/A	N/A	N/A	N/A	N/A	2,359	590
FP	359	90	0.0029	0.0007	0.015	0.0036	N/A	N/A	N/A	N/A	N/A	N/A	359	90
TOTAL:	655,662	2,332,816	1.24	4.33	12.2	43.3							655,676	2,335,189

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON CO_2 EQUIVALENT EMISSIONS (CO_2e) BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on CO_2 Equivalent Basis													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT1 & DB1	321,071	1,155,266	179	638	149	535	N/A	N/A	N/A	N/A	N/A	N/A	321,399	1,156,440
CT2 & DB2	321,071	1,155,266	179	638	149	535	N/A	N/A	N/A	N/A	N/A	N/A	321,399	1,156,440
AB	10,802	21,605	6	13	4	9	N/A	N/A	N/A	N/A	N/A	N/A	10,813	21,627
EG	2,359	590	6	1	2	0.5	N/A	N/A	N/A	N/A	N/A	N/A	2,366	592
FP	359	90	1	0.2	0.03	0.08	N/A	N/A	N/A	N/A	N/A	N/A	360	90
TOTAL:	655,662	2,332,816	371	1,290	280	1,080	N/A	N/A	N/A	N/A	N/A	N/A	656,337	2,355,189

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

OPERATING PERIODS:

Company Name: CPV Smyth Generation Company, LLC	Date: 01/27/2014	Registration Number:

Unit Ref. No.	Percent Annual Use/Throughput by Season				Normal Process/Equipment Operating Schedule			Maximum Process/Equipment Operating Schedule		
	December February	March May	June August	September November	Hours per Day	Days per Week	Weeks per Year	Hours per Day	Days per Week	Weeks per Year
CT1	25	25	25	25	24	7	52	24	7	52
CT2	25	25	25	25	24	7	52	24	7	52
DB1	25	25	25	25	24	5	25	≤ 3,000 hours per year dependent upon demand		
DB2	25	25	25	25	24	5	25	≤ 3,000 hours per year dependent upon demand		
AB	25	25	25	25	12	2	52	≤ 4,000 hours per year dependent upon demand		
EG	25	25	25	25	1	1	52	≤ 500 hours per year dependent upon duration of emergency situations		
FP	25	25	25	25	1	1	52	≤ 500 hours per year dependent upon duration of emergency situations		

Maximum Facility Operating Schedule		
Hours per Day	Days per Week	Weeks per Year
24	7	52

APPENDIX B

Emission Calculations

Summary of Facility-Wide Potential Annual Emissions
CPV Smyth Generation Company, LLC

Facility-Wide Potential Annual Emissions (TPY)

Pollutant	Unit 1 (CT & HRSG) (tpy)	Unit 2 (CT & HRSG) (tpy)	Auxiliary Boiler (tpy)	Emergency Generator (tpy)	Fire Pump (tpy)	Facility Total (tpy)
NO_x	74.7	74.7	2.02	5.29	0.52	157.2
CO	47.7	47.7	6.83	2.89	0.45	105.6
VOC	22.1	22.1	0.94	1.07	0.06	46.3
SO_2	13.2	13.2	0.26	0.005	0.001	26.6
$PM/PM_{10}/PM_{2.5}$	39.5	39.5	0.92	0.17	0.03	80.1
CO2	1,155,266	1,155,266	21,605	590	89.69	2,332,816
CH4	21.4	21.4	0.407	0.024	0.0036	43.3
N2O	2.14	2.14	0.041	0.005	0.0007	4.33
CO_2e	1,156,440	1,156,440	21,627	592	90	2,335,189
H_2SO_4	8.6	8.6	0.02	0.0004	0.0001	17.3
Lead (Pb)	4.5E-03	4.5E-03	9.1E-05	2.8E-06	4.2E-07	0.009
NH_3	65.2	65.2	N/A	N/A	N/A	130.3
Total HAPS	4.17	4.17	0.35	0.02	0.004	8.7

Vendor Emissions from Combustion Turbines & Duct Burner
CPV Smyth Generation Company, LLC

AMBIENT CONDITIONS:			100°F					90°F		
ALSTOM CASE #:	#22	#21	#8	#9	#10	#20	#19	#3	#4	#5
Number of GTs Operating	2	2	2	2	2	2	2	2	2	2
Operating Load	100%	100%	75%	50%	4%	100%	100%	75%	50%	4%
Fuel Heating Value, Btu/lb (LHV)	20,885	20,885	20,885	20,885	20885.00	20,885	20885.00	20,885	20,885	20,885
Fuel Heating Value, Btu/lb (HHV)	23,156	23,156	23,156	23,156	23156.00	23,156	23156.00	23,156	23,156	23,156
Eavporative Cooler Status	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF
Duct Burner Status	ON	OFF	OFF	OFF	OFF	ON	OFF	OFF	OFF	OFF
Chiller Status	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF
Ambient Relative Humidity, %	100	100	30	30	30.00	100	100.00	50	50	50
BAROMETRIC PRESSURE, psia	14.38	14.38	14.38	14.38	15.38	16.38	17.38	18.38	19.38	20.38
GT Heat Input (MMBtu/hr/unit, LHV)	1,827	1,827	1,200	914	355	1,827	1,827	1,245	944	363
GT Heat Input (MMBtu/hr/unit, HHV)	2,026	2,026	1,331	1,013	394.08	2,026	2025.88	1,381	1,047	402
DB Heat Input (MMBtu/hr/unit, LHV)	389	0	0	0	0.00	389	0.00	0	0	0
DB Heat Input (MMBtu/hr/unit, HHV)	431	0	0	0	0	431	0	0	0	0
Net Power (kW)	703,900	604,600	385,000	274,900	55,300	711,800	611,400	406,900	290,100	58,600
Gross Power (kW)	705,400	606,100	386,500	276,400	56800.00	713,300	612900.00	408,400	291,600	60,100
Heat Rate (Btu/kW-hr, gross)	6,967	6,685	6,887	7,333	13876.02	6,890	6610.79	6,762	7,181	13,380
HRSG STACK EXHAUST GAS										
Exhaust Flow, lb/hr	3,745,747	3,727,139	2,511,261	2,063,268	1428654.10	3,745,747	3727138.90	2,562,907	2,096,519	1,443,985
Stack Temprature, °F	182.7	204.1	178.7	174.2	195.6	178.5	195.5	175.1	170.4	193.8
O_2, Vol. %	10.00%	11.79%	11.87%	12.49%	15.97%	10.00%	11.79%	11.65%	12.28%	15.84%
CO_2, Vol. %	4.93%	4.11%	3.99%	3.71%	2.11%	4.93%	4.11%	4.05%	3.76%	2.13%
H_2O, Vol. %	10.87%	9.26%	9.80%	9.25%	6.17%	10.87%	9.26%	10.38%	9.83%	6.68%
N_2, Vol. %	73.33%	73.96%	73.45%	73.66%	74.85%	73.33%	73.96%	73.04%	73.26%	74.47%
Ar, Vol. %	0.88%	0.88%	0.88%	0.88%	0.90%	0.88%	0.88%	0.87%	0.88%	0.89%
MW, lb/lb-mole	28.22	28.32	28.25	28.28	28.48	28.22	28.32	28.19	28.23	28.43
HRSG EXHAUST STACK EMISSIONS (PER STACK):										
NOX, ppmvd @ 15% O 2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOX, lb/hr as NO2	17.8	14.7	9.7	7.4	2.9	17.8	14.7	10.0	7.6	2.9
VOC, ppmvd @ 15% O 2 as CH4	2.0	1.0	1.0	1.0	2.0	2.0	1.0	1.0	1.0	2.0
VOC, lb/hr as CH4	6.2	2.6	1.7	1.3	1.0	6.2	2.6	1.7	1.3	1.0
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
CO, lb/hr	10.8	8.9	5.9	4.5	1.7	10.8	8.9	6.1	4.6	1.8
SO2, lb/hr	3.2	2.7	1.8	1.3	0.5	3.2	2.7	1.8	1.4	0.5
H2SO4, lb/hr	2.0	1.7	1.1	0.9	0.3	2.0	1.7	1.2	0.9	0.3
H2SO4, lb/MMBtu	0.00081	0.00084	0.00083	0.00089	0.00076	0.00081	0.00084	0.00087	0.00086	0.00075
$PM/PM_{10}/PM_{2.5}$, lb/hr	12.0	7.2	8.7	8.0	2.1	12.0	7.2	9.0	8.2	2.1
$PM/PM_{10}/PM_{2.5}$, lb/MMBtu	0.0049	0.0036	0.0065	0.0079	0.0053	0.0049	0.0036	0.0065	0.0078	0.0052
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
NH_3, lb/hr	16.5	13.6	8.9	6.8	2.6	16.5	13.6	9.3	7.0	2.7
CO_2, lb/hr	292,053	240,790	158,189	120,456	46,839	292,053	240,790	164,123	124,443	47,791
CH_4, lb/hr	5.42	4.47	2.93	2.23	0.87	5.42	4.47	3.04	2.31	0.89
N_2O, lb/hr	0.54	0.45	0.29	0.22	0.09	0.54	0.45	0.30	0.23	0.09
CO_2e, lb/hr	292,350	241,035	158,350	120,579	46,887	292,350	241,035	164,290	124,569	47,839
CO_2e, lb/MW-hr (gross)	828.9	795.4	819.4	872.5	1650.9	819.7	786.5	804.6	854.4	1592.0

V[illegible]r Emissions from Combustion Turbines & Duct Burner
CPV Smyth Generation Company, LLC

AMBIENT CONDITIONS:	59°F				-10°F				
ALSTOM CASE #:	#11	#12	#13	#14	#23	#15	#16	#17	#18
Number of GTs Operating	2	2	2	2	2	2	2	2	2
Operating Load	100%	75%	50%	5%	100%	100%	75%	50%	5%
Fuel Heating Value, Btu/lb (LHV)	20,885	20,885	20,885	20,885	20,885	20,885	20,885	20,885	20,885
Fuel Heating Value, Btu/lb (HHV)	23,156	23,156	23,156	23,156	23,156	23,156	23,156	23,156	23,156
Eavporative Cooler Status	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Burner Status	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Chiller Status	OFF	OFF	OFF	OFF	ON	OFF	OFF	OFF	OFF
Ambient Relative Humidity, %	60	60	60	60	60	60	60	60	60
BAROMETRIC PRESSURE, psia	15.38	16.38	17.38	18.38		19.38	20.38	21.38	22.38
GT Heat Input (MMBtu/hr/unit, LHV)	1,775	1,347	1,013	380	2,047	2,047	1,535	1,156	404
GT Heat Input (MMBtu/hr/unit, HHV)	1,968	1,493	1,123	422	2,270	2,270	1,702	1,282	448
DB Heat Input (MMBtu/hr/unit, LHV)	0	0	0	0	389	0	0	0	0
DB Heat Input (MMBtu/hr/unit, HHV)	0	0	0	0	431	0	0	0	0
Net Power (kW)	600,500	449,100	316,800	61,300	797,700	693,700	516,600	366,900	65,000
Gross Power (kW)	602,000	450,600	318,300	62,800	799,200	695,200	518,100	368,400	66,500
Heat Rate (Btu/kW-hr, gross)	6,538	6,627	7,057	13,432	6,760	6,531	6,571	6,960	13,463
HRSG STACK EXHAUST GAS									
Exhaust Flow, lb/hr	3,655,834	2,698,747	2,184,041	1,504,290	4,110,576	4,091,969	3,016,883	2,345,388	1,575,354
Stack Temprature, °F	187.3	173.6	170.2	197.5	167.5	196.7	181.5	171.8	194.5
O_2, Vol. %	11.91%	11.67%	12.30%	16.09%	10.17%	11.82%	11.66%	11.95%	16.19%
CO_2, Vol. %	4.07%	4.18%	3.69%	2.15%	4.96%	4.21%	4.28%	4.15%	2.19%
H_2O, Vol. %	8.98%	9.20%	8.64%	5.26%	9.76%	8.29%	8.42%	8.17%	4.49%
N_2, Vol. %	74.15%	74.07%	74.28%	75.60%	74.22%	74.80%	74.74%	74.84%	76.22%
Ar, Vol. %	0.89%	0.89%	0.89%	0.90%	0.89%	0.89%	0.89%	0.89%	0.91%
MW, lb/lb-mole	28.35	28.34	28.37	28.58	28.34	28.44	28.42	28.44	28.67
HRSG EXHAUST STACK EMISSIONS (PER STACK):									
NOX, ppmvd @ 15% O 2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOX, lb/hr as NO2	14.3	10.8	8.1	3.1	19.6	16.5	12.3	9.3	3.2
VOC, ppmvd @ 15% O 2 as CH4	1.0	1.0	1.0	2.0	2.0	1.0	1.0	1.0	2.0
VOC, lb/hr as CH4	2.5	1.9	1.4	1.1	6.8	2.9	2.2	1.6	1.1
CO, ppmvd @ 15% O 2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CO, lb/hr	8.7	6.6	5.0	1.9	11.9	10.0	7.5	5.7	2.0
SO2, lb/hr	2.6	2.0	1.5	0.6	3.8	3.0	2.3	1.7	0.6
H2SO4, lb/hr	1.7	1.3	0.9	0.4	2.5	1.9	1.4	1.1	0.4
H2SO4, lb/MMBtu	0.00086	0.00087	0.00080	0.00095	0.00093	0.00084	0.00082	0.00086	0.00089
$PM/PM_{10}/PM_{2.5}$, lb/hr	7.0	9.0	8.5	2.2	12.9	8.0	9.4	9.0	2.4
$PM/PM_{10}/PM_{2.5}$, lb/MMBtu	0.0036	0.0060	0.0076	0.0052	0.0048	0.0035	0.0055	0.0070	0.0054
NH_3, ppmvd @ 15% O 2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NH_3, lb/hr	13.2	10.0	7.5	2.8	18.1	15.2	11.4	8.6	3.0
CO_2, lb/hr	233,909	177,466	133,485	50,130	321,071	269,808	202,307	152,383	53,204
CH_4, lb/hr	4.34	3.29	2.48	0.93	5.96	5.01	3.75	2.83	0.99
N_2O, lb/hr	0.43	0.33	0.25	0.09	0.60	0.50	0.38	0.28	0.10
CO_2e, lb/hr	234,147	177,647	133,621	50,181	321,397	270,082	202,513	152,538	53,258
CO_2e, lb/MW-hr (gross)	777.9	788.5	839.6	1598.1	804.3	777.0	781.8	828.1	1601.8

Summary of Annual Emissions 1/27/2014
CPV Smyth Generation Company, LLC

Startup/Shutdown Operating Data

hot starts/unit	250	number/yr	0.93	hours/event	0	Min hours downtime with event	55.8	minutes per event
warm starts/unit	0	number/yr	2.10	hours/event	8	Min hours downtime with event	125.8	minutes per event
cold starts/unit	50	number/yr	2.99	hours/event	60	Min hours downtime with event	179.5	minutes per event
Transition To/From Low Load	250	number/yr	0.40	hours/event	0	Min hours downtime with event	24.0	minutes per event
shutdowns/unit	300	number/yr	0.18	hours/event	0	Min hours downtime with event	10.7	minutes per event

Startup/Shutdown Emissions Self-Correcting Analysis

		NOx	CO	VOC
Emissions per hot start	lbs	50.0	47.0	38.8
Emissions per warm start	lbs	56.0	71.0	69.0
Emissions per cold start	lbs	61.0	77.0	73.0
Emissions per transition	lbs	2.9	32.0	48.0
Emissions per shutdown	lbs	4.6	17.0	25.0
Hot start - duration (including downtime)	hrs	0.9	0.9	0.9
Warm start - duration (including downtime)	hrs	10.1	10.1	10.1
Cold start - duration (including downtime)	hrs	63.0	63.0	63.0
Transition - duration (including downtime)	hrs	0.4	0.4	0.4
Shutdown - duration of event (include downtime	hrs	0.2	0.2	0.2
Hot start - avg hourly emissions	lb/hr	51.14	47.69	39.08
Warm start - avg hourly emissions	lb/hr	5.55	7.03	6.83
Cold start - avg hourly emissions	lb/hr	0.97	1.22	1.16
Transition - avg hourly emissions	lb/hr	4.82	33.20	48.66
Shutdown - avg hourly emissions	lb/hr	17.83	25.04	28.26
Steady state average hourly (annual)	lb/hr	16.12	9.80	3.97
Transition hourly emissions (-10°F)	lb/hr	3.20	2.00	1.10
Hot start - self correcting?	lb/hr	no	no	no
Warm start - self correcting?	lb/hr	yes	yes	no
Cold start - self correcting?	lb/hr	yes	yes	yes
Transition - self correcting?	lb/hr	yes	no	no
shutdown - self correcting?	lb/hr	no	no	no

Startup/Shutdown Potential Emissions Increase (tpy/unit)

SUSD Type	NOx	CO	VOC
Hot Start	4.07	4.40	4.08
Warm Start	-	-	0.00
Cold Start	-	-	-
Transition	-	1.17	2.23
Shutdown	0.05	0.41	0.65
TOTAL	**4.11**	**4.81**	**4.73**

Emissions From Ancillary Equipment
CPV Smyth Generation Company, LLC

Emissions from Ancillary Equipment (tpy)

Pollutant	Auxiliary Boiler	Emergency Generator	Fire Pump
	92.4 MMBtu/hr	1500 kW	235 kW
NO_x	9 ppmvd @ 3% O_2	6.4 g/BHP	4.0 g/kW
	0.011 lb/MMBtu	1.46 lb/MMBtu	0.94 lb/MMBtu
	1.010 lb/hr	21.16 lb/hr	2.07 lb/hr
	2.02 TPY	5.29 TPY	0.52 TPY
CO	50 ppmvd @ 3% O_2	3.5 g/kW	3.5 g/kW
	0.0370 lb/MMBtu	0.80 lb/MMBtu	0.82 lb/MMBtu
	3.4158 lb/hr	11.57 lb/hr	1.81 lb/hr
	6.83 TPY	2.89 TPY	0.45 TPY
VOC	12 ppmvd @ 3% O_2	1.3 g/kW	0.5 g/kW
	0.0051 lb/MMBtu	0.16 lb/MMBtu	0.10 lb/MMBtu
	0.4691 lb/hr	4.30 lb/hr	0.26 lb/hr
	0.94 TPY	1.07 TPY	0.06 TPY
$PM_{10}/PM_{2.5}$	N/A ppmvd @ 3% O_2	0.2 g/kW	0.2 g/kW
	0.005 lb/MMBtu	0.01 lb/MMBtu	0.01 lb/MMBtu
	0.4620 lb/hr	0.66 lb/hr	0.10 lb/hr
	0.92 TPY	0.17 TPY	0.03 TPY
SO_2	0.0014 lb/MMBtu	0.00 lb/MMBtu	0.00 lb/MMBtu
	0.1294 lb/hr	0.02 lb/hr	0.00 lb/hr
	0.26 TPY	0.01 TPY	0.001 TPY
H_2SO_4	0.00011 lb/MMBtu	0.00011 lb/MMBtu	0.00011 lb/MMBtu
	0.0099 lb/hr	0.00166092 lb/hr	0.00025266 lb/hr
	0.02 TPY	0.0004 TPY	0.0001 TPY
Pb	4.8E-07 lb/MMBtu	1.4E-05 lb/MMBtu	1.4E-05 lb/MMBtu
	4.5E-05 lb/hr	2.0E-04 lb/hr	0.0000308 lb/hr
	8.9E-05 TPY	5.1E-05 TPY	7.7E-06 TPY
CO_2	116.9 lb/MMBtu	163.1 lb/MMBtu	163.1 lb/MMBtu
	10,802 lb/hr	2,359 lb/hr	359 lb/hr
	21,605 TPY	590 TPY	90 TPY
CH_4	0.0022 lb/MMBtu	0.0066 lb/MMBtu	0.0066 lb/MMBtu
	0.2037 lb/hr	0.096 lb/hr	0.015 lb/hr
	0.41 TPY	0.0239 TPY	0.0036 TPY
N_2O	0.00022 lb/MMBtu	0.0013 lb/MMBtu	0.0013 lb/MMBtu
	0.0204 lb/hr	1.9E-02 lb/hr	0.0029106 lb/hr
	0.041 TPY	4.8E-03 TPY	7.3E-04 TPY
CO_2e	10,814 lb/hr	2,367 lb/hr	360 lb/hr
	21,627 TPY	592 TPY	90 TPY

