Montana Department of
ENVIRONMENTAL QUALITY
Brian Schweitzer, Governor
P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

November 2, 2009

Mr. Tim Gregori
Southern Montana Electric Generation and Transmission Cooperative, Inc.
3521 Gabel Road, Suite 5
Billings, MT 59102

Dear Mr. Gregori:

Montana Air Quality Permit #4429-00 is deemed final as of November 1, 2009, by the Department of Environmental Quality (Department). This permit is for the natural gas-fired combustion turbine power generation equipment at the Highwood Generating Station. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-3490

Brent Lignell
Environmental Engineer
Air Resources Management Bureau
(406) 444-5311

VW:BL
Enclosures

Montana Department of Environmental Quality
Permitting and Compliance Division

Air Quality Permit #4429-00

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station Natural Gas Plant
3521 Gabel Road, Suite 5
Billings MT 59102

November 1, 2009

MONTANA AIR QUALITY PERMIT

Issued To: Southern Montana Electric Generation and Transmission Cooperative, Inc. 3521 Gabel Road, Suite 5 Billings MT 59102	Permit: #4429-00 Application Complete: August 3, 2009 Preliminary Determination Issued: August 31, 2009 Department's Decision Issued: October 16, 2009 Permit Final: November 1, 2009 AFS #: 013-0038

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME) for the Highwood Generating Station natural gas plant (HGS gas plant), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

SME proposes to construct, operate and maintain the HGS gas plant, which will consist of two natural gas-fired combustion turbines for electric power generation with a combined net output of approximately 120 megawatts (MW). The facility may be operated in either a simple cycle mode (no heat recovery) or combined cycle mode (heat recovery used to operate a steam powered electric generator). With respect to Prevention of Significant Deterioration (PSD) and Title V programs, the HGS gas plant is a major stationary source. A complete list of permitted equipment is contained in Section I.A of the permit analysis.

B. Plant Location

The facility will be located approximately 8 miles east of Great Falls, Montana. The legal description of the site is Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana; the HGS gas plant is primarily located in Section 25. The approximate universal transverse Mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,266 km (North American Datum of 1927). The approximate latitude/longitude coordinates are latitude 47.55 decimal degrees and longitude -111.03 decimal degrees. The site elevation is approximately 3,310 feet.

SECTION II: Conditions and Limitations

A. Emission Limitations

1. Each turbine shall have one stack dedicated to emissions from simple cycle operation, and a second stack dedicated to emissions from combined cycle operation. Simple cycle stacks shall be at least 80 feet tall from grade; combined cycle stacks shall be at least 105 feet tall from grade (ARM 17.8.749).

2. A commissioning period (as defined in Attachment 3) is provided for the combined cycle operation of any individual turbine, and shall not exceed 16 weeks in duration (ARM 17.8.749).

3. Simple cycle emissions of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) from each simple cycle stack shall not

exceed the following limits on a one-hour basis, where averaging times and definitions of startup, shutdown, steady state, and transient operation are provided in Attachment 3 (ARM 17.8.752):

Pollutant	Simple Cycle Emission Limits (pounds per hour, lb/hr), per stack		
	Startup	Shutdown	Steady State or Transient
NO_x	36.58	36.58	36.58
CO	114.70	114.70	48.96
VOC	3.90	3.90	2.03
SO_2	0.57	0.57	0.57
$PM/PM_{10}/PM_{2.5}$ [a]	4.80	4.80	4.80

a. To be tested as $PM_{2.5}$. If no approved EPA reference test method exists for $PM_{2.5}$, to be tested as PM_{10}.

4. While in simple cycle mode, conveyance or combustion of fuel in each turbine generator shall not exceed 3,200 hours per rolling 12-month period, per turbine, including periods of startup, shutdown, and transient operation (ARM 17.8.749).

5. Any individual simple cycle startup shall not exceed one hour in duration, and any individual simple cycle shutdown shall not exceed one hour in duration (ARM 17.8.752).

6. Combined cycle emissions of NO_x, CO, VOC, SO_2, PM, PM_{10}, and $PM_{2.5}$ from each combined cycle stack shall not exceed the following limits on a one-hour basis, where averaging times and definitions of startup, shutdown, steady state, transient, and commissioning operation are provided in Attachment 3 (ARM 17.8.752):

Pollutant	Combined Cycle Emission Limits (lb/hr), per stack			
	Startup	Shutdown	Steady State or Transient	Commissioning
NO_x	26.12	12.33	4.16	36.58
CO	76.20	4.15	2.03	114.70
VOC	1.86	1.86	1.86	3.90
SO_2	0.69	0.69	0.69	0.69
$PM/PM_{10}/PM_{2.5}$ [a]	7.20	7.20	7.20	7.20

a. To be tested as $PM_{2.5}$. If no approved EPA reference test method exists for $PM_{2.5}$, to be tested as PM_{10}.

