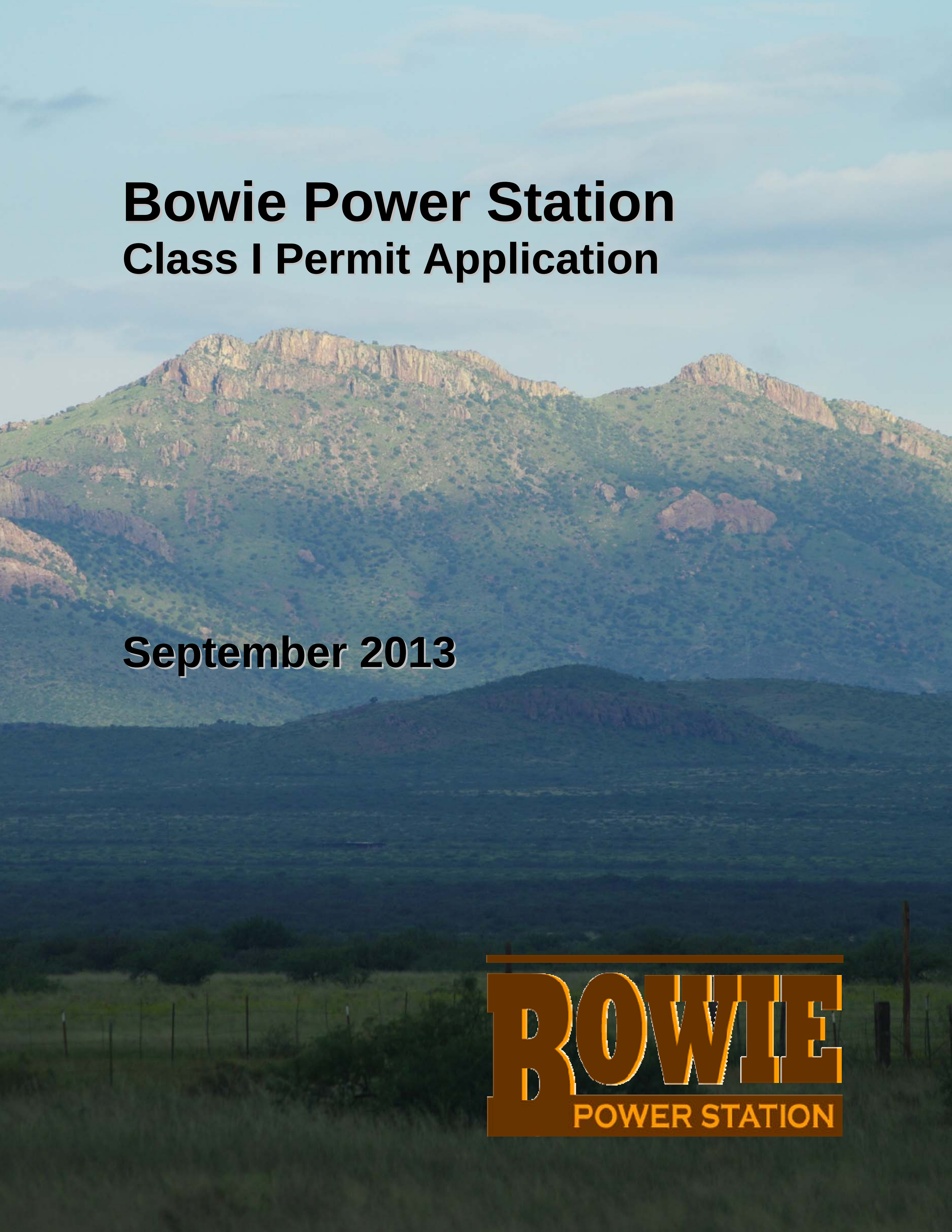
Bowie Power Station
Class I Permit Application

September 2013



BOWIE
POWER STATION

BOWIE POWER STATION

Class I Permit Application

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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 (μg/m^3)	Class II Modeling Significance Level (μg/m^3)	Significant Monitoring Level (μg/m^3)	Limiting NAAQS/AAAQS (μg/m^3)	Class II PSD Increment (μg/m^3)	Bowie Power Station Maximum Predicted Class I Impact (μg/m^3)	Class I Modeling Significance Level (μg/m^3)	Class I PSD Increment (μg/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.