NOTES:

Natural Gas SO2 emissions based upon a sulfur content of 0.5 gr/100 dscf
ULSD SO2 emissions based upon a sulfur content of 15 ppmw
Aux Boiler and Gas Heater criteria pollutant emission factors from BACT analysis
Emergency Generator criteria polluant emission factors based on Tier 2 emission standards in 40 CFR 89.
Fire Pump criteria pollutant emission factors based on post -2009 emission standards in 40 CFR 60 Subpart IIII.
H2SO4 emissions assume a 5% conversion of SO2 --> SO3 (on a molar basis)
Fuel specific CO2, CH4 and N2O emission factors from 40 CFR 98, Subpart C
Pb emission factor for ULSD from AP-42 Section 3.1

Potential HAP Emissions
CPV Smyth Generation Company, LLC

HAP	Emission Rates										Total (tpy)
	(2) CTGs		(2) HRSGs		Auxiliary Boiler		Em. Generator		Fire Pump		
	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	
Organic Compounds											
Acetaldehyde	4.00E-05	1.57E-01	4.00E-05	3.45E-02			0.00	3.64E-04	7.67E-04	1.69E-03	7.42E-01
Acrolein	6.40E-06	2.52E-02	6.40E-06	5.52E-03			0.00	1.14E-04	9.25E-05	2.04E-04	1.19E-01
Benzene	1.20E-05	4.72E-02	1.20E-05	1.04E-02	2.10E-06	1.94E-04	7.76E-04	1.12E-02	9.33E-04	2.05E-03	2.26E-01
1,3-Butadiene	4.30E-07	1.69E-03	4.30E-07	3.71E-04					3.91E-05	8.60E-05	7.99E-03
Dichlorobenzene					0.00	1.11E-04					2.22E-04
Ethylbenzene	3.20E-05	1.26E-01	3.20E-05	2.76E-02							5.93E-01
Formaldehyde	1.10E-04	4.33E-01	3.50E-04	3.02E-01	7.40E-05	6.84E-03	7.89E-05	1.14E-03	1.18E-03	2.60E-03	2.36E+00
Hexane					1.80E-03	1.66E-01					3.33E-01
Propylene oxide	2.90E-05	1.14E-01	2.90E-05	2.50E-02			0.00	5.57E-02	3.56E-03	7.83E-03	5.53E-01
Toluene	1.30E-04	5.12E-01	1.30E-04	1.12E-01	0.00	3.05E-04	0.00	4.06E-03	4.09E-04	9.00E-04	2.41E+00
Xylene	6.40E-05	2.52E-01	6.40E-05	5.52E-02			1.93E-04	2.79E-03	2.85E-04	6.27E-04	1.19E+00
PAHs											
Acenaphthene					0.00	1.66E-07	0.00	6.77E-05	1.42E-06	3.12E-06	1.80E-05
Acenaphthylene					0.00	2.22E-07	0.00	1.33E-04	5.06E-05	1.11E-04	6.16E-05
Anthracene					1.80E-09	1.66E-07	1.23E-06	1.78E-05	1.87E-06	4.11E-06	5.81E-06
Benzo(a)anthracene					0.00	1.66E-07	0.00	9.00E-06	1.68E-06	3.70E-06	3.51E-06
Benzo(a)pyrene					0.00	1.11E-07	0.00	3.72E-06	1.88E-07	4.14E-07	1.25E-06
Benzo(b)fluoranthene					1.80E-09	1.66E-07	1.11E-06	1.61E-05	9.91E-08	2.18E-07	4.40E-06
Benzo(g,h,i)perylene					1.20E-09	1.11E-07	5.56E-07	8.04E-06	4.89E-07	1.08E-06	2.50E-06
Benzo(k)fluoranthene					1.80E-09	1.66E-07	2.18E-07	3.15E-06	1.55E-07	3.41E-07	1.21E-06
Chrysene					1.80E-09	1.66E-07	1.53E-06	2.21E-05	3.53E-07	7.77E-07	6.06E-06
Dibenz(a,h)anthracene					1.20E-09	1.11E-07	3.46E-07	5.00E-06	5.83E-07	1.28E-06	1.79E-06
7,12-Dimethylbenz(a) anthracene					1.60E-08	1.48E-06					2.96E-06
Fluoranthene					2.90E-09	2.68E-07	4.03E-06	5.83E-05	7.61E-06	1.67E-05	1.93E-05
Fluorene					2.70E-09	2.49E-07	1.28E-05	1.85E-04	2.92E-05	6.42E-05	6.28E-05
Indeno(1,2,3-cd)pyrene					1.80E-09	1.66E-07	4.14E-07	5.99E-06	3.75E-07	8.25E-07	2.04E-06
3-Methylchloranthrene					1.80E-09	1.66E-07					3.33E-07
2-Methylnaphthalene					2.40E-08	2.22E-06					4.44E-06
Naphthalene	1.30E-06	5.12E-03	1.30E-06	1.12E-03	0.000	5.73E-05	0.000	1.88E-03	8.48E-05	1.87E-04	2.47E-02
Phenanthrene					1.70E-08	1.57E-06	4.08E-05	5.90E-04	2.94E-05	6.47E-05	1.67E-04
Pyrene					4.90E-09	4.53E-07	3.71E-06	5.37E-05	4.78E-06	1.05E-05	1.69E-05
TOTAL PAH	2.20E-06	8.66E-03	2.20E-06	1.90E-03	6.80E-07	6.28E-05	2.12E-04	3.07E-03	1.68E-04	3.70E-04	4.18E-02
Metals											
Arsenic	2.00E-07	7.87E-04	2.00E-07	1.73E-04	2.00E-07	1.85E-05	4.62E-08	6.68E-07	4.62E-08	1.02E-07	3.74E-03
Beryllium	1.20E-08	4.72E-05	1.20E-08	1.04E-05	1.20E-08	1.11E-06					2.25E-04
Cadmium	1.10E-06	4.33E-03	1.10E-06	9.49E-04	1.10E-06	1.02E-04	5.13E-09	7.42E-08	5.13E-09	1.13E-08	2.06E-02
Chromium	1.40E-06	5.51E-03	1.40E-06	1.21E-03	1.40E-06	1.29E-04	1.24E-05	1.79E-04	1.24E-05	2.73E-05	2.63E-02
Chromium VI	2.50E-07	9.84E-04	2.50E-07	2.16E-04	2.50E-07	2.31E-05	2.24E-06	3.24E-05	2.24E-06	4.93E-06	4.69E-03
Cobalt	8.20E-08	3.23E-04	8.20E-08	7.07E-05	8.20E-08	7.58E-06					1.53E-03
Lead	4.90E-07	1.93E-03	4.90E-07	4.23E-04	4.90E-07	4.53E-05	7.69E-07	1.11E-05	7.69E-07	1.69E-06	9.18E-03
Manganese	3.70E-07	1.46E-03	3.70E-07	3.19E-04	3.70E-07	3.42E-05	2.82E-07	4.08E-06	2.82E-07	6.20E-07	6.93E-03
Mercury	2.50E-07	9.84E-04	2.50E-07	2.16E-04	2.50E-07	2.31E-05	1.03E-08	1.49E-07	1.03E-08	2.27E-08	4.68E-03
Nickel	2.10E-06	8.27E-03	2.10E-06	1.81E-03	2.10E-06	1.94E-04	1.48E-06	2.14E-05	1.48E-06	3.26E-06	3.93E-02
Selenium	2.40E-08	9.45E-05	2.40E-08	2.07E-05	2.40E-08	2.22E-06	2.56E-07	3.70E-06	2.56E-07	5.63E-07	4.50E-04
Max. Single HAP											**2.4**

Potential HAP Emissions
CPV Smyth Generation Company, LLC

HAP	Emission Rates										Total (tpy)
	(2) CTGs		(2) HRSGs		Auxiliary Boiler		Em. Generator		Fire Pump		
	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	
Total All HAPs	**4.34E-04**	**1.71E+00**	**6.74E-04**	**5.81E-01**	**1.89E-03**	**1.74E-01**	**5.65E-03**	**8.18E-02**	**7.66E-03**	**1.69E-02**	**8.7**

Notes:

1. Blank entry indicates no emission factor reportedlin the reference cited.
2. Organic HAP emission factors for CTGs are from Table 3.1-3 of AP-42 except for formaldehyde which is based on the California Air Resources Board air toxics emission factor database. H2SO4 is based on vendor performance data. Metal HAP emission factors are from AP-42 Table 1.4-4.
3. Emission factors for the auxiliary boiler are from AP-42 Tables 1.4-3 and 1.4-4.
4. Emission factors for organics the emergency diesel generator are from AP-42 Tables 3.4-3 and 3.4-4 for the fire pump Table 3.3-2.
5. Metal emissions for the emergency generator and fire pump are based on the paper "Survey of Ultra-Trace Metals in Gas Turbine Fuels", 11th Annual International Petroleum Conference, Oct 12-15, 2004. Where trace metals were detectedlin any of 13 samples, the average result is used. Where no metals were detected in any of 13 samples, the detection limit was used.
6. Hexavalent chrome is based on 18% of the total chrome emissions per EPA 453/R-98-004a.
7. H2SO4 emissions for aux boiler, emergency generator and fire pump are based on 5% of SO2 emissions (mass basis).
8. TPY based upon the following annual operating hours: CTGs - 8,760; HRSGs - 3000; Aux Boiler - 4,000; Gas Heater - 2,000; Em. Engines - 500.

Potential VA Air Toxics Emissions
CPV Smyth Generation Company, LLC

HAP	(2) CTG Emission Rates		TLV-TWA	TLV-STEL	Emissions Threshold	Emissions Threshold	Modeling Required?	SAAC 1-Hour	SAAC Annual
	lb/hr	TPY	(mg/m^3)	(mg/m^3)	(lb/hr)	(tpy)		(ug/m^3)	(ug/m^3)
Acetaldehyde	1.82E-01	6.90E-01	180	270	8.91E+00	2.61E+01	N	N/A	N/A
Acrolein	2.91E-02	1.10E-01	0.23	0.69	2.28E-02	3.34E-02	Y	17.25	0.46
Benzene	5.45E-02	2.07E-01	32		2.11E+00	4.64	N	N/A	N/A
1,3-Butadiene	1.95E-03	7.41E-03	22		1.45E+00	3.19	N	N/A	N/A
Ethylbenzene	1.45E-01	5.52E-01	434	543	1.79E+01	6.29E+01	N	N/A	N/A
Formaldehyde	4.99E-01	1.90E+00	1.2	2.5	8.25E-02	1.74E-01	Y	62.5	2.4
Propylene oxide	1.32E-01	5.00E-01	48		3.17E+00	6.96	N	N/A	N/A
Toluene	5.90E-01	2.24E+00	377	565.00	1.86E+01	54.67	N	N/A	N/A
Xylene	2.91E-01	1.10E+00	434	651	2.15E+01	6.30E+01	N	N/A	N/A
Naphthalene	5.90E-03	2.24E-02	52	79	2.61E+00	7.54E+00	N	N/A	N/A
Arsenic	9.08E-04	3.45E-03	0.2		1.32E-02	0.03	N	N/A	N/A
Beryllium	5.45E-05	2.07E-04	0.002		1.32E-04	0.00	N	N/A	N/A
Cadmium	4.99E-03	1.90E-02	0.05		3.30E-03	7.25E-03	Y	2.5	0.1
Chromium	6.36E-03	2.41E-02	0.5		3.30E-02	7.25E-02	N	N/A	N/A
Chromium VI	1.14E-03	4.31E-03	0.05		3.30E-03	0.01	N	N/A	N/A
Cobalt	3.72E-04	1.41E-03	0.05		3.30E-03	0.01	N	N/A	N/A
Lead	2.22E-03	8.45E-03	0.15		9.90E-03	2.18E-02	N	N/A	N/A
Manganese	1.68E-03	6.38E-03	5		3.30E-01	0.73	N	N/A	N/A
Mercury	1.14E-03	4.31E-03	0.05		3.30E-03	0.01	N	N/A	N/A
Nickel	9.53E-03	3.62E-02	1		6.60E-02	1.45E-01	N	N/A	N/A
Selenium	1.09E-04	4.14E-04	0.2		1.32E-02	2.90E-02	N	N/A	N/A

APPENDIX C

Equipment Specifications and Vendor Performance Data

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1 The corrections from 'Gross Output / Efficiency' to 'Net Output / Efficiency' reflects current aux. consumption/losses for Alstom equipment only.
2 Values for Information only.
3 Gas turbine output does not include the OTC heat rejection energy.
4 Ambient Pressure: 13.56 psia
5 Air Cooled Condenser
6 CO & SCR Catalyst considered for HRSG pressure drop calculations and stack emissions
7 PM10/PM2.5 measurements per EPA Method 201/a + 202
8 Particulate Matter exhaust emissions are the net emission values, i.e. the emission contribution above those pre-existing in the ambient air. Alstom therefore reserves the right to correct for the pre-existing ambient air quality if required.
9 Particulate matter emissions are often below the detection limits of most of the measuring systems. Therefore if no particulate matter is detected within maximum 4 hours of measurement, the particulate emission is deemed to have been fulfilled.
10 Particulate Matter emission limits are valid for steady state gas turbine operating conditions and are based on a three-hour average.
11 Prior to any Particulate Matter measurements, the gas turbine must be in operation continuously for at least 8 hours at or near base load. Gas turbine inlet and exhaust system are assumed to be fully commissioned and clean condition before the measurement.
12 Particulate Matter measurements may have to be repeated in order to fulfil the particulate emissions.
13 All values are based on the following fuel composition:

Constituent	Volume (%)
Nitrogen	0.664
Carbon Dioxide	0.548
Methane	96.2274
Ethane	2.175
Propane	0.26
Butane	0.0[illegible]
Pentane	0.0[illegible]
Hexane	0.016
Heptane	0.[illegible]2
Octane	0.0006

LHV (Btu/lb)	20885
HHV (Btu/lb)	23156

Sulfur Content is 0 grains/100 SCF Fuel

14 The performance summary is based on the following case descriptions:

CASE 1	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=ON
CASE 2	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=OFF
CASE 3	2x75%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 4	2x50%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 5	2xLLOC%, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 6	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=ON
CASE 7	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=OFF
CASE 8	2x75%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 9	2x50%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 10	2xLLOC%, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 11	2x100%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 12	2x75%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 13	2x50%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 14	2xLLOC%, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 15	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 16	2x75%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF

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CASE 17	2x50%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 18	2xLLOC%; -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 19	2x100%, PO, 90F, 50% RH, CH=ON*,SF=OFF
CASE 20	2x100%, PO, 90F, 50% RH, CH=ON*, SF=ON
CASE 21	2x100%, PO, 100F, 30% RH, CH=ON*,SF=OFF
CASE 22	2x100%, PO, 100F, 30% RH, CH=ON*, SF=ON
CASE 23	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=ON

PO	Performance Optimized
LLOC	Low Load Operating Concept
RH	Relative Humidity
EC	Evaporative Cooler
HF	High Fogging
CH	Chiller
APH	Air Preheater
SF	Supplementary Firing

* Chiller ON reduces inlet temperature to 50F

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Smyth County (USA): KA24-2 (2011) MS, ACC, SF