7. While in combined cycle mode, conveyance or combustion of fuel in each turbine generator shall not exceed 1,460 startup hours and 730 shutdown hours per rolling 12-month period, per turbine (ARM 17.8.749).

8. Any individual combined cycle startup shall not exceed 2 hours in duration, and any individual combined cycle shutdown shall not exceed one hour in duration (ARM 17.8.752).

9. Emissions of NOx from any stack shall not exceed 25 parts per million dry volume (ppmvd) at 15% oxygen (O2), or 150 nanograms per Joule (ng/J) of useful output (1.2 pound per megawatt-hour, lb/MWh), effective during all periods of operation, including periods of startup, shutdown, transient, and commissioning operation, in accordance with the standards and limitations, and reporting, recordkeeping and notification requirements contained in 40 CFR 60 Subpart KKKK (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart KKKK).

10. Emissions of SO_2 from any stack shall not exceed 110 ng/J (0.90 lb/MWh) gross output, effective during all periods of operation, including periods of startup, shutdown, transient, and commissioning operation; or, SME must not burn in the subject stationary combustion turbines any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2 per million British thermal units, lb/MMBtu) heat input (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart KKKK).

11. SME shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart KKKK (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

12. SME shall operate and maintain the generating units, monitoring equipment, and ancillary equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including periods of startup, shutdown, transient, and commissioning operation, and periods of malfunction (ARM 17.8.340 and 40 CFR 60 Subparts A and KKKK).

13. SME shall install, operate, and maintain only turbines with integrated dry low NO_x (DLN) burners to control NO_x emissions during both simple cycle and combined cycle operation, including periods of startup, shutdown, transient, and commissioning operation (ARM 17.8.752).

14. SME shall utilize good combustion practices and combust only pipeline quality natural gas in each turbine to control PM, PM_{10}, $PM_{2.5}$, NO_x, and SO_2 emissions during both simple cycle and combined cycle operation, including periods of startup, shutdown, transient, and commissioning operation (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart KKKK).

15. SME shall install, operate, and maintain a catalytic oxidizer on each turbine to control CO and VOC emissions during combined cycle operation, including periods of startup, shutdown, transient, and commissioning operation. The catalytic oxidizer shall commence operation within 2 hours of turbine startup and shall continue until 1 hour or less prior to shutdown (ARM 17.8.752).

16. SME shall install, operate, and maintain a selective catalytic reduction (SCR) system on each turbine to control NO_x emissions during combined cycle operation, including periods of startup, shutdown, transient, and commissioning operation. The SCR shall commence operation within 2 hours of turbine startup and shall continue until 1 hour or less prior to shutdown (ARM 17.8.752).

17. For any request to increase the allowable hours of operation in simple cycle mode (Section II.A.4), or to change fuel quality or quantity which may cause an increase in short or long-term emissions, SME shall submit a full PSD permit application complete with a new proposal of the Best Available Control Technology (BACT) as if the HGS gas plant had never been built (ARM 17.8.749).

18. Operation of the 2,206 brake-horsepower (bhp) diesel-fired emergency generator (1500 kilowatt (kW) generator output) and the 343-bhp fire pump shall not exceed 500 hours per unit per rolling 12-month period (ARM 17.8.749 and ARM 17.8.752).

19. SME shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

20. SME shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

21. SME shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.20 (ARM 17.8.749).

B. Testing Requirements

1. For simple cycle operation, SME shall test each turbine generator in simple cycle mode using natural gas to demonstrate compliance with the steady state NO_x and CO emission limits contained in Section II.A.3. Testing shall be conducted concurrently for NO_x and CO within 180 days of initial start-up of each generating unit, and shall conform with the requirements contained in 40 CFR 60, Subpart KKKK. After the initial testing, each generating unit shall be tested annually and the time between tests shall not exceed 14 months since the previous performance test. The Montana Department of Environmental Quality (Department) may approve another testing/monitoring schedule (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart KKKK).

2. For combined cycle operation, SME shall test each turbine generator in combined cycle mode using natural gas to demonstrate compliance with the steady state NO_x and CO emission limits contained in Section II.A.6. Testing shall be conducted concurrently for NO_x and CO within 180 days of initial start-up of each generating unit, and shall conform with the requirements contained in 40 CFR 60, Subpart KKKK. After the initial testing, each generating unit shall be tested annually and the time between tests shall not exceed 14 months since the previous performance test. The Department may approve another testing/monitoring schedule (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart KKKK).

3. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

4. The Department may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. SME shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. SME shall document, by month, the hours and mode of operation for each turbine generator, including startup, shutdown, steady state / transient, and commissioning. By the 25th day of each month, SME shall total the hours of operation for the previous month. The monthly information will be used to verify compliance with the rolling 12-month period limitations in Sections II.A.4 and II.A.7, and the hourly SUSD limits in Sections II.A.5 and II.A.8. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

3. SME shall document, by month, the total hours of operation of the diesel-fired emergency generator and fire pump. By the 25th day of each month, SME shall total the hours of operation of each for the previous month. The monthly information will be used to verify compliance with the rolling 12-month period limitation in Section II.A.18. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

4. SME shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include ***the addition of a new emissions unit***, change in control equipment, stack height, stack diameter, stack exit gas flow, stack exit gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation. The notice must be submitted to the Department, in writing, 10 days prior to startup or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information required in ARM 17.8.745(l)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by SME as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

D. Continuous Emissions Monitoring Systems (CEMS)

1. SME shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK, including requirements for CEMS installation, certification, quality assurance, and relative accuracy and performance testing (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

2. SME shall install, operate, calibrate, and maintain CEMS as follows:

   a. SME shall operate a CEMS consisting of a NOx monitor and a diluent gas (oxygen (O2) or carbon dioxide (CO2)) monitor for the measurement of NO_x on each simple cycle and combined cycle stack, and use the data to monitor compliance with the NO_x emission limits contained in Sections II.A.3 and II.A.6, and the hours of operation limits in Sections II.A.4, II.A.5, II.A.7 and II.A.8. The applicable NO_x CEMS shall be installed and certified within 180 days of initial startup following issuance of MAQP #4429-00 (ARM 17.8.105; ARM 17.8.749; 40 CFR 60, Subpart KKKK; and 40 CFR Parts 72-78).

   b. SME shall operate a CEMS for the measurement of CO on each simple cycle and combined cycle stack, and use the data to monitor compliance with the CO emission limits contained in Sections II.A.3 and II.A.6, and the hours of operation limits in Sections II.A.4, II.A.5, II.A.7 and II.A.8. The applicable CO CEMS shall be installed and certified within 180 days of initial startup following issuance of MAQP #4429-00 (ARM 17.8.105, ARM 17.8.749, and 40 CFR Parts 72-78).

3. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, and excess emissions reported, as per 40 CFR 60, Subpart KKKK, and performance tests conducted in accordance with the requirements of 40 CFR 60, Subpart A; 40 CFR Part 60, Appendix B (Performance Specifications #2, #3, #4 and/or #4A); 40 CFR 60, Subpart KKKK; and 40 CFR Parts 72-78, as applicable (ARM 17.8.749; 40 CFR 60, Subpart KKKK; 40 CFR Part 60; and 40 CFR Parts 72-78).

4. SME shall develop and keep on-site a quality assurance plan for all CEMS (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

5. On-going quality assurance for the CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749 and 40 CFR Part 60, Appendix F).

6. SME shall maintain a file of all measurements from the CEMS and performance testing measurements, including: all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; all adjustments and maintenance performed on these systems or devices. These shall be recorded in a permanent form suitable for inspection and shall be retained on-site for at least 5 years following the date of such measurements and reports. SME shall supply these records to the Department upon request (ARM 17.8.749).

E. Notification

SME shall provide the Department with written notification of the following information within the specified time periods (ARM 17.8.749):

1. Commencement of construction of the HGS gas plant facility within 30 working days after beginning of construction.

2. Actual startup date of each turbine generator for each mode of operation (simple cycle and combined cycle) within 15 working days after the actual startup of each turbine generator for each mode of operation.

SECTION III: General Conditions

A. Inspection – SME shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, Continuous Emissions Rate Monitoring System (CERMS)**)** or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if SME fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving SME of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA, and ARM 17.763.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board).

A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by SME may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

Attachment 1

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Attachment 2

Instructions for Completing Excess Emission Reports (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit startup, shutdown, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as: (1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit startup, shutdown, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as: (1–(CEMS downtime in hours during the reporting period* /total hours of point source operation during reporting period)) x 100

* All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report all excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

EXCESS EMISSIONS REPORT

PART 1

a. Emission Reporting Period _____

b. Report Date _____

c. Person Completing Report _____

d. Plant Name _____

e. Plant Location _____

f. Person Responsible for Review and Integrity of Report _____

g. Mailing Address for 1.f. _____

h. Phone Number of 1.f. _____

i. Total Time in Reporting Period _____

j. Total Time Plant Operated During Quarter _____

k. Permitted Allowable Emission Rates: Opacity _____

SO2 _____ NOx _____ TRS _____

l. Percent of Time Out of Compliance: Opacity _____

SO2 _____ NOx _____ TRS _____

m. Amount of Product Produced During Reporting Period _____

n. Amount of Fuel Used During Reporting Period _____

PART 2 – Monitor Information (Complete for each monitor).