μg/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

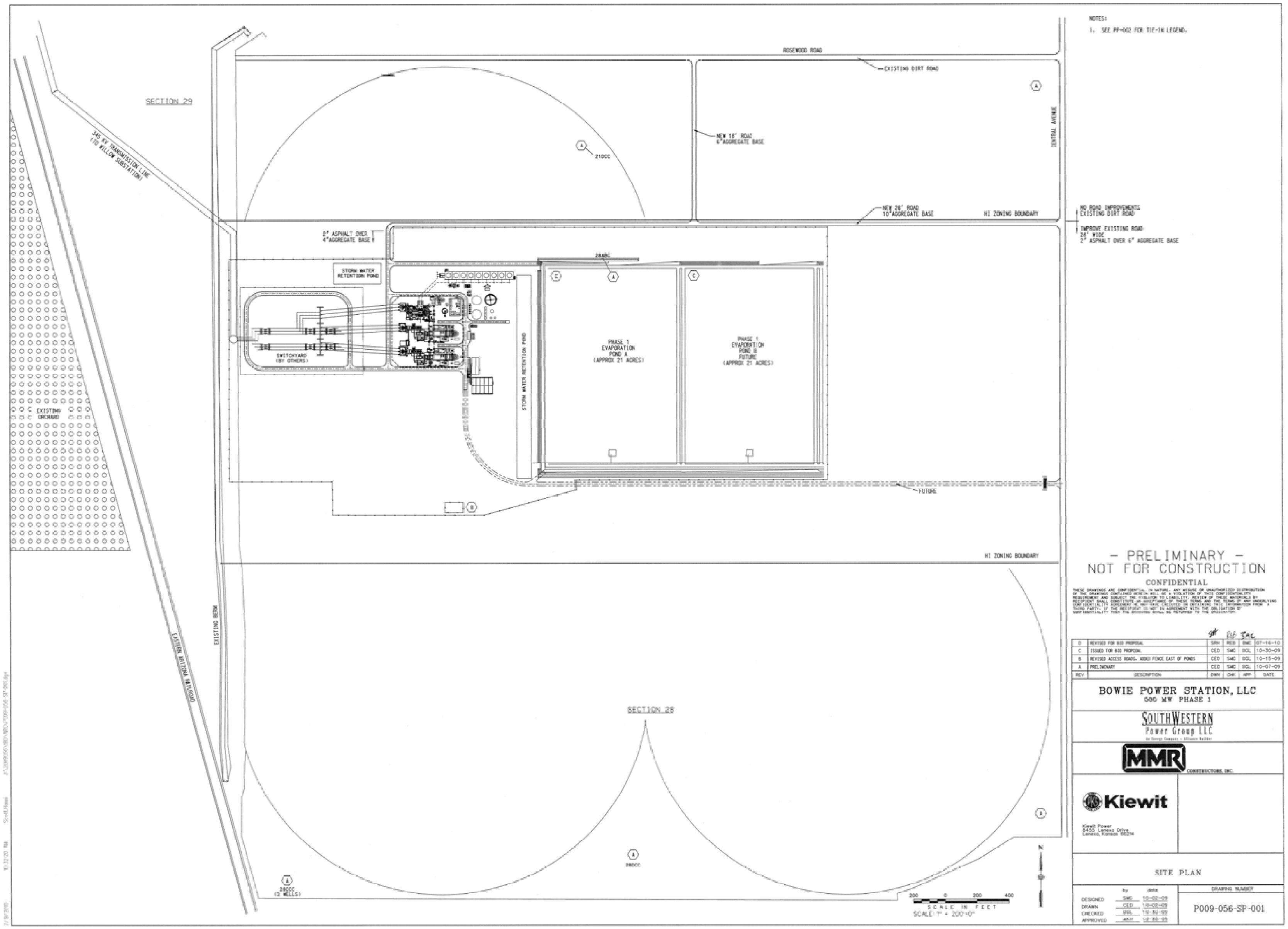

Figure 2-2. Bowie Power Station Site Plan

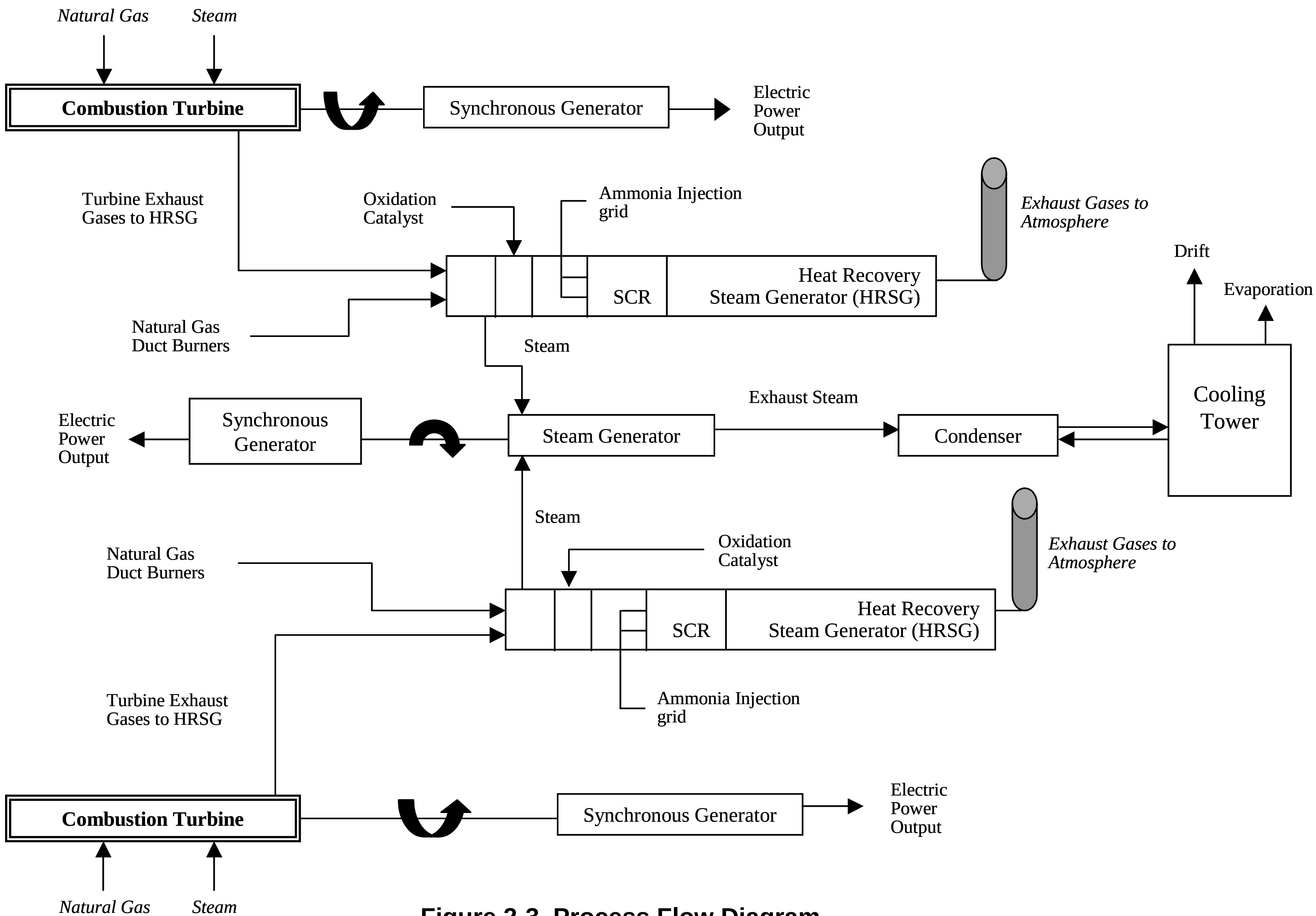

Figure 2-3. Process Flow Diagram

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^{o}F to 1100^{o}F (NJDEP 2004). The auxiliary boiler exhaust temperature of 300^{o}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^{o}F are shown in Table 4-15.