Performance Summary

		CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10	CASE 11	CASE 12	CASE 13
		2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=ON	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=OFF	2x75%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF	2xLLOC%, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=ON	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=OFF	2x75%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2xLLOC%, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x75%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
Ambient Temperature	°F	90.0	90.0	90.0	90.0	90.0	100.0	100.0	100.0	100.0	100.0	59.0	59.0	59.0
Relative Humidity	%	50.0	50.0	50.0	50.0	50.0	30.0	30.0	30.0	30.0	30.0	60.0	60.0	60.0
Number of GTs Operating	-	2	2	2	2	2	2	2	2	2	2	2	2	2
Evap Cooler Status	-	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF	OFF
High Fogging Status	-	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF	OFF
Supplementary Firing	-	ON	OFF	OFF	OFF	OFF	ON	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Combined Cycle Performance														
Gross Output	MW	690.6	591.2	408.4	291.6	60.1	681.0	583.0	386.5	276.4	56.8	602.0	450.6	318.3
Gross Efficiency (LHV)	%	54.4	56.7	55.9	52.7	28.3	53.7	56.1	54.9	51.6	27.3	57.9	57.1	53.6
Gross Heat Rate (LHV)	Btu/kWh	6276	6017	6100	6476	12061	6350	6085	6211	6614	12509	5897	5977	6364
Net Output	MW	689.1	589.7	406.9	290.1	58.6	679.5	581.5	385.0	274.9	55.3	600.5	449.1	316.8
Net Efficiency (LHV)	%	54.25	56.56	55.73	52.42	27.58	53.62	55.93	54.72	51.31	26.56	57.72	56.90	53.36
Net Heat Rate (LHV)	Btu/kWh	6290	6032	6122	6509	12370	6364	6100	6235	6650	12848	5912	5997	6395
Gas Turbine														
GT Load %		100.0	100.0	75.0	50.0	LLOC	[illegible]	100.0	75.0	50.0	LLOC	100.0	75.0	50.0
Gross Output	MW	193.50	193.50	124.41	82.94	7.57	[illegible]	192.71	117.48	78.32	6.75	192.69	141.24	94.16
GT Heat Input (LHV)	MMBtu/hr	1778.74	1778.74	1245.42	944.31	362.65	[illegible]	1773.57	1200.39	914.06	355.43	1774.98	1346.67	1012.93
GT Heat Input (HHV)	MMBtu/hr	1972	1972	1381	1047	402	[illegible]	1966	[illegible]31	1013	394	1968	1493	1123
Exhaust Gas Temperature	°F	1136.7	1136.7	1202.0	1202.0	929.4	1136.5	1136.5	1202.0	1202.0	936.8	1119.7	1198.8	1202.0
Exhaust Gas Mass Flow	lb/hr	3509150	3509150	2562907	2096519	1443985	3506299	350[illegible]93	2511261	2063268	1428654	3655834	2698747	2184041
GT Cooler Energy	MWth	19.66	19.66	13.46	8.11	[illegible]	19.85	[illegible]9.8[illegible]	14.22	8.81	3.91	25.72	10.90	5.96
HRSG														
DB Heat Input (per/HRSG) (LHV)	MMBtu/hr	389	0	0	0	0	389	0	0	0	0	0	0	0
DB Heat Input (per/HRSG) (HHV)	MMBtu/hr	431	0	0	0	0	431	0	0	0	0	0	0	0
Stack Outlet Temperature	°F	177.0	195.8	175.1	170.4	[illegible]8.8	181.0	2[illegible]2.5	178.7	174.2	195.6	187.3	173.6	170.2
Stack Outlet Mass Flow	lb/hr	3527757.9	3509150.3	2562907.2	2096519.[illegible]	14[illegible]984.8	352[illegible]	3506292.9	2511261.0	2063268.4	1428654.1	3655833.7	2698747.1	2184041.1
Gas Side Pressure Drop	in H2O	15.4	15.4	8.4	5.5	2.4	[illegible]	15.3	8.1	5.5	2.3	16.5	9.3	6.1
Steam Turbine														
Gross Output	MW	303.6	204.2	159.5	[illegible]25.8	45.0	[illegible]5.6	197.5	151.6	119.8	43.3	216.6	168.1	130.0
Condenser Pressure	psia	2.259	1.679	1.412	[illegible]46	1.088	2.[illegible]	2.152	1.813	1.618	1.267	1.088	1.088	1.088
Stack Composition														
N2	vol %	70.71%	71.35%	73.04%	[illegible]26%	74.4[illegible]	[illegible]0.84%	71.48%	73.45%	73.66%	74.85%	74.15%	74.07%	74.28%
O2	vol %	9.05%	10.92%	[illegible]	[illegible]28%	15.8[illegible]	9.10%	10.97%	11.87%	12.49%	15.97%	11.91%	11.67%	12.30%
H2O	vol %	14.34%	12.69%	10.38%	9.83%	[illegible]	14.17%	12.51%	9.80%	9.25%	6.17%	8.98%	9.20%	8.64%
CO2	vol %	5.05%	4.19%	4.05%	3.76%	2.13%	5.05%	4.18%	3.99%	3.71%	2.11%	4.07%	4.18%	3.89%
AR	vol %	0.85%	0.85%	[illegible]87%	0.88%	[illegible]89%	0.85%	0.85%	0.88%	0.88%	0.90%	0.89%	0.89%	0.89%
Emissions Per HRSG														
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	2.0	2.0	2.0
CO	lb/hr	10.6	8.7	6.1	[illegible]	1.8	10.6	8.7	5.9	4.5	1.7	8.7	6.6	5.0
CO_2	vol %	5.1%	4.2%	4.1%	3.8%	2.1%	5.0%	4.2%	4.0%	3.7%	2.1%	4.1%	4.2%	3.9%
CO_2	lb/hr	281544	231370	162064	122953	47518	280876	230702	156227	119034	46580	230992	175217	131866
NO_x	ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x as NO_2	lb/hr	17.4	14.3	10.0	7.6	2.9	17.4	14.3	9.7	7.4	2.9	14.3	10.8	8.1
VOC (as CH4)	ppmvd @ 15% O_2	2.0	1.0	1.0	1.0	2.0	2.0	1.0	1.0	1.0	2.0	1.0	1.0	1.0
VOC	lb/hr	6.1	2.5	1.7	1.3	1.0	6.1	2.5	1.7	1.3	1.0	2.5	1.9	1.4
SO_x as SO_2	lb/hr	3.2	2.6	1.8	1.4	0.5	3.2	2.6	1.8	1.3	0.5	2.6	2.0	1.5
H_2SO_4	lb/hr	2.0	1.7	1.2	0.9	0.3	2.0	1.7	1.1	0.9	0.3	1.7	1.3	0.9
PM10 (front half) Expected	lb/hr	6.4	5.2	6.1	4.6	1.8	6.4	5.2	5.9	4.5	1.7	5.2	6.6	5.0
PM10 (back half) inc. H_2SO_4 Expected	lb/hr	5.5	1.8	2.9	3.6	0.3	5.5	1.7	2.9	3.5	0.3	1.7	2.4	3.5
$PM_{10}/PM_{2.5}$ Total	lb/hr	11.9	7.0	9.0	8.2	2.1	11.9	7.0	8.7	8.0	2.1	7.0	9.0	8.5
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
NH_3	lb/hr	16.1	13.2	9.3	7.0	2.7	16.1	13.2	8.9	6.8	2.6	13.2	10.0	7.5

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Smyth County (USA): KA24-2 (2011) MS, ACC, SF

Performance Summary

		CASE 14	CASE 15	CASE 16	CASE 17	CASE 18	CASE 19	CASE 20	CASE 21	CASE 22	CASE 23
		2xLLOC%, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x75%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2xLLOC%, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, 90F, 50% RH, CH=ON,SF=OFF	2x100%, PO, 90F, 50% RH, CH=ON, SF=ON	2x100%, PO, 100F, 30% RH, CH=ON,SF=OFF	2x100%, PO, 100F, 30% RH, CH=ON, SF=ON	2x100%, PO, -10F, 60% RH, SF=ON
Ambient Temperature	°F	59.0	-10.0	-10.0	-10.0	-10.0	90.0	90.0	100.0	100.0	-10.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	100.0	100.0	100.0	100.0	60.0
Number of GTs Operating	-	2	2	2	2	2	2	2	2	2	2
Evap Cooler Status	-	OFF	OFF	OFF	OFF	OFF	ON	ON	ON	ON	OFF
High Fogging Status	-	OFF	OFF	OFF	OFF	OFF	N/A	N/A	N/A	N/A	OFF
Supplementary Firing	-	OFF	OFF	OFF	OFF	OFF	OFF	ON	OFF	ON	ON
Combined Cycle Performance											
Gross Output	MW	62.8	695.2	518.1	368.4	66.5	612.9	713.3	606.1	705.4	799.2
Gross Efficiency (LHV)	%	28.2	57.9	57.6	54.4	28.1	57.2	54.9	56.6	54.3	56.0
Gross Heat Rate (LHV)	Btu/kWh	12118	5890	5927	6277	12146	5963	6213	6029	6282	6096
Net Output	MW	61.3	693.7	516.6	366.9	65.0	611.4	711.8	604.6	703.9	797.7
Net Efficiency (LHV)	%	27.49	57.80	57.41	54.14	27.46	57.09	54.81	56.46	54.20	55.89
Net Heat Rate (LHV)	Btu/kWh	12414	5903	5944	6303	12427	5977	6226	6044	6296	6107
Gas Turbine											
GT Load %		LLOC	100.0	75.0	50.0	LLOC	100.0	100.0	100.0	100.0	100.0
Gross Output	MW	9.75	233.77	171.69	114.46	12.25	200.63	200.63	200.63	200.63	233.77
GT Heat Input (LHV)	MMBtu/hr	380.40	2047.39	1535.17	1156.33	403.73	[illegible]	1827.19	1827.19	1827.19	2047.39
GT Heat Input (HHV)	MMBtu/hr	422	2270	1702	1282	448	2026	2026	2026	2026	2270
Exhaust Gas Temperature	°F	903.8	1103.3	1159.7	1202.0	876.8	1118.3	1118.3	1118.3	1118.3	1103.3
Exhaust Gas Mass Flow	lb/hr	1504290	4091969	3016883	2345388	1575354	3727139	3727139	3727139	3727139	4091969
GT Cooler Energy	MWth	3.53	20.24	7.07	5.20	[illegible]	24.85	24.85	24.85	24.85	20.24
HRSG											
DB Heat Input (per/HRSG) (LHV)	MMBtu/hr	0	0	0	0	0	0	389	0	389	389
DB Heat Input (per/HRSG) (HHV)	MMBtu/hr	0	0	0	0	0	0	431	0	431	431
Stack Outlet Temperature	°F	197.5	196.7	181.5	171.8	[illegible]	195.5	198.5	204.1	182.7	167.5
Stack Outlet Mass Flow	lb/hr	1504290.0	4091968.8	3016882.8	2345387.6	1575353.9	3727139.0	3745746.5	3727138.9	3745746.5	4110576.0
Gas Side Pressure Drop	in H2O	2.5	20.6	11.5	7.1	2.7	[illegible]	17.2	17.2	17.2	20.6
Steam Turbine											
Gross Output	MW	43.3	227.6	174.7	39.5	42.0	[illegible]	312.1	204.9	304.2	331.7
Condenser Pressure	psia	1.088	1.088	1.088	[illegible]	1.088	[illegible]	2.259	2.172	2.873	1.088
Stack Composition											
N2	vol %	75.60%	74.80%	74.74%	[illegible]	76.2[illegible]	[illegible]	73.33%	73.96%	73.33%	74.22%
O2	vol %	16.09%	11.82%	[illegible]	[illegible]	16.1[illegible]	11.79%	10.00%	11.79%	10.00%	10.17%
H2O	vol %	5.26%	8.29%	8.42%	8.17%	[illegible]	9.26%	10.87%	9.26%	10.87%	9.76%
CO2	vol %	2.15%	4.21%	4.28%	4.15%	2.19%	4.11%	4.93%	4.11%	4.93%	4.96%
AR	vol %	0.90%	0.89%	[illegible]	0.89%	[illegible]	0.88%	0.88%	0.88%	0.88%	0.89%
Emissions Per HRSG											
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
CO	lb/hr	1.9	10.0	7.5	[illegible]	2.0	8.9	10.8	8.9	10.8	11.9
CO_2	vol %	2.2%	4.2%	4.3%	4.1%	2.2%	4.1%	4.9%	4.1%	4.9%	5.0%
CO_2	lb/hr	49846	266395	199724	150471	52897	237767	287941	237767	287941	316602
NO_x	ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x as NO_2	lb/hr	3.1	16.5	12.3	9.3	3.2	14.7	17.8	14.7	17.8	19.6
VOC (as CH4)	ppmvd @ 15% O_2	2.0	1.0	1.0	1.0	2.0	1.0	2.0	1.0	2.0	2.0
VOC	lb/hr	1.1	2.9	2.2	1.6	1.1	2.6	6.2	2.6	6.2	6.8
SO_x as SO_2	lb/hr	0.6	3.0	2.3	1.7	0.6	2.7	3.2	2.7	3.2	3.8
H_2SO_4	lb/hr	0.4	1.9	1.4	1.1	0.4	1.7	2.0	1.7	2.0	2.5
PM10 (front half) Expected	lb/hr	1.9	6.0	7.5	5.7	2.0	5.4	6.5	5.4	6.5	7.2
PM10 (back half) inc. H_2SO_4 Expected	lb/hr	0.4	2.0	1.9	3.3	0.4	1.8	5.5	1.8	5.5	5.7
$PM_{10}/PM_{2.5}$ Total	lb/hr	2.2	8.0	9.4	9.0	2.4	7.2	12.0	7.2	12.0	12.9
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
NH_3	lb/hr	2.8	15.2	11.4	8.6	3.0	13.6	16.5	13.6	16.5	18.1

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Plant Start-Up and Shutdown Emissions

KA24-2 Smyth County

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KA24-2 (2011)

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1. Introduction

This document gives an indication of the CCPP exhaust emission per GT during cold, warm, and hot start-up conditions as well as the shutdown and low load transient operation for the Smyth County project. The start-up emissions consist from GT ignition to time when plant reaches full compliance (2 ppmvd @ 15% O2 CO and 2 ppmvd @ 15% O2 NOx), i.e., when CO & SCR catalyst are fully operational and assumes HRSG purge credit as well as evacuation of the condenser as stated in the tables provided. Start-up emissions are based on both units starting at the same time. All figures for plant start-up emissions do include estimated CO and SCR reduction.

2. Fuel Gas Composition

For the stated emissions, sulfur content considered in the fuel is 0.5 grains/100scf with the below fuel chemical composition.

Constituent	Volume (%)
Methane CH4	95.2274
Ethane C2H6	2.175
Propane C3H8	0.264
Butane C4H10	0.08
Pentane C5H12	0.013
Hexanes C6H14	0.016
Heptane C7H16	0.012
Octane C8H18	0.0006
Nitrogen N2	0.664
Carbon Dioxide CO2	0.548
TOTAL	100

LHV (Btu/lb)	20885
HHV (Btu/lb)	23156

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3. Startup Emissions Data

3.1. Normal Hot Start-Up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	60	56	54	53
Nox as NO2	lb/event	47	44	43	43
CO	lb/event	47	36	35	35
VOC as CH4	lb/event.	38.8	28	25.7	26.3
PM10/2.5 Total	lb/event	8.1	6.3	6.5	6.2
H2SO4	lb/event	1.0	0.8	0.8	0.7
Heat Consumption	MMBTU HHV	856	717	657	628

Worst-Case estimated 1-hr average exhaust flow = 1840 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150°F

3.2. Fast Hot Start-Up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Condenser Evacuation Prior to Start Initiation					
Duration	min from ign	42	40	39	38
Nox as NO2	lb/event	50	48	47	47
CO	lb/event	25	20	20	20
VOC as CH4	lb/event	17	12	11	11
PM10/2.5 Total	lb/event	6.9	5.0	6.1	4.8
H2SO4	lb/event	0.8	0.7	0.7	0.7
Heat Consumption	MMBTU HHV	815	730	694	676

Worst-Case estimated 1-hr average exhaust flow = 2150 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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3.3. Non-Spinning Reserve Start-up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Condenser Evacuation Prior to Start Initiation					
Duration	min from ign	42	40	39	38
Nox as NO2	lb/event	50	49	48	47
CO	lb/event	15	13	13	13
VOC as CH4	lb/event	7.9	6.2	5.7	5.8
PM10/2.5 Total	lb/event	7.2	5.0	6.4	4.6
H2SO4	lb/event	0.8	0.8	0.7	0.7
Heat Consumption	MMBTU HHV	851	776	731	700

Worst-Case estimated 1-hr average exhaust flow = 2400 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

3.4. Normal Warm Start-Up to Compliance (After Approx. 60 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	125	124	125	125
Nox as NO2	lb/event	56	52	50	50
CO	lb/event	71	52	50	50
VOC as CH4	lb/event	69	46	40	41
PM10/2.5 Total	lb/event	10.4	9.0	9.0	9.0
H2SO4	lb/event	1.3	1.1	1.1	1.1
Heat Consumption	MMBTU HHV	1102	977	963	945

Worst-Case estimated 1-hr average exhaust flow = 1280 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 140F

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3.5. Normal Cold Start-Up to Compliance (After Approx. 200 hours standstill)

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	183	178	179	178
Nox as NO2	lb/event	61	57	55	54
CO	lb/event	77	56	53	53
VOC as CH4	lb/event	73	48	42	44
PM10/2.5 Total	lb/event	14	12	12	12
H2SO4	lb/event	1.7	1.6	1.6	1.6
Heat Consumption	MMBTU HHV	1502	1354	1324	1299

Worst-Case estimated 1-hr average exhaust flow = 1280 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 120F

3.6. Shutdown: Minimum Emissions Load to Flameout

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	13	11	9.7	9.2
Nox as NO2	lb/event	4.6	3.5	2.9	2.7
CO	lb/event	17	10	8.9	8.9
VOC as CH4	lb/event	25	15	12	13
PM10/2.5 Total	lb/event	1.9	1.4	1.2	1.2
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	179	132	112	103

Worst-Case estimated 1-hr average exhaust flow = 1640 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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3.7. Compliance to Low Load Operation

Note: During Low Load Operation Emissions are in compliance.

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	12	9.9	8.8	8.3
Nox as NO2	lb/event	1.4	1.1	0.9	0.9
CO	lb/event	17	10	8.7	8.7
VOC as CH4	lb/event	24	15	11	13
PM10/2.5 Total	lb/event	1.8	1.3	1.2	1.1
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	168	125	106	98.3

Worst-Case estimated 1-hr average exhaust flow = 1660 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

3.8. Low Load Operation to Compliance

Note: During Low Load Operation Emissions are in compliance.

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	12	9.9	8.8	8.3
Nox as NO2	lb/event	1.5	1.1	1.0	0.9
CO	lb/event	15	10	8.4	8.4
VOC as CH4	lb/event	24	15	11	13
PM10/2.5 Total	lb/event	1.9	1.3	1.2	1.1
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	168	125	106	98.3

Worst-Case estimated 1-hr average exhaust flow = 1660 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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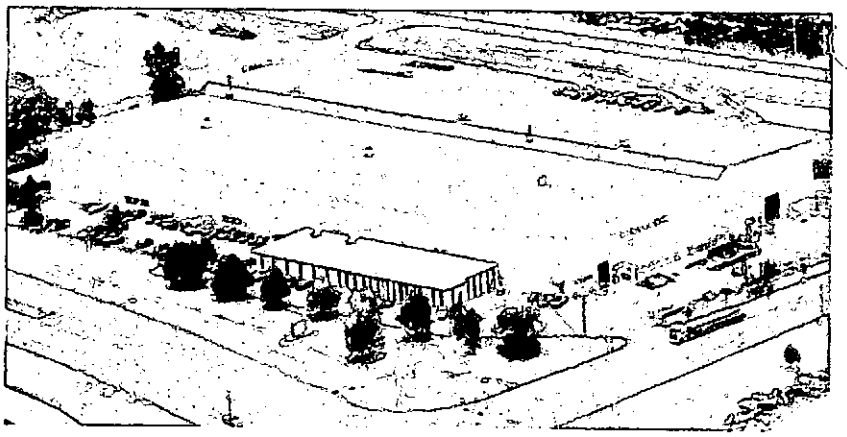
1.0 INTRODUCTION



CB Nebraska Boiler & **CB Natcom** form the engineered boiler/burner division of the **Cleaver-Brooks** family of companies. We are committed to offering integrated boiler/burner solutions to the industry. This group of companies has been in this business for more than 80 years and continues to enjoy a large percentage of the market share. We maintain our leadership in the industrial watertube market by offering innovative solutions and a true single-source responsibility to our customers for boilers, burners, controls & auxiliary equipment. This commitment to overall system design ensures that your equipment operates efficiently and lasts for years to come.