a. Monitor Type (circle one): Opacity SO2 NOx O2 CO2 TRS Flow

b. Manufacturer _____

c. Model No. _____

d. Serial No. _____

e. Automatic Calibration Value: Zero _____ Span _____

f. Date of Last Monitor Performance Test _____

g. Percent of Time Monitor Available:

1) During reporting period _____

2) During plant operation _____

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values _____

_____

i. Conversion Factor (f-Factor, etc.) _____

j. Location of monitor (e.g. control equipment outlet)_____

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one): Opacity SO2 NOx TRS

b. Type of Control Equipment _____

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)_____

_____

d. Date of Control Equipment Performance Test _____

e. Control Equipment Operating Parameter During Performance Test _____

_____

_____

_____

_____

PART 4 – Excess Emission (by Pollutant)
Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 – Continuous Monitoring System Operation Failures
Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 – Control Equipment Operation During Excess Emissions
Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 – Excess Emissions and CEMS performance Summary Report
Use Table IV: Complete one sheet for each monitor.

PART 8 – Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE _____

NAME _____

TITLE _____

DATE _____

TABLE I

EXCESS EMISSIONS

Date	Time			Magnitude	Explanation/Corrective Action
	From	To	Duration		

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time			Problem/Corrective Action
	From	To	Duration	

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time			Operating Parameters	Corrective Action
	From	To	Duration		

TABLE IV

EXCESS EMISSIONS AND CEMS PERFORMANCE SUMMARY REPORT

Pollutant (circle one): SO2 NOx TRS H2S CO Opacity

Monitor ID _____

Emission data summary [1]	CEMS performance summary [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 =$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 =$

1. For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
2. CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Attachment 3

Definition of Operating Conditions, MAQP #4429-00

Dispatched Power Set-Point – The electricity generation level to be transmitted to the grid as requested by SME and approved by the grid operator. The grid operator instructs the plant to startup and go to the desired megawatt output level (i.e., dispatched set-point). If the generation load is not needed a shutdown is requested by SME and approved by the grid operator who then instructs the plant to shutdown.

Simple Cycle Startup – Any process that begins with the introduction of fuel into a combustion turbine (i.e., from fuel no-flow to fuel flow condition) following hydraulic spin-up and ends when the dispatched power set-point is reached, where turbine combustion emissions are vented to a simple cycle stack upstream of the heat recovery steam generator. Any individual simple cycle startup shall not exceed one hour in duration. The averaging time for compliance with startup emission limits is one hour. The emission limit applies to any clock hour in which any part of a startup event occurs.

Simple Cycle Shutdown – Any process that begins when the turbine initiates a transition from a final dispatched power set-point and ends when fuel is cut off to the combustion turbine, where turbine combustion emissions are vented to a simple cycle stack upstream of the heat recovery steam generator. Any individual shutdown shall not exceed one hour in duration. The averaging time for compliance with shutdown emission limits is one hour. The emission limit applies to any clock hour in which any part of a shutdown event occurs.

Simple Cycle Steady-State/Transient Operation – Any process in which fuel is combusted in the turbine and emissions are vented to a simple cycle stack upstream of the heat recovery steam generator, excluding startup or shutdown operation as defined above, but including periods of time in which a combustion turbine transitions between non-zero power set-points. The averaging time for compliance with steady-state/transient emission limits is one hour. The emission limit applies to any clock hour in which any part of a startup or shutdown does not occur.

Combined Cycle Startup – Any process that begins with the introduction of fuel into a combustion turbine (i.e., from fuel no-flow to fuel flow condition) following hydraulic spin-up and ends when the dispatched power set-point is reached, excluding any commissioning period as defined below, where turbine combustion emissions are vented to a combined cycle stack downstream of the heat recovery steam generator, catalytic oxidizer, and SCR. Any individual combined cycle startup shall not exceed two hours in duration. The averaging time for compliance with startup emission limits is one hour. The emission limit applies to any clock hour in which any part of a startup event occurs.

Combined Cycle Shutdown – Any process that begins when the turbine initiates a transition from a final dispatched power set-point and ends when fuel is cut off to the combustion turbine, excluding any commissioning period as defined below, where turbine combustion emissions are vented to a combined cycle stack downstream of the heat recovery steam generator, catalytic oxidizer, and SCR. Any individual combined cycle shutdown shall not exceed one hour in duration. The averaging time for compliance with shutdown emission limits is one hour. The emission limit applies to any clock hour in which any part of a shutdown event occurs.