Table 4-15. Other Pollutant Impacts at an Ambient Temperature of 102^{o}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.

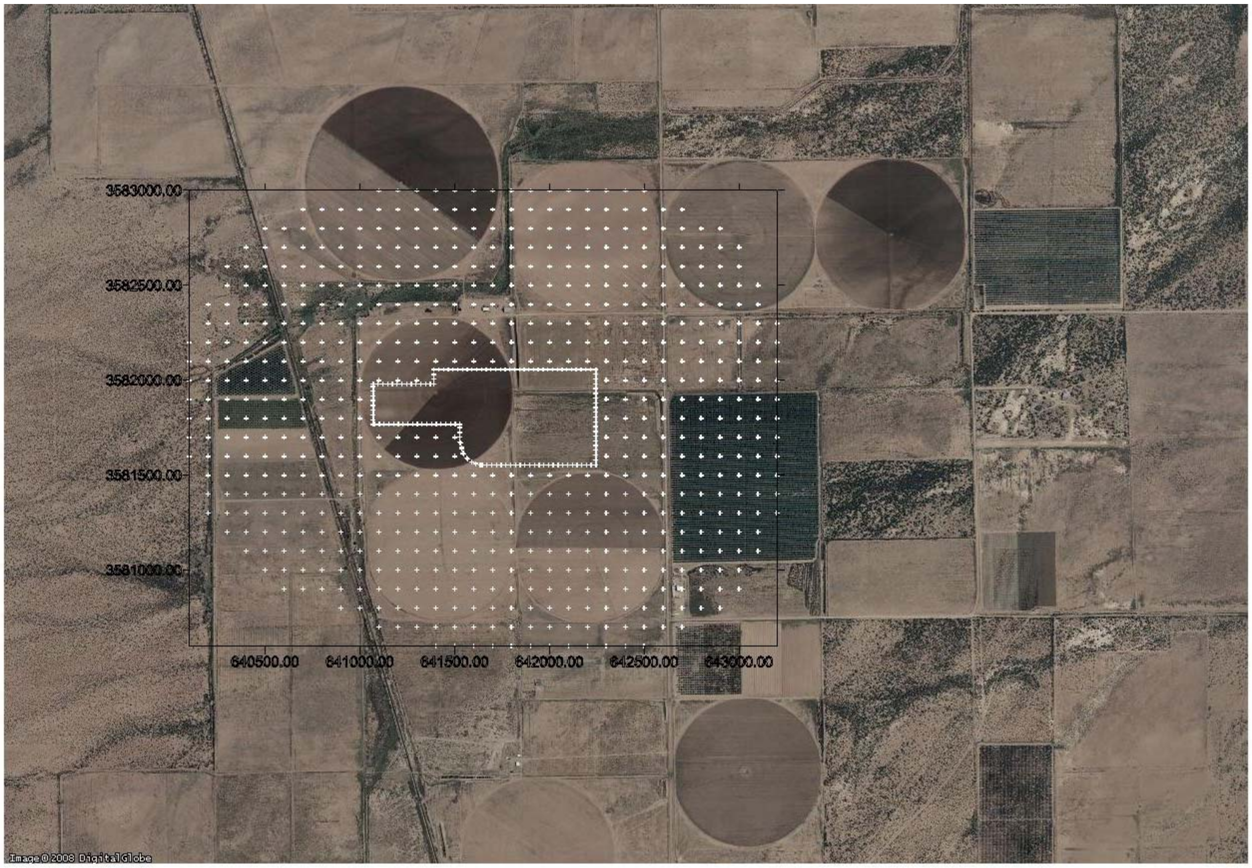

Figure 5-1. Close-in Receptor Grid

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 – Emissions	1-hour, 3-hour – Stack Parameters[b]	8-hour – Emissions	8-hour – Stack Parameters[b]	24-hour – Emissions	24-hour – 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).