For your unique application, we are offering a packaged solution with the following design features:

1.1 OUTLET STEAM CONDITIONS:

Capacity:	77000 LB/HR ¤
Operating Pressure:	200 PSIG (at exit of non-return valve) ¤
Steam Temperature:	Saturated at 387 °F
Steam Quality:	99.5% dry steam ¤

1.2 BOILER DESIGN:

Type:	D-Type Industrial Watertube
Model:	NB-300D-70
Vessel Design Pressure:	250 psig

1.3 BURNER DESIGN:

Type:	Ultra Low-NOx Register
Main Fuel:	Natural Gas
Emissions:	9 PPM Nox

1.4 ECONOMIZER DESIGN:

Type:	Rectangular Finned-Tube
Arrangement:	Vertical Gas Flow; Counter-Current Water Flow
Design Pressure:	300 psig
Inlet Feedwater Temp:	228°F

1.5 STACK DESIGN:

Type:	Freestanding
Diameter (at exit):	78"
Height (from grade):	125 ft

3.0 BOILER DESIGN DATA

Boiler Dimensions:		**Units**
Height to Main Steam Outlet	14 Ft 7 In	FT
Overall Width of Unit	11 Ft 7.5 In	FT
Overall Length of Unit*	25.33 Ft.	FT
**Add approximately 6-8 ft length for burner.*		
Weight of Unit (Dry)	80,249.49	LBS
Weight of Unit (Wet)	102,381.53	LBS
Surface Area / Volume:		**Units**
Furnace Volume	1,379	FT3
Furnace Projected Area	819	FT2
Evaporator Area	4,277	FT2
Total Area	5,096	FT2
Economizer Area	13,317	FT2
Superheater Area	-	FT2
Tubing Data:		**Units**
Tube OD	2.0	IN
Tube Wall Thickness – Furnace Section	0.105	IN
Tube Wall Thickness – Convection Section	0.105	IN
Tube Material	SA178A	
Corrosion Allowance	NA	IN
Steam Drum:		**Units**
Inside Drum Diameter:	42 In	IN
Drum Length	25.33 Ft. Seam/Seam	FT
Drum Material:	SA516 Grade 70	
Corrosion Allowance:	NA	IN
Water Drum:		**Units**
Drum Diameter:	24 In	IN
Drum Length	25.33 Ft. Seam/Seam	FT
Drum Material:	SA106 Grade B	
Corrosion Allowance:	NA	IN
Standard Drum Connections:	**Quantity**	**Type**
Main Steam Outlet:	One	Flanged
Safety Valves:	Per ASME Code	Flanged
Feedwater Inlet:	One	Flanged
Bottom Drum Blowoff:	Two	Flanged
Water Column:	Two	Threaded (NPT)
Feedwater Regulator:	Two	Flanged
Vent:	One	NPT
Continuous Blowdown:	One	NPT
Chemical Feed:	One	NPT
Sootblower:	Two	Flanged
Auxiliary L.W. Cutouts:	One	NPT

**The above information is preliminary and shall be confirmed at time of engineering submittal.*

4.0 BOILER PERFORMANCE DATA

Fuel: Natural Gas

Boiler load - %	100%	75%	50%	25%	Units
Steam Flow - ¤	77,000	57,750	38,500	19,250	Lb/Hr
Steam Pressure – Operating - ¤	200.0	200.0	200.0	200.0	PSIG
Steam Temperature - ¤	387.0	387.0	387.0	387.0	°F
Fuel Input (HHV)	92.4	69.1	46.0	23.2	MMBTU/Hr
Ambient Air Temperature	80.0	80.0	80.0	80.0	°F
Relative Humidity	60	60	60	60	%
Excess Air	25	25	25	25	%
Flue Gas Recirculation	25	25	25	25	%
Steam Output Duty	77	58	39	19	MMBTU/hr
Heat Release Rate	67,012	50,097	33,366	16,805	BTU/FT3-Hr
Heat Release Rate	112,882	84,389	56,204	28,308	BTU/FT2-Hr
Deaerator Pegging Steam	-	-	-	-	Lb/Hr
Feed Water Temperature	227	227	227	227	°F
Water Temp. Leaving Economizer	321	309	297	288	±10°F
Blow Down	1.0	1.0	1.0	1.0	%
Boiler Gas Exit Temperature	543	498	451	409	±10°F
Economizer Gas Exit Temp.	299	282	266	251	±10°F
Air Flow	84,454	63,137	42,050	21,179	Lb/Hr
Flue Gas to Stack	88,692	66,305	44,160	22,241	Lb/Hr
Flue Gas Including FGR	110,865	82,881	55,200	27,802	Lb/Hr
Fuel Flow	4,237	3,167	2,109	1,062	Lb/Hr
Flue Gas Losses/Efficiency-%					
Dry Gas Loss	4.5	4.2	3.8	3.5	%
Air Moisture Loss	0.1	0.1	0.1	0.1	%
Fuel Moisture Loss	10.6	10.6	10.5	10.4	%
Casing Loss	0.5	0.7	1.0	2.0	%
Margin	0.5	0.5	0.5	0.5	%
Efficiency - LHV	92.8	93.1	93.2	92.5	%
Efficiency – HHV - ¤	83.7	84.0	84.1	83.5	%
Total Pressure Drop Including Economizer	9.46	5.30	2.35	0.56	IN WC
Products of Combustion - CO2	7.7	7.7	7.7	7.7	%
- H2O	16.9	16.9	16.9	16.9	%
-N2	71.7	71.7	71.7	71.7	%
-O2	3.8	3.8	3.8	3.8	%
-SO2	-	-	-	-	%
GAS- % volume	**NG**				
methane	90.00				
ethane	5.00				
nitrogen	5.00				
LHV-Btu/lb	19,687				
HHV-Btu/lb	21,815				

**The above information is preliminary and shall be confirmed at time of engineering submittal.*

DIESEL GENERATOR SET

CATERPILLAR®

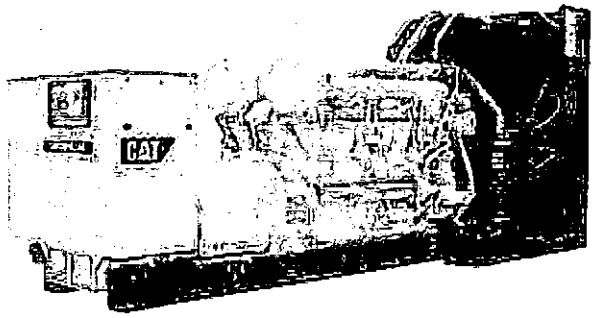


Image shown may not reflect actual package.

STANDBY
1500 ekW 1875 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 listed packages available. Certain restrictions may apply. Consult with your Cat® Dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Cat dealers provide extensive post sale support including maintenance and repair agreements
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- The Cat® S·O·S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT 3512C DIESEL ENGINE
- Reliable, rugged, durable design
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight

CAT GENERATOR
- Designed to match the performance and output characteristics of Cat diesel engines
- Single point access to accessory connections
- UL 1446 recognized Class H insulation

CAT EMCP 3 SERIES CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

SEISMIC CERTIFICATION
- Seismic Certification available
- Anchoring details are site specific, and are dependent on many factors such as generator set size, weight, and concrete strength.
  IBC Certification requires that the anchoring system used is reviewed and approved by a Professional Engineer
- Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007
- Pre-approved by OSHP and carries an OPA#(OSP-0084-01) for use in healthcare projects in California

ANDBY 1500 ekW 1875 kVA

Hz 1800 rpm 480 Volts

CATERPILLAR

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Single element canister type air cleaner with service indicator	[ ] Dual element & heavy duty air cleaners (with pre-cleaners) [ ] Air inlet adapters & shutoff
Cooling	• Radiator fan and fan drive • Fan and belt guards • Coolant level sensors* • Cat Extended Life Coolant*	[ ] Coolant level switch gauge [ ] Heat exchanger and expansion tank
Exhaust	• Exhaust manifold - dry - dual - 8 in • 203 mm (8 in) ID round flanged outlet	[ ] Mufflers [ ] Stainless steel exhaust flex fittings [ ] Elbows, flanges, expanders & Y adapters
Fuel	• Secondary fuel filters • Fuel cooler* • Fuel priming pump • Flexible fuel lines-shipped loose	[ ] Duplex secondary fuel filter [ ] Primary fuel filter with fuel water separator
Generator	• Class H insulation • Cat digital voltage regulator (CDVR) with kVAR/PF control, 3-phase sensing • Winding temperature detectors • Anti-condensation heaters • Reactive Droop	[ ] Oversize & premium generators [ ] Bearing temperature detectors
Power Termination	• Bus bar (NEMA or IEC mechanical lug holes)- right side standard • Top and bottom cable entry	[ ] Circuit breakers, UL listed, 3 pole with shunt trip,100% rated, manual or electrically operated [ ] Circuit breakers, IEC compliant, 3 or 4 pole with shunt trip, manual or electrically operated [ ] Bottom cable entry [ ] Power terminations can be located on the right, left and/or rear as an option
Governor	• ADEM™ 3	[ ] Load share module
Control Panel	• EMCP 3.1 • User interface panel (UIP) - rear mount • AC & DC customer wiring area (right side) • Emergency stop pushbutton	[ ] EMCP 3.2 ... [ ] EMCP 3.3 [ ] Option for right or left mount UIP [ ] Local & remote annunciator modules [ ] Digital I/O Module [ ] Generator temperature monitoring & protection [ ] Remote monitoring software
Lube	• Lubricating oil and filter • Oil drain line with valves • Fumes disposal • Gear type lube oil pump	[ ] Oil level regulator [ ] Deep sump oil pan [ ] Electric & air prelube pumps [ ] Manual prelube with sump pump [ ] Duplex oil filter
Mounting	• Rails - engine / generator / radiator mounting • Anti-vibration mounts (shipped loose)	[ ] Spring-type vibration isolator [ ] IBC Isolators
Starting/Charging	• 24 volt starting motor(s) • Batteries with rack and cables • Battery disconnect switch	[ ] Battery chargers (10 & 20 Amp) [ ] 45 amp charging alternator [ ] Oversize batteries [ ] Ether starting aids [ ] Heavy duty starting motors [ ] Barring device (manual) [ ] Air starting motor with control & silencer
Note	Standard and optional equipment may vary for UL 2200 Listed Packages. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.	
General	• Right hand service • Paint - Caterpillar Yellow (with high gloss black rails & radiator) • SAE standard rotation • Flywheel and flywheel housing - SAE No. 00	[ ] CSA certification [ ] CE Certificate of Conformance [ ] Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007 * Not included with packages without radiators

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SPECIFICATIONS

CAT GENERATOR

SR4B Generator
Frame Size.....697
Excitation.....Permanent Magnet
Pitch.....0.7333
Number of poles.....4
Number of bearings.....1
Number of Leads.....006
Insulation..... UL 1446 Recognized Class H with tropicalization and antiabrasion
IP Rating.....Drip Proof IP22
Alignment.....Pilot Shaft
Overspeed capability- % of rated.....150
Wave form.....003.00
Paralleling kit/Droop transformer.....Standard
Voltage Regulator3 Phase sensing with selectible volts/Hz
Telephone influence factor.....Less than 50

CAT DIESEL ENGINE

3512C ATAAC, V-12, 4 stroke, water-cooled diesel
Bore.....170.00 mm (6.69 in)
Stroke.....190.00 mm (7.48 in)
Displacement.....51.80 L (3161.03 in³)
Compression Ratio.....14.7:1
Aspiration.....TA
Fuel System..... Electronic unit injection
Governor Type.....ADEM3

CAT EMCP SERIES CONTROLS

- EMCP 3.1 (Standard)
- EMCP 3.2 / EMCP 3.3 (Option)
- Single location customer connector point
- True RMS AC metering, 3-phase
- Controls
  - Run / Auto / Stop control
  - Speed Adjust
  - Voltage Adjust
  - Emergency Stop Pushbutton
  - Engine cycle crank
- Digital Indication for:
  - RPM
  - Operating hours
  - Oil pressure
  - Coolant temperature
  - System DC volts
  - L-L volts, L-N volts, phase amps, Hz
  - ekW, kVA, kVAR, kW-hr, %kW, PF (EMCP 3.2 / 3.3)
- Shutdowns with common indicating light for:
  - Low oil pressure
  - High coolant temperature
  - Low coolant level
  - Overspeed
  - Emergency stop
  - Failure to start (overcrank)
- Programmable protective relaying functions: (EMCP 3.2 & 3.3)
  - Under and over voltage
  - Under and over frequency
  - Overcurrent (time and inverse time)
  - Reverse power (EMCP 3.3)
- MODBUS isolated data link, RS-485 half-duplex (EMCP 3.2 & 3.3)
- Options
  - Vandal door
  - Local annunciator module
  - Remote annunciator module
  - Input / Output module
  - RTD / Thermocouple modules
  - Monitoring software

STANDBY 1500 ekW 1875 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8260	
EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	1875 kVA	
Genset Power rating with fan	1500 ekW	
Coolant to aftercooler		
Coolant to aftercooler temp max	50 ° C	122 ° F
Fuel Consumption		
100% load with fan	396.9 L/hr	104.8 Gal/hr
75% load with fan	310.9 L/hr	82.1 Gal/hr
50% load with fan	219.8 L/hr	58.1 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	2075 m³/min	73278 cfm
Engine Coolant capacity with radiator/exp. tank	390.8 L	103.2 gal
Engine coolant capacity	156.8 L	41.4 gal
Radiator coolant capacity	234.0 L	61.8 gal
Inlet Air		
Combustion air inlet flow rate	129.5 m³/min	4573.3 cfm
Exhaust System		
Exhaust stack gas temperature	406.4 °C	763.5 ° F
Exhaust gas flow rate	313.2 m³/min	11060.6 cfm
Exhaust flange size (internal diameter)	203.2 mm	8.0 in
Exhaust system backpressure (maximum allowable)	6.7 kPa	26.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	616 kW	35032 Btu/min
Heat rejection to exhaust (total)	1327 kW	75466 Btu/min
Heat rejection to aftercooler	482 kW	27411 Btu/min
Heat rejection to atmosphere from engine	124 kW	7052 Btu/min
Heat rejection to atmosphere from generator	64.1 kW	3645.4 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	2670 skVA	
Frame	697	
Temperature Rise	130 ° C	234 ° F
Lube System		
Sump refill with filter	310.4 L	82.0 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	4.97 g/hp-hr	
CO g/hp-hr	.45 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.03 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

CATERPILLAR

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034-1, ISO3046, ISO8528, NEMA MG 1-22, NEMA MG 1-33, UL508A, 72/23/EEC, 98/37/EC, 2004/108/EC

Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1349 standard conditions. These ratings also apply at ISO3046 standard conditions. **Fuel rates** are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Cat representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Cat dealer.

STANDBY 1500 ekW 1875 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR

DIMENSIONS

Package Dimensions		
Length	5895.0 mm	232.09 in
Width	2537.5 mm	99.9 in
Height	2749.5 mm	108.25 in
Weight	14 035 kg	30,942 lb

NOTE: For reference only - do not use for installation design. Please contact your local dealer for exact weight and dimensions. (General Dimension Drawing #2846048).

Performance No.: DM8260

Feature Code: 512DE6C

Gen. Arr. Number: 2628100

Source: U.S. Sourced

October 27 2010

16297533

www.CAT-ElectricPower.com

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Materials and specifications are subject to change without notice. The International System of Units (SI) is used in this publication.

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CLARKE

Fire Protection Products, Inc.

Engine Selection / De-rate Calculator / Speed Interpolator

USA Purchased, USA Installed, 2011 Models, UL/FM Approved, Heat Exchanger Cooled

DATE: 2/18/2011

PUMP REQUIREMENTS:
Pump Max Power: 315 BHP
RPM(s): 1800

DERATE PARAMETERS:
Altitude: 185 (feet)
Ambient Temperature: 77 (°F)
Right Angle Gear Loss: 0%
Derate Percent: .0

APPLICATION INFO:
Customer:
Job Name:
Job Number:
Run By:

RESULTS:

Model	RPM	Rated HP (KW)	Derate HP (KW)	Emissions Tier	Interpolation Data (RPM, HP)
JU6H-UFAD98	1800	315 (235)		T3-Certified	Not used

NOTE:
Derated HP takes into account all the input derates for altitude, temperature and Right Angle Gearbox. When no derates are input, this column will be blank and engine selection(s) will be based upon Rated HP. When the Derated HP column is filled in, then the engine selection(s) are based upon this value

DEFINITIONS:

©UL/FM - Engine that is Underwriters Laboratories Listed and Factory Mutual Approved

©LPCB - Engine that is Loss Prevention Council Board Approved

©NL - Non-Listed Engine has no private agency certification, like UL, or insurance company certification, like FM. It applies to any engine that is not UL Listed or FM Approved, and is built to meet individual European country specifications

North American Offices. 3133 East Kemper Road * Cincinnati, Ohio * 45241 * USA * Tel: +1 (513) 475-3473 * Fax. +1 (513) 771-0726
European Office Grange Works * Lomond Road * Coatbridge. Scotland * ML5 2NN * Tel: +44 (0)1236 429 946 * Fax: +44 (0)1236 427 274

CLARKE

Fire Protection Products, Inc.

Exhaust Backpressure Calculator - Results
Calculations made 2/18/2011

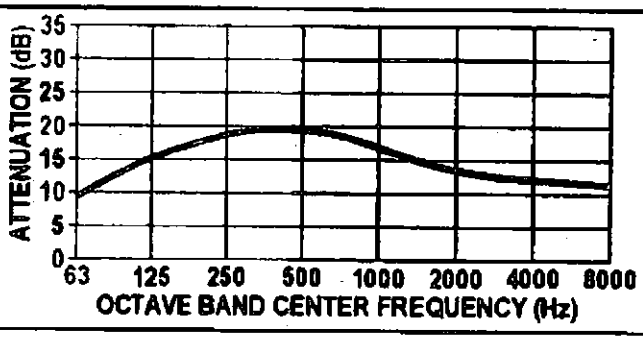
Data input by:

Input Data:

Customer:	Job Name:	Job Number:
Engine Data:	**Piping Data:**	**Silencer Data:**
Manufacturer: Clarke	Pipe Size: 5"	Manufacturer: Clarke USA
Model: JU6H-UFAD98	#90° elbow or Y:	Pipe Size (in): 5
RPM: 1760	Number 45° elbows:	Model: C06545
HP:315	Number Tees:	Application: Industrial
	Straight Pipe (Feet): 30	Connection: 150# Flange

Output Data:

Exh Flow (CFM): 1400	
Temperature (° F): 961	
Max Backpressure (inches water): 30	
Min Backpressure (inches water): 0	
Std. Exhaust Dia (in): 5	



Exhaust Pipe Recommendation:

BACKPRESSURE CALCULATIONS (Inches water)		
	6.5	Pipe
	+ 8.0	Silencer (see note 1)
	14.5	Total
	30.0	Maximum Allowable Backpressure
	Result: Total Backpressure is lower than minimum	

1) CAUTION Silencer Backpressure is based upon a Clarke USA provided Silencer. Actual Silencer Backpressure will vary depending upon the actual Silencer used (manufacturer, size, type and model). If the total Backpressure from the pipe, Silencer and orifice plate (if required) is close to the engine Maximum Allowed Backpressure, it is highly recommended you obtain the actual Backpressure (for the engine exhaust flow given above) on the Silencer being used and then confirm that the total Backpressure is still under the Maximum Allowed Backpressure.
2) Schedule 40 pipe used in calculations.
3) All pipe sizes and lengths are in inches and feet.
4) WARNING: The total Backpressure is less than the engine permissible Backpressure. In order to get the maximum Backpressure above the engine permissible limit, you must change one or more of the following: pipe size; pipe length; Silencer size, Silencer type.

North American Offices:
3133 East Kemper Road * Cincinnati, Ohio * 45241 * USA * Tel: +1 (513) 771-2200 * Fax: +1 (513) 771-0726

European Office:
Grange Works * Lomond Road * Coatbridge, Scotland * ML5 2NN * Tel. +44 (0)1236 429 946 * Fax: +44 (0)1236 427 274

Feagins, Rob (DEQ)

From: Gener Gotiangco [GGotiangco@cpv.com]
Sent: Tuesday, February 04, 2014 2:06 PM
To: Feagins, Rob (DEQ)
Cc: 'Sellars, Fred (Fred.Sellars@tetratech.com)'; Babcock, Steven
Subject: CPV Smyth - updated PSD Application transmittal
Attachments: CPV Smyth VA DEQ PSD Transmittal 02042014.pdf

Good afternoon Rob,

Please find the attached transmittal that address your comments to our January 31, 2014 CPV Smyth PSD Air Permit Application. This transmittal includes the amended Appendix A page 5 General Information and the amended Appendix C. The transmittal original is also being sent to you via hardcopy.

Thank you again for your timely review and these comments.

Feel free to advise should you have further questions or comments.

Regards,

Gener Gotiangco
Competitive Power Ventures, Inc.
8403 Colesville Road
Suite 915
Silver Spring, MD 20910
Office: (240) 723-2307
Cell: (301) 346-5738
Fax: (240) 723-2339

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Competitive
Power Ventures, Inc.