Combined Cycle Steady-State/Transient Operation – Any process in which fuel is combusted in the turbine and emissions are vented to a combined cycle stack downstream of the heat recovery steam generator, catalytic oxidizer, and SCR, excluding any commissioning period as defined below, excluding startup or shutdown operation as defined above, but including periods of time in which a combustion turbine transitions between non-zero power set-points. The averaging time for compliance with steady-state/transient emission limits is one hour. The emission limit applies to any clock hour in which any part of a startup or shutdown does not occur.

Combined Cycle Commissioning – The process that begins with the first episode of fuel combustion in a turbine undergoing combined cycle operation, following any time a new or refurbished turbine or catalyst is installed or re-installed at the facility. The commissioning period for an individual turbine shall not exceed 16 weeks following the first episode of fuel combustion in the affected turbine. The commissioning period applies to combined cycle operation only since there are no post-combustion controls to adjust for simple cycle operation.

Permit Analysis
Southern Montana Electric Generation and Transmission Cooperative, Inc. –
Highwood Generating Station Natural Gas Plant
Montana Air Quality Permit #4429-00

I. Introduction/Process Description

Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME) proposes to construct, operate and maintain the Highwood Generating Station natural gas plant (HGS gas plant). The HGS gas plant will consist of two natural gas-fired combustion turbines for electric power generation, with combined net output of approximately 120 megawatts (MW), including heat recovery. The facility may be operated in either a simple cycle mode (no heat recovery) or combined cycle mode (heat recovery used to operate a steam power electric generator). The facility will be located approximately 8 miles east of Great Falls, Montana. The legal description of the site is Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana.

A. Permitted Equipment

The proposed facility would consist of two combustion turbine generators each with duct firing and a heat recovery steam generator (HRSG), a third steam turbine generator that utilizes heat output from the two combustion turbines, three grouped cooling towers, miscellaneous building heaters, a black-start emergency generator, and an emergency fire pump.

The proposed generating units for the HGS gas plant are two General Electric LM6000PF Dry Low Emissions (DLE) combustion turbines (DLE is the turbine manufacturer term for Dry Low NOx burners or DLN). The LM6000PF is a simple cycle combustion unit containing one aeroderivative combustion turbine and a single shaft-driven electric generator. Within each combustion turbine, combustion air is compressed and mixed with fuel, then fired in the combustor to produce compressed hot combustion gases. Expansion of these gases in the turbine rotates the turbine shaft, which turns a generator to produce electricity. Each of the two LM6000PF generating units is rated at approximately 43 MW at 100% load at 54.7 degrees Fahrenheit (°F) ambient temperature. Including the electricity generated from the heat recovery steam generators and steam turbine, the plant gross total is approximately 120 MW. Pipeline quality natural gas is the selected operations and startup fuel.

In addition to the power block, other tanks and machinery will be installed at this facility. A black-start emergency generator and fire pump will be installed, both diesel-powered. Aqueous ammonia will be stored in above-ground horizontal tanks for use in the Selective Catalytic Reduction (SCR) air pollution control device that has been selected as best available control technology (BACT) for control of nitrogen oxides (NO_x) emissions during combined cycle operation, as detailed in Section III.

Cooling towers will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling towers. The proposed cooling towers will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling towers will be approximately 394 gallons per minute (gpm).

SME plans to construct the facility in two phases. Phase I includes the construction and operation of two natural gas-fired turbines to operate in simple cycle mode. In Phase II, SME will add duct burners, heat recovery equipment and a steam-driven turbine to make the facility a combined cycle system. During initial Phase I service (defined as operations before the HRSG and steam plant are installed), permit conditions will limit the hours of simple cycle operation to 3,200 hours per year, including startup and shutdown time. During Phase II, following the installation of the

steam plant, the simple cycle hours of operation will maintain a limit of 3,200 hours per year, and combined cycle operation will include a limit on startup and shutdown time. However, Phase II will not limit steady state operation in combined cycle mode. SME proposed to permit the facility for continuous combined cycle operation of both generating units to service all eventualities including an emergency electrical power demand.

For simple cycle operation, proper design and operation, and the use of pipeline quality natural gas, will control emissions of sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). SME is required by permit to combust only pipeline quality natural gas, which will result in reduced SO_2 and $PM_{10}/PM_{2.5}$ emissions. DLN will control NO_x emissions. The 3,200 hour annual limit on operations will also limit emissions while in simple cycle mode.