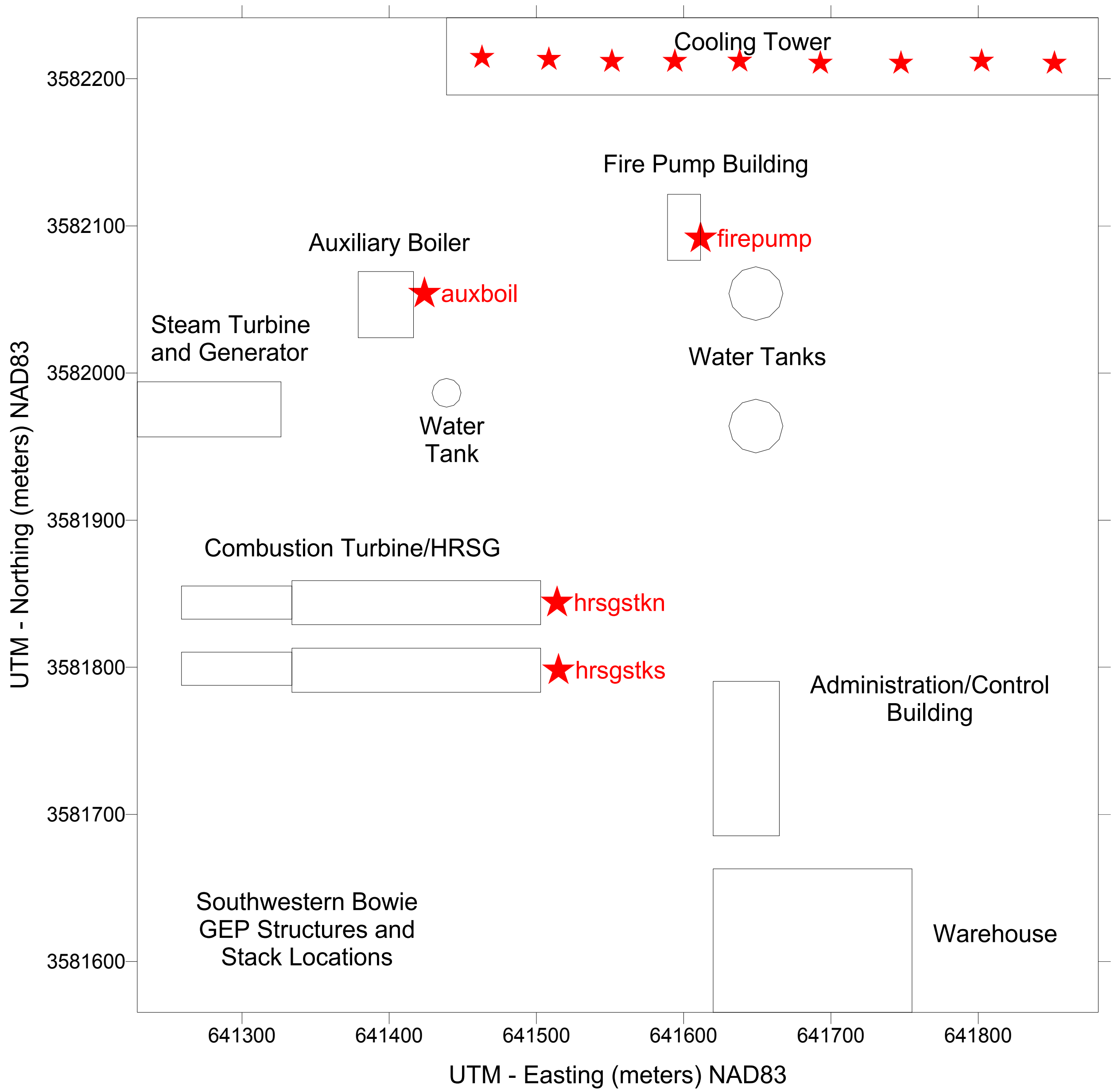

Figure 5-2. Location of Major Emission Points and Structures

Table 5-6. Results of Preliminary Class II Analysis

Averaging Period/ Pollutant	Maximum Predicted Impact (μg/m^3)	Class II Modeling Significance Level (μg/m^3)	Significant Monitoring Level (μg/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:

μg/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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