February 4, 2014

Virginia Department of Environmental Quality
Attention: Rob Feagins, Air Permit Manager
Southwest Regional Office
355-A Deadmore Street
Abingdon, Virginia 24210

RE: CPV Smyth Generation Company, LLC Prevention of Significant Deterioration Air Permit Application – updated

Dear Mr. Feagins,

In response to your February 3, 2014 communication requesting a correction and clarification to CPV Smyth's referenced Air Permit application, please find enclosed for your use and retention with the original submittal the following:

Appendix A to application, Page 5 of Form 7 updating the General Information with the correct entity and contact (1 sheet).

Appendix C Equipment Specifications and Vendor Performance Data, revised to remove "Confidentiality" notation as the major equipment supplier, Alstom, has withdrawn its request to seek confidentiality for their emissions and performance information (23 sheets).

Should you have further questions or clarifications, please do not hesitate to contact me at your convenience.

Sincerely,

Gener G. Gotiangco, P.E.
ggotiangco@cpv.com
240-723-2307

cc: M. Kiss, VA DEQ (via email)
F. Sellars, Tetra Tech (via e-mail)
R. Burke, Competitive Power Ventures, Inc. (via e-mail)

GENERAL INFORMATION

Person Completing Form: Gener Gotiangco	Date: 01/27/2014	Registration Number:
Company and Division Name: CPV Smyth Generation Company, LLC		FIN: 52-2306411
Mailing Address: 8403 Colesville Road, Suite 915 Silver Spring, MD 20910		
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: Atkins, VA		
Telephone Number:	No. of Employees:	Property Area at Site:
Person to Contact on Air Pollution Matters – Name and Title: Gener Gotiangco Vice President	Phone Number: (240) 723-2307 Fax: (240) 723-2339 Email: GGotiangco@cpv.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility:		

Reason(s) for Submission (Check all that apply):

☐ State Operating Permit

This permit is applied for pursuant to provisions of the Virginia Administrative Code, 9 VAC 5 Chapter 80, Article 5 (SOP)

☒ New Source

☐ Modification of a Source

☐ Relocation of a Source

This permit is applied for pursuant to the following provisions of the Virginia Administrative Code:

- ☐ 9 VAC 5 Chapter 80, Article 6 (Minor Sources)
- ☒ 9 VAC 5 Chapter 80, Article 8 (PSD Major Sources)
- ☐ 9 VAC 5 Chapter 80, Article 9 (Non-Attainment Major Sources)

☐ Amendment to a Permit Dated: _____ Permit Type: ☐ SOP (Art. 5) ☐ NSR (Art. 6, 8, 9)

Amendment Type:

- ☐ Administrative Amendment
- ☐ Minor Amendment
- ☐ Significant Amendment

This amendment is requested pursuant to the provisions of:

- ☐ 9 VAC 5-80-970 (Art. 5 Adm.)
- ☐ 9 VAC 5-80-980 (Art. 5 Minor)
- ☐ 9 VAC 5-80-990 (Art. 5 Sig.)
- ☐ 9 VAC 5-80-1935 (Art. 8 Adm.)
- ☐ 9 VAC 5-80-1945 (Art. 8 Minor)
- ☐ 9 VAC 5-80-1955 (Art. 8 Sig.)
- ☐ 9 VAC 5-80-1270 (Art. 6 Adm.)
- ☐ 9 VAC 5-80-1280 (Art. 6 Minor)
- ☐ 9 VAC 5-80-1290 (Art. 6 Sig.)
- ☐ 9 VAC 5-80-2210 (Art. 9 Adm.)
- ☐ 9 VAC 5-80-2220 (Art. 9 Minor)
- ☐ 9 VAC 5-80-2230 (Art. 9 Sig.)

☐ Other (specify): _____

Explanation of Permit Request (attach documents if needed):

Application for a proposed combined cycle electric generating facility required to obtain a Major NSR Air Permit subject to Prevention of Significant Deterioration requirements. This document contains a detailed description of the project and potential emission estimates for all pollutants.

APPENDIX C

Equipment Specifications and Vendor Performance Data

1 The corrections from 'Gross Output / Efficiency' to 'Net Output / Efficiency' reflects current aux. consumption/losses for Alstom equipment only.
2 Values for Information only.
3 Gas turbine output does not include the OTC heat rejection energy.
4 Ambient Pressure: 13.56 psia
5 Air Cooled Condenser
6 CO & SCR Catalyst considered for HRSG pressure drop calculations and stack emissions
7 PM10/PM2.5 measurements per EPA Method 201/a + 202
8 Particulate Matter exhaust emissions are the net emission values, i.e. the emission contribution above those pre-existing in the ambient air. Alstom therefore reserves the right to correct for the pre-existing ambient air quality if required.
9 Particulate matter emissions are often below the detection limits of most of the measuring systems. Therefore if no particulate matter is detected within maximum 4 hours of measurement, the particulate emission is deemed to have been fulfilled.
10 Particulate Matter emission limits are valid for steady state gas turbine operating conditions and are based on a three-hour average.
11 Prior to any Particulate Matter measurements, the gas turbine must be in operation continuously for at least 8 hours at or near base load. Gas turbine inlet and exhaust system are assumed to be fully commissioned and clean condition before the measurement.
12 Particulate Matter measurements may have to be repeated in order to fullfil the particulate emissions.
13 All values are based on the following fuel composition:

Constituent	Volume (%)
Nitrogen	0.664
Carbon Dioxide	0.548
Methane	96.2274
Ethane	2.175
Propane	0.264
Butane	0.08
Pentane	0.013
Hexane	0.016
Heptane	0.012
Octane	0.0006

Sulfur Content is 0.5 grains/100 SCF Fuel

LHV (Btu/lb)	20885
HHV (Btu/lb)	23156

14 The performance summary is based on the following case descriptions:

CASE 1	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=ON
CASE 2	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=OFF
CASE 3	2x75%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 4	2x50%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 5	2xLLOC%, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF
CASE 6	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=ON
CASE 7	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=OFF
CASE 8	2x75%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 9	2x50%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 10	2xLLOC%, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF
CASE 11	2x100%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 12	2x75%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 13	2x50%, PO, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 14	2xLLOC%, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF
CASE 15	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 16	2x75%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF

CASE 17	2x50%, PO, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 18	2xLLOC%, -10F, 60% RH, EC=OFF, HF=OFF, APH=ON, SF=OFF
CASE 19	2x100%, PO, 90F, 50% RH, CH=ON*,SF=OFF
CASE 20	2x100%, PO, 90F, 50% RH, CH=ON*, SF=ON
CASE 21	2x100%, PO, 100F, 30% RH, CH=ON*,SF=OFF
CASE 22	2x100%, PO, 100F, 30% RH, CH=ON*, SF=ON
CASE 23	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=ON

PO	Performance Optimized
LLOC	Low Load Operating Concept
RH	Relative Humidity
EC	Evaporative Cooler
HF	High Fogging
CH	Chiller
APH	Air Preheater
SF	Supplementary Firing

* Chiller ON reduces inlet temperature to 50F

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	0%, PO, 90F, 50% RH, EC+HF=ON, SF=ON	2x100%, PO, 90F, 50% RH, EC+HF=ON, SF=OFF	2x75%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, 90F, 50% RH, EC=OFF, HF=OFF, SF=OFF	2xLLOC%, 90. RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=ON	2x100%, PO, 100F, 30% RH, EC+HF=ON, SF=OFF	2x75%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, 100F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2xLL 00F, 30% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, P 60% RH, E HF=OFF, S
°F	90.0	90.0	90.0	90.0	90.0	100.0	100.0	100.0	100.0	100.0	59.0
%	50.0	50.0	50.0	50.0	50.0	30.0	30.0	30.0	30.0	30.0	60.0
-	2	2	2	2	2	2	2	2	2	2	2
-	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF
-	ON	ON	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF
-	ON	OFF	OFF	OFF	OFF	ON	OFF	OFF	OFF	OFF	OFF
MW	690.6	591.2	408.4	291.6	60.1	681.0	583.0	386.5	276.4	56.8	602.0
%	54.4	56.7	55.9	52.7	28.3	53.7	56.1	54.9	51.6	27.3	57.9
Btu/kWh	6276	6017	6100	6476	12061	6350	6085	6211	6614	12509	5897
MW	689.1	589.7	406.9	290.1	58.6	679.5	581.5	385.0	274.9	55.3	600.5
%	54.25	56.56	55.73	52.42	27.58	53.62	55.93	54.72	51.31	26.56	57.7
Btu/kWh	6290	6032	6122	6509	12370	6364	6100	6235	6650	12848	5912
	100.0	100.0	75.0	50.0	LLOC	100.0	100.0	75.0	50.0	LLOC	100.0
MW	193.50	193.50	124.41	82.94	7.57	192.71	192.71	117.48	78.32	6.75	192.6
MMBtu/hr	1778.74	1778.74	1245.42	944.31	362.65	1773.57	1773.57	1200.39	914.06	355.43	1774.9
MMBtu/hr	1972	1972	1381	1047	402	1966	1966	1331	1013	394	1968
°F	1136.7	1136.7	1202.0	1202.0	929.4	1136.5	1136.5	1202.0	1202.0	936.8	1119.
lb/hr	3509150	3509150	2562907	2096519	1443985	3506293	3506293	2511261	2063268	1428654	365583
MWth	19.66	19.66	13.46	8.11	3.81	19.85	19.85	14.22	8.81	3.91	25.7
MMBtu/hr	389	0	0	0	0	389	0	0	0	0	0
MMBtu/hr	431	0	0	0	0	431	0	0	0	0	0
°F	177.0	195.8	175.1	170.4	193.8	181.0	202.5	178.7	174.2	195.6	187.3
lb/hr	3527757.9	3509150.3	2562907.2	2096519.0	1443984.8	3524900.5	3506292.9	2511261.0	2063268.4	1428654.1	365583
in H2O	15.4	15.4	8.4	5.6	2.4	15.3	15.3	8.1	5.5	2.3	16.5
MW	303.6	204.2	159.5	125.8	45.0	295.6	197.5	151.6	119.8	43.3	216.6
psia	2.259	1.679	1.412	1.246	1.088	2.871	2.152	1.813	1.618	1.267	1.088
vol %	70.71%	71.35%	73.04%	73.26%	74.47%	70.84%	71.48%	73.45%	73.66%	74.85%	74.15
vol %	9.05%	10.92%	11.65%	12.28%	15.84%	9.10%	10.97%	11.87%	12.49%	15.97%	11.91
vol %	14.34%	12.69%	10.38%	9.83%	6.68%	14.17%	12.51%	9.80%	9.25%	6.17%	8.989
vol %	5.05%	4.19%	4.05%	3.76%	2.13%	5.05%	4.18%	3.99%	3.71%	2.11%	4.079
vol %	0.85%	0.85%	0.87%	0.88%	0.89%	0.85%	0.85%	0.88%	0.88%	0.90%	0.899
ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
lb/hr	10.6	8.7	6.1	4.6	1.8	10.6	8.7	5.9	4.5	1.7	8.7
vol %	5.1%	4.2%	4.1%	3.8%	2.1%	5.0%	4.2%	4.0%	3.7%	2.1%	4.1%
lb/hr	281544	231370	162064	122953	47518	280876	230702	156227	119034	46580	23099
ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
lb/hr	17.4	14.3	10.0	7.6	2.9	17.4	14.3	9.7	7.4	2.9	14.3
ppmvd @ 15% O_2	2.0	1.0	1.0	1.0	2.0	2.0	1.0	1.0	1.0	2.0	1.0
lb/hr	6.1	2.5	1.7	1.3	1.0	6.1	2.5	1.7	1.3	1.0	2.5
lb/hr	3.2	2.6	1.8	1.4	0.5	3.2	2.6	1.8	1.3	0.5	2.6
lb/hr	2.0	1.7	1.2	0.9	0.3	2.0	1.7	1.1	0.9	0.3	1.7
lb/hr	6.4	5.2	6.1	4.6	1.8	6.4	5.2	5.9	4.5	1.7	5.2
lb/hr	5.5	1.8	2.9	3.6	0.3	5.5	1.7	2.9	3.5	0.3	1.7
lb/hr	11.9	7.0	9.0	8.2	2.1	11.9	7.0	8.7	8.0	2.1	7.0
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
lb/hr	16.1	13.2	9.3	7.0	2.7	16.1	13.2	8.9	6.8	2.6	13.2

	C%, 59F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x75%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2x50%, PO, -10F, 60% RH, EC=OFF, HF=OFF, SF=OFF	2xLLOC%, -10 RH, EC=OFF, HF=OFF, SF=OFF	2x100%, PO, 90F, 50% RH, CH=ON,SF=OFF	2x100%, PO, 90F, 50% RH, CH=ON, SF=ON	2x100%, PO, 100F, 30% RH, CH=ON,SF=OFF	2x100%, PO, 100F, 30% RH, CH=ON, SF=ON	2x100%, PO, -10F, 60% RH, SF=ON
°F	59.0	-10.0	-10.0	-10.0	-10.0	90.0	90.0	100.0	100.0	-10.0
%	60.0	60.0	60.0	60.0	60.0	100.0	100.0	100.0	100.0	60.0
-	2	2	2	2	2	2	2	2	2	2
-	OFF	OFF	OFF	OFF	OFF	ON	ON	ON	ON	OFF
-	OFF	OFF	OFF	OFF	OFF	N/A	N/A	N/A	N/A	OFF
-	OFF	OFF	OFF	OFF	OFF	OFF	ON	OFF	ON	ON
MW	62.8	695.2	518.1	368.4	66.5	612.9	713.3	606.1	705.4	799.2
%	28.2	57.9	57.6	54.4	28.1	57.2	54.9	56.6	54.3	56.0
Btu/kWh	12118	5890	5927	6277	12146	5963	6213	6029	6282	6096
MW	61.3	693.7	516.6	366.9	65.0	611.4	711.8	604.6	703.9	797.7
%	27.49	57.80	57.41	54.14	27.46	57.09	54.81	56.46	54.20	55.89
Btu/kWh	12414	5903	5944	6303	12427	5977	6226	6044	6296	6107
	LLOC	100.0	75.0	50.0	LLOC	100.0	100.0	100.0	100.0	100.0
MW	9.75	233.77	171.69	114.46	12.25	200.63	200.63	200.63	200.63	233.77
MMBtu/hr	380.40	2047.39	1535.17	1156.33	403.73	1827.19	1827.19	1827.19	1827.19	2047.39
MMBtu/hr	422	2270	1702	1282	448	2026	2026	2026	2026	2270
°F	903.8	1103.3	1159.7	1202.0	876.8	1118.3	1118.3	1118.3	1118.3	1103.3
lb/hr	1504290	4091969	3016883	2345388	1575354	3727139	3727139	3727139	3727139	4091969
MWth	3.53	20.24	7.07	5.20	3.19	24.85	24.85	24.85	24.85	20.24
MMBtu/hr	0	0	0	0	0	0	389	0	389	389
MMBtu/hr	0	0	0	0	0	0	431	0	431	431
°F	197.5	196.7	181.5	171.8	194.5	195.5	178.5	204.1	182.7	167.5
lb/hr	1504290.0	4091968.8	3016882.8	2345387.6	1575353.9	3727138.9	3745746.5	3727138.9	3745746.5	4110576.0
in H2O	2.5	20.6	11.5	7.1	2.7	17.2	17.2	17.2	17.2	20.6
MW	43.3	227.6	174.7	139.5	42.0	211.6	312.1	204.9	304.2	331.7
psia	1.088	1.088	1.088	1.088	1.088	1.698	2.259	2.172	2.873	1.088
vol %	75.60%	74.80%	74.74%	74.84%	76.22%	73.96%	73.33%	73.96%	73.33%	74.22%
vol %	16.09%	11.82%	11.66%	11.95%	16.19%	11.79%	10.00%	11.79%	10.00%	10.17%
vol %	5.26%	8.29%	8.42%	8.17%	4.49%	9.26%	10.87%	9.26%	10.87%	9.76%
vol %	2.15%	4.21%	4.28%	4.15%	2.19%	4.11%	4.93%	4.11%	4.93%	4.96%
vol %	0.90%	0.89%	0.89%	0.89%	0.91%	0.88%	0.88%	0.88%	0.88%	0.89%
ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
lb/hr	1.9	10.0	7.5	5.7	2.0	8.9	10.8	8.9	10.8	11.9
vol %	2.2%	4.2%	4.3%	4.1%	2.2%	4.1%	4.9%	4.1%	4.9%	5.0%
lb/hr	49846	266395	199724	150471	52897	237767	287941	237767	287941	316602
ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
lb/hr	3.1	16.5	12.3	9.3	3.2	14.7	17.8	14.7	17.8	19.6
ppmvd @ 15% O_2	2.0	1.0	1.0	1.0	2.0	1.0	2.0	1.0	2.0	2.0
lb/hr	1.1	2.9	2.2	1.6	1.1	2.6	6.2	2.6	6.2	6.8
lb/hr	0.6	3.0	2.3	1.7	0.6	2.7	3.2	2.7	3.2	3.8
lb/hr	0.4	1.9	1.4	1.1	0.4	1.7	2.0	1.7	2.0	2.5
lb/hr	1.9	6.0	7.5	5.7	2.0	5.4	6.5	5.4	6.5	7.2
lb/hr	0.4	2.0	1.9	3.3	0.4	1.8	5.5	1.8	5.5	5.7
lb/hr	2.2	8.0	9.4	9.0	2.4	7.2	12.0	7.2	12.0	12.9
ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
lb/hr	2.8	15.2	11.4	8.6	3.0	13.6	16.5	13.6	16.5	18.1

Plant Start-Up and Shutdown Emissions

KA24-2 Smyth County

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1. Introduction

This document gives an indication of the CCPP exhaust emission per GT during cold, warm, and hot start-up conditions as well as the shutdown and low load transient operation for the Smyth County project. The start-up emissions consist from GT ignition to time when plant reaches full compliance (2 ppmvd @ 15% O2 CO and 2 ppmvd @ 15% O2 NOx), i.e., when CO & SCR catalyst are fully operational and assumes HRSG purge credit as well as evacuation of the condenser as stated in the tables provided. Start-up emissions are based on both units starting at the same time. All figures for plant start-up emissions do include estimated CO and SCR reduction.

2. Fuel Gas Composition

For the stated emissions, sulfur content considered in the fuel is 0.5 grains/100scf with the below fuel chemical composition.