For combined cycle operation, SCR will control post-combustion exhaust emissions of NO_x, and catalytic oxidation will control post-combustion exhaust emissions of carbon monoxide (CO) and volatile organic compounds (VOC). DLN burners will also contribute to reduced CO and VOC emissions by leaning out the air fuel mixture. Proper design and operation, and the use of pipeline quality natural gas, will control emissions of SO_2 and $PM_{10}/PM_{2.5}$. Permit conditions limit the number of hours per year that the facility is in startup or shutdown mode during combined cycle operation.

B. Facility History

On March 30, 2006, the Department of Environmental Quality (Department) issued a preliminary determination on Montana Air Quality Permit (MAQP) #3423-00 for the HGS coal plant, and accepted comments on the preliminary determination through May 1, 2006. On April 25, 2006, Bison Engineering, Inc. (Bison), on behalf of SME-HGS, verbally notified the Department of additional emitting units that were not previously analyzed and permitted under the preliminary determination and were deemed necessary for the construction and operation of the circulating fluidized bed (CFB) Boiler. Specifically, SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS would need to operate portable/temporary propane-fired heaters for the purpose of curing the CFB Boiler refractory brick. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006, and the Department issued a supplemental preliminary determination on MAQP #3423-00 to include the new units. The Department's supplemental preliminary determination was issued as an attachment to the Draft Environmental Impact Statement (DEIS), which was published on June 30, 2006, and was therefore subject to public comment in accordance with the applicable DEIS timeframes. The only changes to the initial preliminary determination under the supplemental preliminary determination were related to the refractory brick curing heaters and administrative errors contained in the initial preliminary determination on MAQP #3423-00.

Based on comments received during the public comment period on the Department's initial preliminary determination and additional comments received on the Department's supplemental preliminary determination during the DEIS comment period, the Department's final decision on MAQP #3423-00 included the following changes:

- Modification of the mercury emission control requirements.
- Modification of the CFB Boiler Start-Up and Shutdown Plan.
- Modification of CFB Boiler Start-Up and Shutdown requirements.
- Removal of the Start-Up and Shutdown CO emission limit.
- Modification to include propane as an allowable CFB Boiler start-up and shutdown fuel.

- Modification of the language to clarify the applicable BACT-determined emission control requirements for the affected material handling transfer points.
- Modification of the source testing schedule for material handling baghouses.
- Removal of the term "belt" from the conveyor transfer requirement in Section II.E.5.
- Modification to remove the requirement that all limestone haul trucks be "covered" during transport.
- Removal of the language "…for transfer to the on-site ash monofill/landfill" from Section II.G.4.
- Inclusion of the language "…by manufacturer's design…" to Section II.K.2, because the existing condition contained in the Department's preliminary determination on MAQP #3423-00 was not practically enforceable, as written.
- Removal of the language "…or according to another testing/monitoring schedule as may be approved by the Department in writing" from Section II.N.1.a, b, d, and f, as the Department does not have the authority to require a less stringent testing schedule than that required under 40 CFR Part 60.
- Inclusion of the language "…SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained" to Section II.N.1.a, d, f, and j.
- Inclusion of 40 CFR Part 60, Appendix B, Performance Specification #12A, to Section II.P.3.
- Modification of Section III.H, Construction Commencement, to require that construction commence within 18 months of permit issuance.
- Correction of various administrative errors contained in the initial and supplemental preliminary determination(s) on MAQP #3423-00.
- Update to the Ambient Impact Analysis contained in Section VI of Permit Analysis to include modeling based on the proposed change in plant footprint to mitigate impacts to the Lewis and Clark historical portage recognized through the EIS process.
- Removal of all requirements and references to the Acid Rain Program under 40 CFR Parts 72-78.

The HGS coal plant air quality permit was appealed to the Montana Board of Environmental Review (BER) prior to being issued final on May 30, 2007. The BER ruled on April 21, 2008, that MAQP #3423-00 should be remanded to the Department to complete a Best Available Control Technology (BACT) analysis for $PM_{2.5}$. The BER issued their final order on May 30, 2008, stating that "Permit No. 3423-00 is remanded for a thorough top-down BACT analysis of $PM_{2.5}$ of the CFB boiler. A surrogate analysis for $PM_{2.5}$ is not acceptable. A top-down BACT analysis conforming to the NSR Manual will be deemed to be sufficiently thorough."

On June 6, 2008, the Department received an "Addendum to Application for Air Quality and Operating Permits" from SME for MAQP #3423-00. The addendum application included a proposed BACT determination for $PM_{2.5}$. On September 29, 2008, the Department received a revised addendum application, and the Department determined the application materials complete.