Constituent	Volume (%)
Methane CH4	96.2274
Ethane C2H6	2.175
Propane C3H8	0.264
Butane C4H10	0.08
Pentane C5H12	0.013
Hexanes C6H14	0.016
Heptane C7H16	0.012
Octane C8H18	0.0006
Nitrogen N2	0.664
Carbon Dioxide CO2	0.548
TOTAL	100

LHV (Btu/lb)	20885
HHV (Btu/lb)	23156

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3. Startup Emissions Data

3.1. Normal Hot Start-Up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	60	56	54	53
Nox as NO2	lb/event	47	44	43	43
CO	lb/event	47	36	35	35
VOC as CH4	lb/event	38.8	28	25.7	26.3
PM10/2.5 Total	lb/event	8.1	6.3	6.5	6.2
H2SO4	lb/event	1.0	0.8	0.8	0.7
Heat Consumption	MMBTU HHV	856	717	657	628

Worst-Case estimated 1-hr average exhaust flow = 1840 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

3.2. Fast Hot Start-Up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Condenser Evacuation Prior to Start Initiation					
Duration	min from ign	42	40	39	38
Nox as NO2	lb/event	50	48	47	47
CO	lb/event	25	20	20	20
VOC as CH4	lb/event	17	12	11	11
PM10/2.5 Total	lb/event	6.9	5.0	6.1	4.8
H2SO4	lb/event	0.8	0.7	0.7	0.7
Heat Consumption	MMBTU HHV	815	730	694	676

Worst-Case estimated 1-hr average exhaust flow = 2150 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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3.3. Non-Spinning Reserve Start-up to Compliance (After Approx. 8 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Condenser Evacuation Prior to Start Initiation					
Duration	min from ign	42	40	39	38
Nox as NO2	lb/event	50	49	48	47
CO	lb/event	15	13	13	13
VOC as CH4	lb/event	7.9	6.2	5.7	5.8
PM10/2.5 Total	lb/event	7.2	5.0	6.4	4.6
H2SO4	lb/event	0.8	0.8	0.7	0.7
Heat Consumption	MMBTU HHV	851	776	731	700

Worst-Case estimated 1-hr average exhaust flow = 2400 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

3.4. Normal Warm Start-Up to Compliance (After Approx. 60 hours standstill).

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	129	124	125	125
Nox as NO2	lb/event	56	52	50	50
CO	lb/event	71	52	50	50
VOC as CH4	lb/event	69	46	40	41
PM10/2.5 Total	lb/event	10.4	9.0	9.0	9.0
H2SO4	lb/event	1.3	1.1	1.1	1.1
Heat Consumption	MMBTU HHV	1102	977	963	945

Worst-Case estimated 1-hr average exhaust flow = 1280 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 140F

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3.5. Normal Cold Start-Up to Compliance (After Approx. 200 hours standstill)

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min from ign	183	178	179	178
Nox as NO2	lb/event	61	57	55	54
CO	lb/event	77	56	53	53
VOC as CH4	lb/event	73	48	42	44
PM10/2.5 Total	lb/event	14	12	12	12
H2SO4	lb/event	1.7	1.6	1.6	1.6
Heat Consumption	MMBTU HHV	1502	1354	1324	1299

Worst-Case estimated 1-hr average exhaust flow = 1280 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 120F

3.6. Shutdown: Minimum Emissions Load to Flameout

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	13	11	9.7	9.2
Nox as NO2	lb/event	4.6	3.5	2.9	2.7
CO	lb/event	17	10	8.9	8.9
VOC as CH4	lb/event	25	15	12	13
PM10/2.5 Total	lb/event	1.9	1.4	1.2	1.2
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	179	132	112	103

Worst-Case estimated 1-hr average exhaust flow = 1640 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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3.7. Compliance to Low Load Operation

Note: During Low Load Operation Emissions are in compliance.

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	12	9.9	8.8	8.3
Nox as NO2	lb/event	1.4	1.1	0.9	0.9
CO	lb/event	17	10	8.7	8.7
VOC as CH4	lb/event	24	15	11	13
PM10/2.5 Total	lb/event	1.8	1.3	1.2	1.1
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	168	125	106	98.3

Worst-Case estimated 1-hr average exhaust flow = 1660 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

3.8. Low Load Operation to Compliance

Note: During Low Load Operation Emissions are in compliance.

Ambient Temperature		-10°F	59°F	90°F	100°F
Duration	min	12	9.9	8.8	8.3
Nox as NO2	lb/event	1.5	1.1	1.0	0.9
CO	lb/event	15	10	8.4	8.4
VOC as CH4	lb/event	24	15	11	13
PM10/2.5 Total	lb/event	1.9	1.3	1.2	1.1
H2SO4	lb/event	0.2	0.2	0.1	0.1
Heat Consumption	MMBTU HHV	168	125	106	98.3

Worst-Case estimated 1-hr average exhaust flow = 1660 klb/hr on the hot day

Worst-Case estimated 1-hr average stack temperature = 150F

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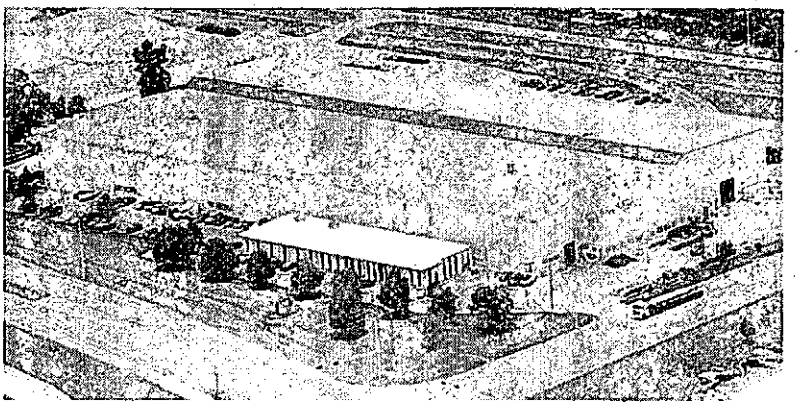
1.0 INTRODUCTION



CB Nebraska Boiler & **CB Natcom** form the engineered boiler/burner division of the **Cleaver-Brooks** family of companies. We are committed to offering integrated boiler/burner solutions to the industry. This group of companies has been in this business for more than 80 years and continues to enjoy a large percentage of the market share. We maintain our leadership in the industrial watertube market by offering innovative solutions and a true single-source responsibility to our customers for boilers, burners, controls & auxiliary equipment. This commitment to overall system design ensures that your equipment operates efficiently and lasts for years to come.

For your unique application, we are offering a packaged solution with the following design features:

1.1 OUTLET STEAM CONDITIONS:

Capacity:	77000 LB/HR ¤
Operating Pressure:	200 PSIG (at exit of non-return valve) ¤
Steam Temperature:	Saturated at 387 °F
Steam Quality:	99.5% dry steam ¤

1.2 BOILER DESIGN:

Type:	D-Type Industrial Watertube
Model:	NB-300D-70
Vessel Design Pressure:	250 psig

1.3 BURNER DESIGN:

Type:	Ultra Low-NOx Register
Main Fuel:	Natural Gas
Emissions:	9 PPM Nox

1.4 ECONOMIZER DESIGN:

Type:	Rectangular Finned-Tube
Arrangement:	Vertical Gas Flow; Counter-Current Water Flow
Design Pressure:	300 psig
Inlet Feedwater Temp:	228°F

1.5 STACK DESIGN:

Type:	Freestanding
Diameter (at exit):	78"
Height (from grade):	125 ft

3.0 BOILER DESIGN DATA

Boiler Dimensions:		**Units**
Height to Main Steam Outlet	14 Ft 7 In	FT
Overall Width of Unit	11 Ft 7.5 In	FT
Overall Length of Unit*	25.33 Ft.	FT
**Add approximately 6-8 ft length for burner.*		
Weight of Unit (Dry)	80,249.49	LBS
Weight of Unit (Wet)	102,381.53	LBS
Surface Area / Volume:		**Units**
Furnace Volume	1,379	FT3
Furnace Projected Area	819	FT2
Evaporator Area	4,277	FT2
Total Area	5,096	FT2
Economizer Area	13,317	FT2
Superheater Area	-	FT2
Tubing Data:		**Units**
Tube OD	2.0	IN
Tube Wall Thickness – Furnace Section	0.105	IN
Tube Wall Thickness – Convection Section	0.105	IN
Tube Material	SA178A	
Corrosion Allowance	NA	IN
Steam Drum:		**Units**
Inside Drum Diameter:	42 In	IN
Drum Length	25.33 Ft. Seam/Seam	FT
Drum Material:	SA516 Grade 70	
Corrosion Allowance:	NA	IN
Water Drum:		**Units**
Drum Diameter:	24 In	IN
Drum Length	25.33 Ft. Seam/Seam	FT
Drum Material:	SA106 Grade B	
Corrosion Allowance:	NA	IN
Standard Drum Connections:	**Quantity**	**Type**
Main Steam Outlet:	One	Flanged
Safety Valves:	Per ASME Code	Flanged
Feedwater Inlet:	One	Flanged
Bottom Drum Blowoff:	Two	Flanged
Water Column:	Two	Threaded (NPT)
Feedwater Regulator:	Two	Flanged
Vent:	One	NPT
Continuous Blowdown:	One	NPT
Chemical Feed:	One	NPT
Sootblower:	Two	Flanged
Auxiliary L.W. Cutouts:	One	NPT

**The above information is preliminary and shall be confirmed at time of engineering submittal.*

4.0 BOILER PERFORMANCE DATA

Fuel: Natural Gas

Boiler load - %	100%	75%	50%	25%	Units
Steam Flow - ¤	77,000	57,750	38,500	19,250	Lb/Hr
Steam Pressure – Operating - ¤	200.0	200.0	200.0	200.0	PSIG
Steam Temperature - ¤	387.0	387.0	387.0	387.0	°F
Fuel Input (HHV)	92.4	69.1	46.0	23.2	MMBTU/Hr
Ambient Air Temperature	80.0	80.0	80.0	80.0	°F
Relative Humidity	60	60	60	60	%
Excess Air	25	25	25	25	%
Flue Gas Recirculation	25	25	25	25	%
Steam Output Duty	77	58	39	19	MMBTU/hr
Heat Release Rate	67,012	50,097	33,366	16,805	BTU/FT3-Hr
Heat Release Rate	112,882	84,389	56,204	28,308	BTU/FT2-Hr
Deaerator Pegging Steam	-	-	-	-	Lb/Hr
Feed Water Temperature	227	227	227	227	°F
Water Temp. Leaving Economizer	321	309	297	288	±10°F
Blow Down	1.0	1.0	1.0	1.0	%
Boiler Gas Exit Temperature	543	498	451	409	±10°F
Economizer Gas Exit Temp.	299	282	266	251	±10°F
Air Flow	84,454	63,137	42,050	21,179	Lb/Hr
Flue Gas to Stack	88,692	66,305	44,160	22,241	Lb/Hr
Flue Gas Including FGR	110,865	82,881	55,200	27,802	Lb/Hr
Fuel Flow	4,237	3,167	2,109	1,062	Lb/Hr
Flue Gas Losses/Efficiency-%					
Dry Gas Loss	4.5	4.2	3.8	3.5	%
Air Moisture Loss	0.1	0.1	0.1	0.1	%
Fuel Moisture Loss	10.6	10.6	10.5	10.4	%
Casing Loss	0.5	0.7	1.0	2.0	%
Margin	0.5	0.5	0.5	0.5	%
Efficiency - LHV	92.8	93.1	93.2	92.5	%
Efficiency – HHV - ¤	83.7	84.0	84.1	83.5	%
Total Pressure Drop Including Economizer	9.46	5.30	2.35	0.56	IN WC
Products of Combustion - CO2	7.7	7.7	7.7	7.7	%
- H2O	16.9	16.9	16.9	16.9	%
-N2	71.7	71.7	71.7	71.7	%
-O2	3.8	3.8	3.8	3.8	%
-SO2	-	-	-	-	%
GAS- % volume	**NG**				
methane	90.00				
ethane	5.00				
nitrogen	5.00				
LHV-Btu/lb	19,687				
HHV-Btu/lb	21,815				

**The above information is preliminary and shall be confirmed at time of engineering submittal.*

DIESEL GENERATOR SET

CATERPILLAR®

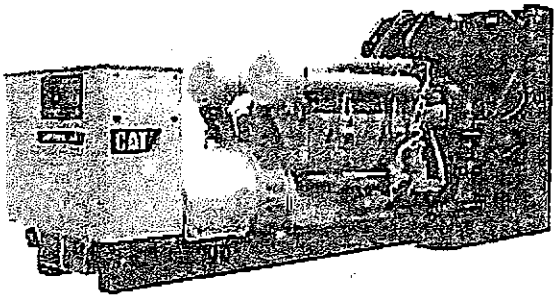


Image shown may not reflect actual package.

STANDBY
1500 ekW 1875 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 listed packages available. Certain restrictions may apply. Consult with your Cat® Dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Cat dealers provide extensive post sale support including maintenance and repair agreements
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT 3512C DIESEL ENGINE
- Reliable, rugged, durable design
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight

CAT GENERATOR
- Designed to match the performance and output characteristics of Cat diesel engines
- Single point access to accessory connections
- UL 1446 recognized Class H insulation

CAT EMCP 3 SERIES CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

SEISMIC CERTIFICATION
- Seismic Certification available
- Anchoring details are site specific, and are dependent on many factors such as generator set size, weight, and concrete strength. IBC Certification requires that the anchoring system used is reviewed and approved by a Professional Engineer
- Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007
- Pre-approved by OSHP and carries an OPA#(OSP-0084-01) for use in healthcare projects in California

CATERPILLAR

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Single element canister type air cleaner with service indicator	[ ] Dual element & heavy duty air cleaners (with pre-cleaners) [ ] Air inlet adapters & shutoff
Cooling	• Radiator fan and fan drive • Fan and belt guards • Coolant level sensors* • Cat Extended Life Coolant*	[ ] Coolant level switch gauge [ ] Heat exchanger and expansion tank
Exhaust	• Exhaust manifold - dry - dual - 8 in • 203 mm (8 in) ID round flanged outlet	[ ] Mufflers [ ] Stainless steel exhaust flex fittings [ ] Elbows, flanges, expanders & Y adapters
Fuel	• Secondary fuel filters • Fuel cooler* • Fuel priming pump • Flexible fuel lines-shipped loose	[ ] Duplex secondary fuel filter [ ] Primary fuel filter with fuel water separator
Generator	• Class H insulation • Cat digital voltage regulator (CDVR) with kVAR/PF control, 3-phase sensing • Winding temperature detectors • Anti-condensation heaters • Reactive Droop	[ ] Oversize & premium generators [ ] Bearing temperature detectors
Power Termination	• Bus bar (NEMA or IEC mechanical lug holes)- right side standard • Top and bottom cable entry	[ ] Circuit breakers, UL listed, 3 pole with shunt trip,100% rated, manual or electrically operated [ ] Circuit breakers, IEC compliant, 3 or 4 pole with shunt trip, manual or electrically operated [ ] Bottom cable entry [ ] Power terminations can be located on the right, left and/or rear as an option
Governor	• ADEM™ 3	[ ] Load share module
Control Panel	• EMCP 3.1 • User interface panel (UIP) - rear mount • AC & DC customer wiring area (right side) • Emergency stop pushbutton	[ ] EMCP 3.2 ... [ ] EMCP 3.3 [ ] Option for right or left mount UIP [ ] Local & remote annunciator modules [ ] Digital I/O Module [ ] Generator temperature monitoring & protection [ ] Remote monitoring software
Lube	• Lubricating oil and filter • Oil drain line with valves • Fumes disposal • Gear type lube oil pump	[ ] Oil level regulator [ ] Deep sump oil pan [ ] Electric & air prelube pumps [ ] Manual prelube with sump pump [ ] Duplex oil filter
Mounting	• Rails - engine / generator / radiator mounting • Anti-vibration mounts (shipped loose)	[ ] Spring-type vibration isolator [ ] IBC isolators
Starting/Charging	• 24 volt starting motor(s) • Batteries with rack and cables • Battery disconnect switch	[ ] Battery chargers (10 & 20 Amp) [ ] 45 amp charging alternator [ ] Oversize batteries [ ] Ether starting aids [ ] Heavy duty starting motors [ ] Barring device (manual) [ ] Air starting motor with control & silencer
Note	Standard and optional equipment may vary for UL 2200 Listed Packages. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.	
General	• Right hand service • Paint - Caterpillar Yellow (with high gloss black rails & radiator) • SAE standard rotation • Flywheel and flywheel housing - SAE No. 00	[ ] CSA certification [ ] CE Certificate of Conformance [ ] Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007 * Not included with packages without radiators

.NDBY 1500 ekW 1875 kVA

.Hz 1800 rpm 480 Volts

CATERPILLAR

SPECIFICATIONS

CAT GENERATOR

SR4B Generator

Frame Size.....697

Excitation.....Permanent Magnet

Pitch.....0.7333

Number of poles.....4

Number of bearings.....1

Number of Leads.....006

Insulation..... UL 1446 Recognized Class H with tropicalization and antiabrasion

IP Rating.....Drip Proof IP22

Alignment..... Pilot Shaft

Overspeed capability- % of rated..... 150

Wave form.....003.00

Paralleling kit/Droop transformer..... Standard

Voltage Regulator3 Phase sensing with selectible volts/Hz

Telephone influence factor.....Less than 50

CAT DIESEL ENGINE

3512C ATAAC, V-12, 4 stroke, water-cooled diesel

Bore..... 170.00 mm (6.69 in)

Stroke..... 190.00 mm (7.48 in)

Displacement.....51.80 L (3161.03 in³)

Compression Ratio..... 14.7:1

Aspiration.....TA

Fuel System..... Electronic unit injection

Governor Type.....ADEM3

CAT EMCP SERIES CONTROLS

- EMCP 3.1 (Standard)
- EMCP 3.2 / EMCP 3.3 (Option)
- Single location customer connector point
- True RMS AC metering, 3-phase
- Controls
  - Run / Auto / Stop control
  - Speed Adjust
  - Voltage Adjust
  - Emergency Stop Pushbutton
  - Engine cycle crank
- Digital Indication for:
  - RPM
  - Operating hours
  - Oil pressure
  - Coolant temperature
  - System DC volts
  - L-L volts, L-N volts, phase amps, Hz
  - ekW, kVA, kVAR, kW-hr, %kW, PF (EMCP 3.2 / 3.3)
- Shutdowns with common indicating light for:
  - Low oil pressure
  - High coolant temperature
  - Low coolant level
  - Overspeed
  - Emergency stop
  - Failure to start (overcrank)
- Programmable protective relaying functions: (EMCP 3.2 & 3.3)
  - Under and over voltage
  - Under and over frequency
  - Overcurrent (time and inverse time)
  - Reverse power (EMCP 3.3)
- MODBUS isolated data link, RS-485 half-duplex (EMCP 3.2 & 3.3)
- Options
  - Vandal door
  - Local annunciator module
  - Remote annunciator module
  - Input / Output module
  - RTD / Thermocouple modules
  - Monitoring software

STANDBY 1500 ekW 1875 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8260	
EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	1875 kVA	
Genset Power rating with fan	1500 ekW	
Coolant to aftercooler		
Coolant to aftercooler temp max	50 ° C	122 ° F
Fuel Consumption		
100% load with fan	396.9 L/hr	104.8 Gal/hr
75% load with fan	310.9 L/hr	82.1 Gal/hr
50% load with fan	219.8 L/hr	58.1 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	2075 m³/min	73278 cfm
Engine Coolant capacity with radiator/exp. tank	390.8 L	103.2 gal
Engine coolant capacity	156.8 L	41.4 gal
Radiator coolant capacity	234.0 L	61.8 gal
Inlet Air		
Combustion air inlet flow rate	129.5 m³/min	4573.3 cfm
Exhaust System		
Exhaust stack gas temperature	406.4 ° C	763.5 ° F
Exhaust gas flow rate	313.2 m³/min	11060.6 cfm
Exhaust flange size (internal diameter)	203.2 mm	8.0 in
Exhaust system backpressure (maximum allowable)	6.7 kPa	26.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	616 kW	35032 Btu/min
Heat rejection to exhaust (total)	1327 kW	75468 Btu/min
Heat rejection to aftercooler	482 kW	27411 Btu/min
Heat rejection to atmosphere from engine	124 kW	7052 Btu/min
Heat rejection to atmosphere from generator	64.1 kW	3645.4 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	2670 skVA	
Frame	697	
Temperature Rise	130 ° C	234 ° F
Lube System		
Sump refill with filter	310.4 L	82.0 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	4.97 g/hp-hr	
CO g/hp-hr	.45 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.03 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034-1, ISO3046, ISO8528, NEMA MG 1-22, NEMA MG 1-33, UL508A, 72/23/EEC, 98/37/EC, 2004/108/EC

Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1349 standard conditions. These ratings also apply at ISO3046 standard conditions. **Fuel rates** are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.00 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Cat representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Cat dealer.