MAQP #3423-01 was issued as a preliminary determination on October 6, 2008, and the public comment period closed on November 5, 2008. The preliminary determination established permit limitations, conditions and reporting requirements in accordance with the results of the ordered $PM_{2.5}$ specific top-down BACT determination for the CFB Boiler. Additionally, SME requested in the application to take federally enforceable permit limits for hazardous air pollutants (HAPs) in order to avoid major source status with respect to HAPs. Pursuant to this request, emission limitations were included for hydrochloric acid (HCl), hydrofluoric acid (HF), as well as, boiler heat input rate and control technology requirements. The Department received a multitude of comments on the preliminary determination. In response to comments, the Department made the boiler heat input, HCl, and HF limitations more stringent to further ensure that SME's potential

emissions would fall below the major source threshold for HAPs. The Department also increased the testing frequency for these pollutants to annually. On November 26, 2008, MAQP #3423-01 pursuant to the Order issued by the BER in the matter of contested case number BER 2007-07 AQ became final.

On August 3, 2009, SME sent a letter to the Department stating that SME would voluntarily rescind MAQP #3423-01 to the Department. Pursuant to SME's request, the Department sent a letter to SME to revoke MAQP #3423-01; SME received the letter on August 4, 2009. Following a 15-day appeal period, revocation of MAQP #3423-01 became final on August 20, 2009.

C. Response to Public Comments

The Department received comments on the permit, permit analysis, and draft EA. Comments were submitted by five individuals (two of whom submitted comments jointly), the Montana Preservation Alliance (MPA), the National Trust for Historic Preservation, the Montana Environmental Information Center (MEIC), the National Park Service (NPS), the Sierra Club (SC), the Great Falls Chamber of Commerce (COC), the Great Falls Development Authority (DA), Western Environmental Trade Association (WETA), and Bison Engineering, Inc. on behalf of SME (SME).

The comments are shown below, summarized and grouped by topic. The Department response follows each comment, or group of comments if the issues were similar

ISSUE PERMIT

Comment: Commenter supports the construction of the proposed facility and issuance of permit. [Great Falls Chamber of Commerce, Great Falls Development Authority, WETA] The energy produced will play a key role in the economies of the communities served. The good paying jobs during construction and to operate the facility will be a boost to workers and the local economy. The facility will also mean an increase in the property tax base. [WETA 9/30/09]

> ***Response:*** The Department acknowledges the comments in support of the permit action; however, the Department is required by statute to issue or deny permits based solely on compliance with Federal and Montana Clean Air Act (CAA) regulations.

DENY PERMIT

Comment: Deny the permit, or at a minimum, demonstrated compliance with the National Historic Preservation Act should be required prior to issuing the permit. [NPS 6/11/09]

> ***Response:*** The Department acknowledges the comment in opposition to the permit action; however, the Department is required by statute to issue or deny permits based solely on compliance with Federal and Montana Clean Air Act regulations.

Comment: The Gessaman letter (copy attached) covers all the salient points regarding why this permit application should be rejected as currently proposed. I as a Montana citizen and taxpayer fully concur and support all the Gessaman's arguments on this matter. Please add my name to your list of opponents to the issuance of this permit for the reasons so eloquently outlined. [Taylor 9/30/09]

> ***Response:*** The Department acknowledges the comment in opposition to the permit action; however, the Department is required by statute to issue or deny permits based solely on compliance with Federal and Montana Clean Air Act regulations.

Comment: Valuable farmland is/will be destroyed, compromising Montana's open spaces. Project would be much more acceptable if built on previously developed land; e.g., Great Falls ACM smelter site. Project is unneeded with little benefits. Request that permits be denied. [Mayernik 9/30/09]

Response: The Department acknowledges the comment in opposition to the permit action; however, the Department is required by statute to issue or deny permits based solely on compliance with Federal and Montana Clean Air Act regulations.

ANALYZE/REPRESENT CO2 EMISSIONS

Comment: Proposed EA, pg. 17, 4.2.2 Air Quality Impacts. Total worst case coal plant plus gas plant CO2 emissions should be presented. [NPS 6/11/09]

Response: This comment was submitted prior to revocation of the HGS coal plant permit, MAQP #3423-01. Because the coal plant permit has been revoked, CO_2 emissions will remain as reported to only reflect gas plant emissions.