STANDBY 1500 ekW 1875 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR

DIMENSIONS

Package Dimensions		
Length	5895.0 mm	232.09 in
Width	2537.5 mm	99.9 in
Height	2749.5 mm	108.25 in
Weight	14 035 kg	30,942 lb

NOTE: For reference only - do not use for installation design. Please contact your local dealer for exact weight and dimensions. (General Dimension Drawing #2846048).

Performance No.: DM8260

Feature Code: 512DE6C

Gen. Arr. Number: 2628100

Source: U.S. Sourced

October 27 2010

16297533

www.CAT-ElectricPower.com

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Materials and specifications are subject to change without notice. The International System of Units (SI) is used in this publication.

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CLARKE

Fire Protection Products, Inc.

Engine Selection / De-rate Calculator / Speed Interpolator

USA Purchased, USA Installed, 2011 Models, UL/FM Approved, Heat Exchanger Cooled

DATE: 2/18/2011

PUMP REQUIREMENTS:
Pump Max Power: 315 BHP
RPM(s): 1800

DERATE PARAMETERS:
Altitude: 185 (feet)
Ambient Temperature: 77 (°F)
Right Angle Gear Loss: 0%
Derate Percent: .0

APPLICATION INFO:
Customer:
Job Name:
Job Number:
Run By:

RESULTS:

Model	RPM	Rated HP (KW)	Derate HP (KW)	Emissions Tier	Interpolation Data (RPM, HP)
JU6H-UFAD98	1800	315 (235)		T3-Certified	Not used

NOTE:
Derated HP takes into account all the input derates for altitude, temperature and Right Angle Gearbox. When no derates are input, this column will be blank and engine selection(s) will be based upon Rated HP. When the Derated HP column is filled in, then the engine selection(s) are based upon this value

DEFINITIONS:

- UL/FM - Engine that is Underwriters Laboratories Listed and Factory Mutual Approved
- LPCB - Engine that is Loss Prevention Council Board Approved
- NL - Non-Listed Engine has no private agency certification, like UL, or insurance company certification, like FM. It applies to any engine that is not UL Listed or FM Approved, and is built to meet individual European country specifications

North American Offices, 3133 East Kemper Road * Cincinnati, Ohio * 45241 * USA * Tel: +1 (513) 475-3473 * Fax: +1 (513) 771-0726
European Office Grange Works * Lomond Road * Coatbridge, Scotland * ML5 2NN * Tel: +44 (0)1236 429 946 * Fax: +44 (0)1236 427 274

CLARKE

Fire Protection Products, Inc.

Exhaust Backpressure Calculator - Results
Calculations made 2/18/2011

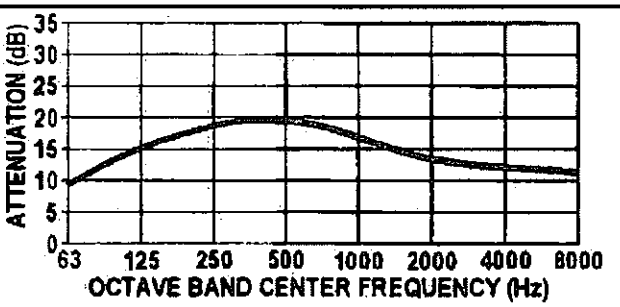
Data input by:

Input Data:

Customer:	Job Name:	Job Number:
Engine Data:	**Piping Data:**	**Silencer Data:**
Manufacturer: Clarke	Pipe Size: 5"	Manufacturer: Clarke USA
Model: JU6H-UFAD98	#90° elbow or Y:	Pipe Size (in): 5
RPM: 1760	Number 45° elbows:	Model: C06545
HP:315	Number Tees:	Application: Industrial
	Straight Pipe (Feet): 30	Connection: 150# Flange

Output Data:

Exh Flow (CFM): 1400
Temperature (° F): 961
Max Backpressure (inches water): 30
Min Backpressure (inches water): 0
Std. Exhaust Dia (in): 5



Exhaust Pipe Recommendation:

BACKPRESSURE CALCULATIONS (inches water)		
	6.5	Pipe
	+ 8.0	Silencer (see note 1)
	14.5	Total
	30.0	Maximum Allowable Backpressure
	Result: Total Backpressure is lower than minimum	

1) CAUTION: Silencer Backpressure is based upon a Clarke USA provided Silencer. Actual Silencer Backpressure will vary depending upon the actual Silencer used (manufacturer, size, type and model). If the total Backpressure from the pipe, Silencer and orifice plate (if required) is close to the engine Maximum Allowed Backpressure, it is highly recommended you obtain the actual Backpressure (for the engine exhaust flow given above) on the Silencer being used and then confirm that the total Backpressure is still under the Maximum Allowed Backpressure.
2) Schedule 40 pipe used in calculations
3) All pipe sizes and lengths are in inches and feet.
4) WARNING: The total Backpressure is less than the engine permissible Backpressure. In order to get the maximum Backpressure above the engine permissible limit, you must change one or more of the following: pipe size; pipe length; Silencer size, Silencer type.

North American Offices:
3133 East Kemper Road * Cincinnati, Ohio * 45241 * USA * Tel: +1 (513) 771-2200 * Fax: +1 (513) 771-0726

European Office:
Grange Works * Lomond Road * Coatbridge, Scotland * ML5 2NN * Tel. +44 (0)1236 429 946 * Fax: +44 (0)1236 427 274

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO. 9, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05 FAST START, COMBINED CYCLE, 2,168 MMBTU/HR AT 41 DEGREES F, WITH DRY LOW NOX COMBUSTORS WITH A/N:	D90	D95 C96	NOX: MAJOR SOURCE**	**CH2O**: 0.091 PPMV NATURAL GAS (8) [**40CFR 63 Subpart YYYY, 4-20-2006**]; **CO**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]; **NOX**: 9.42 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 15 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 30.88 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5A) [**RULE 409, 8-7-1981**]; **PM**: 11 LBS/HR NATURAL GAS (5C) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 9.5 LBS/HR NATURAL GAS (5) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset, 12-6-2002*]; **SO2**: (9) [**40CFR**	A63.3, A99.12, A99.13, A195.12, A195.13, A195.14, A327.1, B61.2, C1.7, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.5, E193.6, I297.3, K40.5, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GENERATOR, HRSG GENERATOR, SERVING UNIT NO. 9, 222 GROSS MW AT 41 DEGREES F STEAM TURBINE, GENERAL ELECTRIC MODEL SC GENERATOR, SERVING STEAM TURBINE, 112 GROSS MW AT 41 DEGREES F				**72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **VOC**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
BURNER, DUCT, NATURAL GAS, 268 MMBTU/HR AT 41 DEGREES F, LOCATED IN THE HRSG OF TURBINE NO. 9 A/N:	D95	D90	NOX: MAJOR SOURCE**	**CH2O**: 0.091 PPMV NATURAL GAS (8) [**40CFR 63 Subpart YYYY, 4-20-2006**]; **CO**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]; **NOX**: 9.42 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 15 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 30.88 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5C) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5B) [**RULE 409, 8-7-1981**]; **PM**: 11 LBS/HR NATURAL GAS (5A) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 9.5 LBS/HR NATURAL GAS (5) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset, 12-6-2002*]; **SO2**: (9) [**40CFR**	A99.12, A99.13, A195.12, A195.13, A195.14, A327.1, B61.2, C1.7, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.5, E193.6, K40.5, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
				72 - Acid Rain Provisions, 11-24-1997]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8A) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **VOC**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996**]	
CO OXIDATION CATALYST, UNIT NO. 9, BASF, 290 FEET OF TOTAL CATALYST VOLUME A/N:	C96	D90 C97			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 9, CORMETECH, 2050 CU.FT.; WIDTH: 9 FT 10 IN; HEIGHT: 6 FT 4 IN; LENGTH: 1 FT 9 IN WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C97	C96 S99		**NH3**: 5 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	D12.14, D12.15, D12.16, E179.7, E179.8, E193.2, E193.7
STACK, SERVING UNIT NO. 9, HEIGHT: 210 FT ; DIAMETER: 20 FT A/N:	S99	C97			

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO. 11, NATURAL GAS, ROLLS ROYCE, MODEL TRENT 60, SIMPLE CYCLE, 516 MMBTU/HR AT 78 DEGREES F, WITH WATER INJECTION WITH A/N:	D100	C102	NOX: MAJOR SOURCE**	**CH2O**: 0.091 PPMV NATURAL GAS (8) [**40CFR 63 Subpart YYYY, 4-20-2006**]; **CO**: 4 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2.5 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]; **NOX**: 15 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 16.16 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 96.58 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5A) [**RULE 409, 8-7-1981**]; **PM**: 11 LBS/HR NATURAL GAS (5C) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 5 LBS/HR NATURAL GAS (5) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset,*	A63.4, A99.14, A99.15, A195.15, A195.16, A195.17, A327.1, B61.2, C1.8, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.5, E193.8, I297.4, K40.5, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GENERATOR, 57.4 GROSS MW AT 78 DEGREES F				*12-6-2002*]; **SO2**: (9) [**40CFR 72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **VOC**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, UNIT NO. 11, PEERLESS, CATALYST VOLUME: 420 CUBIC FEET A/N:	C102	D100 C103			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 11, PEERLESS, 1272 CU.FT.; WIDTH: 19 FT 6 IN; HEIGHT: 33 FT ; LENGTH: 2 FT 6 IN WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C103	C102 S105		**NH3**: 5 PPMV NATURAL GAS (4) [**RULE 1303(b)(2) -Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset, 12-6-2002*]	D12.17, D12.18, D12.19, E179.9, E179.10, E193.2, E193.7
STACK, SERVING UNIT NO. 11, DIAMETER: 11.1 FT, HEIGHT: 150 FT, HEIGHT: 150 FT ; DIAMETER: 11 FT A/N:	S105	C103			

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

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FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO. 12, NATURAL GAS, ROLLS ROYCE, MODEL TRENT 60, SIMPLE CYCLE, 516 MMBTU/HR AT 78 DEGREES F, WITH WATER INJECTION WITH A/N:	D106	C108	NOX: MAJOR SOURCE**	**CH2O**: 0.091 PPMV NATURAL GAS (8) [**40CFR 63 Subpart YYYY, 4-20-2006**]; **CO**: 4 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2.5 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]; **NOX**: 16.16 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 25 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 96.58 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5C) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5A) [**RULE 409, 8-7-1981**]; **PM**: 11 LBS/HR NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 5 LBS/HR NATURAL GAS (5) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset, 12-6-2002*]; **SO2**: (9) [**40CFR**	A63.4, A99.14, A99.15, A195.15, A195.16, A195.17, A327.1, B61.2, C1.8, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.3, E193.5, E193.8, I297.5, K40.5, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GENERATOR, 57.4 GROSS MW AT 78 DEGREES F				**72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **VOC**: 2 PPMV NATURAL GAS (4) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2) -Offset, 12-6-2002*]	
CO OXIDATION CATALYST, UNIT NO. 12, PEERLESS, WITH 420 CUBIC FEET OF TOTAL CATALYST VOLUME A/N:	C108	D106 C109			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 12, PEERLESS, 1272 CU.FT.; WIDTH: 19 FT 6 IN; HEIGHT: 33 FT ; LENGTH: 2 FT 6 IN WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C109	C108 S111		**NH3**: 5 PPMV NATURAL GAS (4) [**RULE 1303(b)(2) -Offset, 5-10-1996;** *RULE 1303(b)(2)-Offset, 12-6-2002*]	D12.17, D12.18, D12.19, E179.9, E179.10, E193.2, E193.7
STACK, SERVING UNIT NO. 12, HEIGHT: 150 FT ; DIAMETER: 11 FT A/N:	S111	C109			
System 2: GAS TURBINE POWER GENERATION					

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO.5, NATURAL GAS, SIEMENS, MODEL SGT6-5000F RAPID-RESPONSE, COMBINED CYCLE, 2,096 MMBTU/HR AT 78 DEGREES F, WITH DRY LOW-NOX COMBUSTORS WITH A/N: 470652 Permit to Construct Issued: 07/13/10	D67	C75	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **NOX**: 8.66 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 15 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 16.55 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5A) [**RULE 409, 8-7-1981;** RULE 410, 10-6-2006]; **PM**: 11 LBS/HR NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) [**40CFR 72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart**	A63.2, A99.7, A99.8, A99.9, A99.10, A99.11, A195.8, A195.9, A195.10, A327.1, A433.1, B61.2, C1.6, D12.10, D29.7, D29.8, D29.9, D82.4, D82.5, E193.2, E193.3, I297.1, K40.4, K67.5

* (1) (1A) (1B) Denotes RECLAIM emission factor (2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit (4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit (8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits (10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GENERATOR, HEAT RECOVERY STEAM, UNFIRED TURBINE, STEAM, 67.7 MW GENERATOR, 219 MW				**KKKK, 7-6-2006**]; **VOC**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, UNIT NO. 5, BASF, 290 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 470653 Permit to Construct Issued: 07/13/10	C75	D67 C76			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 5, CORMETECH, MODEL CM21HT, WITH 2,050 CUBIC FEET OF TOTAL CATALYST VOLUME, WIDTH: 25 FT ; HEIGHT: 70 FT ; LENGTH: 24 FT 3 IN WITH A/N: AMMONIA INJECTION, GRID	C76	C75 S78		**NH3**: 5 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	A195.11, D12.11, D12.12, D12.13, E179.5, E179.6
STACK, NO. 5, HEIGHT: 210 FT ; DIAMETER: 20 FT 11 IN A/N: 470652 Permit to Construct Issued: 07/13/10	S78	C76			

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO.7, NATURAL GAS, SIEMENS, MODEL SGT6-5000F RAPID-RESPONSE, COMBINED CYCLE, 2,096 MMBTU/HR AT 78 DEGREES F, WITH DRY LOW-NOX COMBUSTORS WITH A/N: 470656 Permit to Construct Issued: 07/13/10	D68	C79	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **NOX**: 8.66 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 15 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **NOX**: 16.55 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **PM**: 0.01 GRAINS/SCF NATURAL GAS (5) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5A) [**RULE 409, 8-7-1981**]; **PM**: 11 LBS/HR NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) [**40CFR 72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **VOC**: 2	A63.2, A99.7, A99.8, A99.9, A99.10, A99.11, A195.8, A195.9, A195.10, A327.1, A433.1, B61.2, C1.6, D12.10, D29.7, D29.8, D29.9, D82.4, D82.5, E193.2, E193.3, I297.2, K40.4, K67.5

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
GENERATOR, HEAT RECOVERY STEAM, UNFIRED TURBINE, STEAM, 67.7 MW GENERATOR, 219 MW				PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, UNIT NO. 7, BASF, 290 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 470654 Permit to Construct Issued: 07/13/10	C79	D68 C80			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 7, CORMETECH, MODEL CM21HT, WITH 2,050 CUBIC FEET OF TOTAL CATALYST VOLUME, WIDTH: 25 FT ; HEIGHT: 70 FT ; LENGTH: 24 FT 3 IN WITH A/N: AMMONIA INJECTION, GRID	C80	C79 S82		**NH3**: 5 PPMV NATURAL GAS (4) [**RULE 1303(a)(1) -BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	A195.11, D12.11, D12.12, D12.13, E179.5, E179.6
STACK, NO. 7, HEIGHT: 210 FT ; DIAMETER: 20 FT 11 IN A/N: 470656 Permit to Construct Issued: 07/13/10	S82	C80			
Process 2: EXTERNAL COMBUSTION					

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 2: EXTERNAL COMBUSTION					
BOILER, AUXILIARY, NATURAL GAS, CLEAVER BROOKS, MODEL NB-100D-40, WATER TUBE, WITH LOW NOX BURNER, 36 MMBTU/HR WITH A/N:	D112		NOX: LARGE SOURCE**	**CO**: 50 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 5 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005**]; **PM**: 0.1 GRAINS/SCF NATURAL GAS (5) [**RULE 409, 8-7-1981**]	B61.2, C1.9, D29.13, E193.2, I297.6, K40.5
BURNER, NATURAL GAS, WITH LOW NOX BURNER, 36 MMBTU/HR	C113				

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: DEVICE ID INDEX

The following sub-section provides an index to the devices that make up the facility description sorted by device ID.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: DEVICE ID INDEX

Device Index For Section H			
Device ID	**Section H Page No.**	**Process**	**System**
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C75	11	1	2
C76	11	1	2
S78	11	1	2
C79	13	1	2
C80	13	1	2
S82	13	1	2
D90	3	1	0
D95	5	1	0
C96	5	1	0
C97	5	1	0
S99	5	1	0
D100	7	1	0
C102	7	1	0
C103	7	1	0
S105	7	1	0
D106	9	1	0
C108	9	1	0
C109	9	1	0
S111	9	1	0
D112	14	2	0
C113	14	2	0

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

FACILITY CONDITIONS

F2.1 The operator shall limit emissions from this facility as follows:

CONTAMINANT	EMISSIONS LIMIT
PM	Less than 100 TONS IN ANY ONE YEAR

For the purpose of this condition, the PM emission limit shall be applicable to particulate matter with aerodynamic diameter less than 2.5 microns

The operator shall not operate any of the new gas turbines #9, 11, and 12 or the auxiliary boiler unless it demonstrates compliance with this limit

The operator shall calculate the emission limits(s) by using the calendar monthly fuel use data and the following emission factors: PM2.5: 4.09 lb/mmscf for GE 7FA combined cycle gas turbine; 9.98 lb/mmscf for Trent 60 simple cycle gas turbines; 8.82 lb/mmscf for auxiliary boiler.

For the purpose of this condition any one year shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12 month period beginning on the first day of each calendar month.

[**40CFR 51 Subpart S, 3-8-2007**]

F9.1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[**RULE 401, 3-2-1984;** RULE 401, 11-9-2001]

F14.1 The operator shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

[**RULE 431.2, 5-4-1990;** RULE 431.2, 9-15-2000]

F14.2 The operator shall not purchase fuel oil containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

This condition shall become effective on or after June 1, 2004.

[RULE 431.2, 9-15-2000]

F16.1 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

purchase records of fuel oil and sulfur content of the fuel

[**RULE 3004(a)(4)-Periodic Monitoring, 8-11-1995; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997**]

F18.1 Acid Rain SO2 Allowance Allocation for affected units are as follows:

Device ID	Boiler ID	Contaminant	Tons in any year
7	Boiler No. 1	SO2	437
9	Boiler No. 2	SO2	90
11	Boiler No. 3	SO2	182
13	Boiler No. 4	SO2	370

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

a). The allowance allocation(s) shall apply to calendar years 2000 through 2009.

b). The number of allowances allocated to Phase II affected units by U.S. EPA may change in a 1998 revision to 40CFR73 Tables 2,3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO2 allowance allocations identified in this permit (see 40 CFR 72.84)

[**40CFR 73 Subpart B, 1-11-1993**]

F24.1 Accidental release prevention requirements of Section 112(r)(7):

a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.

[**40CFR 68 - Accidental Release Prevention, 5-24-1996**]

F52.1 This facility is subject to the applicable requirements of the following rules or regulation(s):

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The facility shall submit a detailed retirement plan for the permanent shutdown of Boiler #4 (Device D13) describing in detail the steps and schedule that will be taken to render Boiler #4 permanently in operable. The retirement plan shall be submitted to SCAQMD within 60 days after the permits to construct for Gas Turbine Units 9, 11, and 12 are issued.

The retirement plan must be approved in writing by SCAQMD. El Segundo Power, LLC shall not commence any construction of the ESPFM Project including Gas Turbine Units 9,11, and 12, Steam Turbine Unit 10, SCR/CO Catalysts for Gas Turbines 9, 11, and 12, and the Auxiliary Boiler before the retirement plan is approved in writing by SCAQMD. If SCAQMD notified El Segundo Power, LLC that the plan is not approvable, El Segundo Power, LLC shall submit a revised plan addressing SCAQMD's concerns within 30 days.

El Segundo Power, LLC shall provide SCAQMD by December 31, 2015 with a notarized statement that Boiler #4 is permanently shut down and that any re-start or operation of the unit shall require new Permit to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

El Segundo Power, LLC shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shut down of Boiler #4, or advise SCAQMD as soon as practicable should El Segundo Power, LLC undertake permanent shutdown prior to December 31, 2015.

El Segundo Power, LLC shall cease operation of Boiler #4 within 90 calendar days for the first fire of Gas Turbine Unit 9 (Device D90), Unit 11 (Device D100) , or Unit 12 (Device D106), whichever occurs first.

[**RULE 1304(a)-Modeling and Offset Exemption, 6-14-1996**]

DEVICE CONDITIONS

A. Emission Limits

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

A63.2 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 6935 LBS IN ANY ONE MONTH
SOX	Less than or equal to 1065 LBS IN ANY ONE MONTH
VOC	Less than or equal to 4930 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emissions for VOC, PM10, and SOx, using the equation below and the following emission factors: VOC 2.93 lb/mmcf; PM10 4.66 lb/mmcf; and SOx 0.72 lb/mmcf

Monthly Emissions, lb/month = X * (EF)

where X = monthly fuel usage, mmcf/month; and EF = emission factor indicated above

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D67, D68]

A63.3 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 39191 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 7546 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 8222 LBS IN ANY CALENDAR MONTH
SOX	Less than or equal to 945 LBS IN ANY CALENDAR MONTH

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The above limits apply after the equipment has been fully commissioned

The operator shall calculate the emission limits by using the calendar monthly fuel use data and the following emission factors: VOC: 2.92 lb/mmscf, PM10: 4.51 lb/mmscf, SOx: 0.60 lb/mmscf

The operator shall calculate the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated by using monthly fuel use data and the following factors: natural gas commissioning: 22.52 lb/mmscf, normal operation: 13.86 lb/mmscf

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(3) PSD Analysis, 10-7-1988**]

[Devices subject to this condition : D90]

A63.4 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 10663 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 1203 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 2200 LBS IN ANY CALENDAR MONTH
SOX	Less than or equal to 130 LBS IN ANY CALENDAR MONTH

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The above limits apply after the equipment has been fully commissioned. The above limits apply to each turbine individually

The operator shall calculate the emission limits by using the calendar monthly fuel use data and the following emission factors: VOC: 2.66 lb/mmscf, PM10: 9.98 lb/mmscf, SOx: 0.60 lb/mmscf

The operator shall calculate the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated by using monthly fuel use data and the following factors: natural gas commissioning: 258.44 lb/mmscf, normal operation: 9.30 lb/mmscf

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(3) PSD Analysis, 10-7-1988**]

[Devices subject to this condition : D100, D106]

A99.7 The 2.0 PPM NOX emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 gas turbine operating hours. Start-up shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 200 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

A gas turbine operating hour during the commissioning period consists of 60 operating minutes. An operating minute occurs when the gas turbine fuel flow during that minute is greater than zero.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : D67, D68]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

A99.8 The 2.0 PPM CO emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 gas turbine operating hours. Start-up shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 200 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

A gas turbine operating hour during the commissioning period consists of 60 operating minutes. An operating minute occurs when the gas turbine fuel flow during that minute is greater than zero.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D67, D68]

A99.9 The 2.0 PPM VOC emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 gas turbine operating hours. Start-up shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 200 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

A gas turbine operating hour during the commissioning period consists of 60 operating minutes. An operating minute occurs when the gas turbine fuel flow during that minute is greater than zero.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D67, D68]

A99.10 The 16.55 LBS/MMCF NOX emission limit(s) shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[**RULE 2012, 5-6-2005**]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : D67, D68]

A99.11 The 8.66 LBS/MMCF NOX emission limit(s) shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D67, D68]

A99.12 The 30.88 LBS/MMSCF NOX emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D90, D95]

A99.13 The 9.42 LBS/MMSCF NOX emission limit(s) shall only apply during the interim period after turbine commissioning to report RECLAIM emissions.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D90, D95]

A99.14 The 96.58 LBS/MMSCF NOX emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D100, D106]

A99.15 The 16.16 LBS/MMSCF NOX emission limit(s) shall only apply during the interim period after turbine commissioning to report RECLAIM emissions.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D100, D106]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

A195.8 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry basis.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D67, D68]

A195.9 The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry basis.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(1)-Modeling, 5-10-1996;** RULE 1303(b)(1)-Modeling, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D67, D68]

A195.10 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry basis.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(1)-Modeling, 5-10-1996;** RULE 1303(b)(1)-Modeling, 12-6-2002]

[Devices subject to this condition : D67, D68]

A195.11 The 5 PPMV NH3 emission limit(s) is averaged over 60 minutes at 15 percent O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b; where

a = NH3 injection rate (lb/hr)/17 lb/lb-mol

b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol

c = change in measured NOx across the SCR, (ppmvd at 15 percent O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The operator shall use the above described method or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved refernce method for the determination of ammonia.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 2012, 5-6-2005**]

[Devices subject to this condition : C76, C80]

A195.12 The 2.0 PPMV NOX emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, fast start-ups, traditional start-ups, and shutdown periods. The turbine commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The gas turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year.

Written records of commissioning, fast start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D90, D95]

A195.13 The 2.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, fast start-ups, traditional start-ups, and shutdown periods. The turbine commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The gas turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year.

Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D90, D95]

A195.14 The 2.0 PPMV VOC emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, fast start-ups, traditional start-ups, and shutdown periods. The turbine commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The gas turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year.

Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D90, D95]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

A195.15 The 2.5 PPMV NOX emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, start-ups, and shutdown periods. The turbine commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The gas turbine shall be limited to a maximum of 480 start-ups per year.

Written records of commissioning, start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D100, D106]

A195.16 The 4.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, start-ups, and shutdown periods. The turbine commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The gas turbine shall be limited to a maximum of 480 start-ups per year.

Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D100, D106]

A195.17 The 2.0 PPMV VOC emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, start-ups, and shutdown periods. The turbine commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The gas turbine shall be limited to a maximum of 480 start-ups per year.

Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

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The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : D100, D106]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[**RULE 475, 10-8-1976;** RULE 475, 8-7-1978]

[Devices subject to this condition : D67, D68, D90, D95, D100, D106]

A433.1 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for NOx, except as defined in condition A99.7 and for the following scenario:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up	112 lb/hr	NOx emissions not to exceed 112 lbs total per start-up per turbine. Each turbine shall be limited to 200 start-ups per year, with each start-up not to exceed 60 minutes

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : D67, D68]

B. Material/Fuel Type Limits

B61.2 The operator shall not use natural gas containing the following specified compounds:

Compound	Range	grain per 100 scf
H2S	greater than	0.25

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The operator shall comply with the terms and conditions set forth below:

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier documentation. The gaseous fuel sample shall be tested using District Method 307-91 for total sulfur calculated as H2S

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D67, D68, D90, D95, D100, D106, D112]

C. Throughput or Operating Parameter Limits

C1.6 The operator shall limit the fuel usage to no more than 1500 MM cubic feet in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single turbine.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D67, D68]

C1.7 The operator shall limit the number of start-ups to no more than 62 in any one calendar month.

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The operator shall comply with the terms and conditions set forth below:

The number of fast start-ups shall not exceed 47 per month. The number of traditonal start-ups shall not exceed 15 per month.

The number of fast start-ups shall not exceed 1 per day. The number of traditional start-ups shall not exceed 1 per day.

NOx emissions during a fast start-up shall not exceed 36 lbs. NOx emissions during a traditional start-up shall not exceed 62 lbs.

The beginning of start-up occurs at initial fire in the combustor and the end of start-up occurs when BACT levels are achieved. If during start-up the process is aborted, the process will count as one start-up.

Th operator shall maintain records in a manner approved by the District to demonstarte compliance with this condition..

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : D90, D95]

C1.8 The operator shall limit the number of start-ups to no more than 60 in any one calendar month.

The number of start-ups shall not exceed 4 per day.

NOx emissions during a start-up shall not exceed 28 lbs..

The NOx emissions from a startup shall not exceed 28 lbs. The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

Th operator shall maintain records in a manner approved by the District to demonstarte compliance with this condition..

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The operator shall comply with the terms and conditions set forth below:

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : D100, D106]

C1.9 The operator shall limit the fuel usage to no more than 0.82 MM cubic feet per day.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 2005, 6-3-2011**]

[Devices subject to this condition : D112]

D. Monitoring/Testing Requirements

D12.10 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage of the turbine.

The operator shall also install and maintain a device to continuously record the parameter being measured.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 2012, 5-6-2005**]

[Devices subject to this condition : D67, D68]

D12.11 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The ammonia injection rate shall remain between 1 gallon per hour and 75 gallons per hour

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The operator shall comply with the terms and conditions set forth below:

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : C76, C80]

D12.12 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature of the in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The temperature shall remain between 400 degrees F and 750 degrees F

The catalyst temperature shall not exceed 750 degrees F during the start-up period.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : C76, C80]

D12.13 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure drop acorss the catalyst shall remain between 1 inch of water column and 4 inches of water column

The pressure drop across the catalyst shall not exceed 4 inches of water during the start-up period.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : C76, C80]

D12.14 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The ammonia injection rate shall not exceed 135 lb/hr

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C97]

D12.15 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The temperature shall remain between 300 degrees F and 650 degrees F

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C97]

D12.16 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure drop across the catalyst shall remain between 1 inch of water column and 4 inches of water column

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005**]

[Devices subject to this condition : C97]

D12.17 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The ammonia injection rate shall not exceed 47 lb/hr

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C103, C109]

D12.18 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The temperature shall remain between 600 degrees F and 1,125 degrees F

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C103, C109]

D12.19 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure drop across the catalyst shall remain between 1 inch of water column and 12 inches of water column

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005**]

[Devices subject to this condition : C103, C109]

D29.7 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 5	4 hours	Outlet of the SCR serving this equipment
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
NH3 emissions	AQMD Laboratory Method 307-91	1 hour	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in megawatts (MW).

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at maximum, average, and minimum loads.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters is done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA method TO-12 (with preconcentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results shall be reported with two significant digits.

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The operator shall comply with the terms and conditions set forth below:

For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of AQMD and EPA

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D67, D68]

D29.8 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the AQMD within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first 12 months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to determine compliance with the Rule 1303 BACT concentration limit.

If the equipment is not operated in any given quarter, the operator may elect to defer the required testing to a quarter in which the equipment is operated.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

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The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : D67, D68]

D29.9 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 5	4 hours	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

The test(s) shall be conducted at least once every three years for SOx and PM10, and yearly for VOC.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in megawatts (MW).

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at 100 percent load.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters is done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA method TO-12 (with preconcentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results shall be reported with two significant digits.

For the purpose of this condition, alternative test methods may be allowed for

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The operator shall comply with the terms and conditions set forth below:

each of the above pollutants upon concurrence of AQMD and EPA

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D67, D68]

D29.10 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District method	District-approved averaging time	Outlet of the SCR serving this equipment
PM2.5	Approved District method	District-approved averaging time	Outlet of the SCR serving this equipment
SOX emissions	Approved District method	District-approved averaging time	Fuel sample
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), and the flue gas flow rate. The combined gas turbine and steam turbine generating output in MW shall also be recorded..

The test shall be conducted in accordance with a District approved source etst protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by District before the test commences..

The test protocol shall include the proposed operating conditions of the gas turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canister temperature when extracting samples for analysis is not below 70 degrees F

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted when this equipment is operating at loads of 100 and 75 percent of maximum load for the NOx, CO, VOC, and ammonia tests. The PM10 and PM2.5 tests shall be conducted when this equipment is operating at 100 percent of maximum load.

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[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 1703(a)(3) PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : D90, D95, D100, D106]

D29.11 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District-approved averaging time	Fuel sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District method	District-approved averaging time	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

The test shall be conducted at least once every three years.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when the gas turbine is operating at 100 percent of maximum load.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canister temperature when extracting samples for analysis is not below 70 degrees F

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emission limit.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D90, D95, D100, D106]

D29.12 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location

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NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D90, D95, D100, D106]

D29.13 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District method 207.1 and 5.3 or EPA method 17	District-approved averaging time	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine compliance with the BACT emission limits. NOx and CO concentrations shall be corrected to 3% excess O2, dry. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, oxygen level in the flue gas. The steam turbine generator output in MW shall also be recorded..

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures..

The test shall be conducted when this equipment is operating at loads of 100 and 75 percent of maximum load

Test results shall be submitted to AQMD with 90 days of the completion of the tests.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 1703(a)(3) PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : D112]

D82.4 The operator shall install and maintain a CEMS to measure the following parameters:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving intial approval from AQMD. Within two weeks of turbine start-up, the operator shall provide written notification to the AQMD of the exact date of start-up.

The CEMS shall be installed and operated to measure the CO concentration over a 15 minute averaging time period.

The CEMS shall convert the actual CO concentrations to mass emission rates (lb/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, (lb/hr) = K Cco Fd[20.9/(20.9-%O2)][(Qg * HHV)/1000000], where

K = 7.267 EE-8 (lb/scf)/ppm

Cco = Average of four consecutive 15 min avg CO concentrations, ppm

Fd = 8710 dscf/MMBTU natural gas

%O2 = Hourly avg % by volume O2, dry basis, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 218, 8-7-1981; RULE 218, 5-14-1999**]

[Devices subject to this condition : D67, D68]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

D82.5 The operator shall install and maintain a CEMS to measure the following parameters:

NOX concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the AQMD of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start-up of the turbine.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005; RULE 2012, 5-6-2005**]

[Devices subject to this condition : D67, D68]

D82.6 The operator shall install and maintain a CEMS to measure the following parameters:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS will convert the actual CO concentrations to mass emission rates (lb/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission rate, lb/hr = K*Cco*Fd[20.9/(20.9-%O2d)][(Qg*HHV)/1E6], where

K = 7.267E-8 (lb/scf)/ppm

Cco = Average of four consecutive 15 minnute average CO concentrations, ppmv

Fd = 8710 dscf/MMBTU natural gas

%O2d = Hourly average % by vol. O2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross higher heating value of fuel, BTU/scf

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D90, D95, D100, D106]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

D82.7 The operator shall install and maintain a CEMS to measure the following parameters:

NOX concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated no later than 90 days after intial start-up of the turbine, and in accordance with an approved SCAQMD REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD. Within two weeks of the initial start-up, the operator shall provide written notification to the District of the exact date of start-up.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3)

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2012, 5-6-2005**]

[Devices subject to this condition : D90, D95, D100, D106]

E. Equipment Operation/Construction Requirements

E179.5 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D 12-11

Condition Number D 12-12

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C76, C80]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

E179.6 For the purpose of the following condition number(s), continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number D 12-13

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : C76, C80]

E179.7 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated upon the average of the continuous monitoring for that hour.

Condition Number D 12-14

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : C97]

E179.8 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated upon the average of the continuous monitoring for that month.

Condition Number D 12-15

Condition Number D 12-16

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : C97]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

E179.9 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated upon the average of the continuous monitoring for that hour.

Condition Number D 12-17

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : C103, C109]

E179.10 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated upon the average of the continuous monitoring for that month.

Condition Number D 12-18

Condition Number D 12-19

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : C103, C109]

E193.2 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 00-AFC-14C project

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition : D67, D68, D90, D95, C97, D100, C103, D106, C109, D112]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The combined cycle gas turbine units 5 and 7 shall not operate simultaneously with boiler units 1,2, or 3 except for the 90 day period as stipulated in AQMD Rule 1313. El Segundo Power shall surrender the Permit to Operate (P/N F14448) for boiler no. 3 within 90 days of the start-up of the combined cycle gas turbines.

[**RULE 1313(d), 12-7-1995**]

[Devices subject to this condition : D67, D68, D106]

E193.5 The operator shall operate and maintain this equipment according to the following requirements:

The operator shall vent this equipemnt to the oxidation catalyst and SCR control system whenever the gas turbine is in operation after initial commissioning.

The operator shall provide the SCAQMD with written notification of the initial start-up date.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]

[Devices subject to this condition : D90, D95, D100, D106]

E193.6 The operator shall operate and maintain this equipment according to the following requirements:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions of each calendar month using the following formula

GHG = 60.139*FF, where

Where, GHG is the greenhouse gas emissions in tons of CO2e and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 878,679 tons per year. The GHG emissions shall not exceed 967 lbs per net megawatt-hours.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

[RULE 1714, 11-5-2010]

[Devices subject to this condition : D90, D95]

E193.7 The operator shall locate and operate this equipment according to the following requirements:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:

NH3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where

a=NH3 injection rate (lb/hr)/17(lb/lb-mol), b= dry exhaust flow rate (scf/hr)/ (385.5 scf/lb-mol), c = change in measured NOx across the SCR, ppmvd at 15 percent O2.

The operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia. The ammonia slip calculation procedure shall be in-effect no later than 90 days after initial startup of the turbine.

[**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2012, 5-6-2005**]

[Devices subject to this condition : C97, C103, C109]

E193.8 The operator shall operate and maintain this equipment according to the following requirements:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions of each calendar month using the following formula

GHG = 60.139*FF, where

Where, GHG is the greenhouse gas emissions in tons of CO2e and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 140,998 tons per year. The GHG emissions shall not exceed 1,503 lbs per net megawatt-hours.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

[RULE 1714, 11-5-2010]

[Devices subject to this condition : D100, D106]

I. Administrative

I297.1 This equipment shall not be operated unless the facility holds 52432 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 5-6-2005**]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : D67]

I297.2 This equipment shall not be operated unless the facility holds 52432 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 5-6-2005**]

[Devices subject to this condition : D68]

I297.3 This equipment shall not be operated unless the facility holds 148226 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition : D90]

I297.4 This equipment shall not be operated unless the facility holds 46675 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 6-3-2011**]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : D100]

I297.5 This equipment shall not be operated unless the facility holds 46675 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition : D106]

I297.6 This equipment shall not be operated unless the facility holds 521 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition : D112]

K. Record Keeping/Reporting

K40.4 The operator shall provide to the District a source test report in accordance with the following specifications:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM Cubic Feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703 - PSD Analysis, 10-7-1988; RULE 2005, 5-6-2005**]

[Devices subject to this condition : D67, D68]

K40.5 The operator shall provide to the District a source test report in accordance with the following specifications:

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Source test results shall be submitted to the District no later than 90 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM Cubic Feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition : D90, D95, D100, D106, D112]

K67.5 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification

Natural gas fuel use during the commissioning period

Natural gas fuel use after the commissioning period and prior to CEMS certification

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D67, D68]

FACILITY PERMIT TO OPERATE
EL SEGUNDO POWER, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

K67.6 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition : D90, D95, D100, D106]