Comment: DEQ must conduct a Best Available Control Technology (BACT) analysis and establish an emission limit for CO_2 in this permit and should require the monitoring of CO_2 emissions as it has done at two other similar facilities in the last year. 500,000 tons of CO_2 will be emitted by the facility each year. The total is significantly more than a similarly sized facility recently permitted for Basin Electric, the Culbertson Generating Station. Why? Carbon dioxide is both a pollutant under the law and a regulated pollutant within the meaning of the both the federal and Montana CAA's. This permit should also include an alternatives analysis under MEPA that would result in lower CO_2 emissions. [MEIC 9/30/09]

Response: RE: DEQ must conduct a CO_2 BACT analysis and establish a CO_2 emission limit

Until rules regulating greenhouse gas (GHG) emissions are finalized and codified, the Department has neither the authority nor guidance to implement control of CO_2 emissions. However, recent activity has taken steps toward the development of GHG regulation:

On April 2, 2007, the Supreme Court found that GHGs, including carbon dioxide, are air pollutants covered by the CAA [*Massachusetts v. EPA*, 549 U.S. 497 (2007)]. The Supreme Court found that EPA was required to determine whether or not emissions of GHGs from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In April 2009, EPA responded to the Court by proposing a finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. [*http://www.epa.gov/NSR/fs20090930action.html*]

On September 30, 2009, EPA announced a proposal focused on large facilities emitting over 25,000 tons of greenhouse gases a year. These facilities would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule proposes new thresholds for GHG emissions that define when CAA permits under the New Source Review (NSR) and title V operating permits programs would be required for new or existing industrial facilities. The proposed thresholds would cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from power plants. The EPA is in the midst of a 60-day comment period on this proposal. [*http://www.epa.gov/NSR/fs20090930action.html*]

The final emissions thresholds for GHG emissions under the federal PSD and operating permit programs will take effect immediately upon promulgation of the final rule. At that time, EPA will put the new thresholds into effect in state, local and tribal agency programs that run PSD and Title V operating programs under EPA approval. States that have State Implementation Plan-approved PSD programs and/or approved Title V programs, including Montana, are reviewing potential impacts to permitting and what rule changes may be warranted in light of probable CO_2 regulation in the Federal Clean Air Act. Those agencies will continue to have the option to seek EPA approval for lower thresholds if they demonstrate that they can adequately implement the PSD program at the lower thresholds. [*http://www.epa.gov/NSR/fs20090930action.html*]

Thus, until these rules are finalized, the Department applies BACT pursuant to ARM 17.8.752, (as defined in ARM 17.8.740(2), where "BACT" is specific to each pollutant subject to 42 USC 7410, et seq., or MCA 75-2-101, *et seq*.) and pursuant to ARM 17.8.819 (as defined in ARM 17.8.801(6), where "BACT" is specific to pollutants regulated under the Federal Clean Air Act (FCAA), excluding Hazardous Air Pollutants). Neither the FCAA or the Montana Clean Air Act currently reference CO_2.

Response: RE: Permit should require monitoring of CO2 emissions

The Department acknowledges that a clarification of monitoring requirements would be helpful. Therefore, the Department has revised permit condition II.D.2.a to require monitoring of *either* oxygen *or* carbon dioxide.

The Department would like to clarify that, contrary to the comment, CO_2 monitoring is not required for the Basin Electric Culbertson Generating Station (MAQP #4256-00) or the NorthWestern Energy Mill Creek Generating Station (MAQP #4255-00). Each permit requires, pursuant to 40 CFR 60, Subpart KKKK, installation of a continuous emission monitoring system (CEMS) to measure NOx and *either* oxygen (O_2) *or* carbon dioxide (CO_2). Thus, the facility must monitor oxygen or carbon dioxide, but may decide which gas is monitored. The draft MAQP #4429-00 for the HGS gas plant had the similar condition under II.D.2.a requiring installation of a NO_X CEMS and compliance with all applicable requirements of 40 CFR 60, Subpart KKKK.

Response: RE: Why are facility CO2 emissions significantly larger than those from the Basin Electric, Culbertson Generating Station?

CO_2 emissions are in direct, linear relationship to the amount of natural gas combusted; i.e., the more gas combusted, the more CO_2 formed. Fundamentally, *potential* CO_2 emission from the SME gas plant are higher because the facility can potentially burn more natural gas – it is permitted to run all year (8,760 hours in combined cycle mode), whereas the Basin Electric facility is permitted to operate 3,400 hours. Also, the SME facility is capable of burning more natural gas than the Basin Electric facility at any given time to due equipment capacity. These differences are highlighted in the following table.

Facility	Capacity (MW)	Maximum Operation (hours/year)	Maximum Generation (MWh)	Max Heat Input To Turbines (MMBtu/hr)	Max Annual Energy Input (MMBtu)	Maximum Facility Natural Gas Combusted (scf) (1)
SME	120	8,760	1,051,200	895 (2)	7,840,200	7,686,470,588
Basin	100	3,400	340,000	738 (3)	2,509,200	2,460,000,000

1. Based on the higher heating value of natural gas, 1,020 Btu/scf.
2. Value reflects total heat input contained in the natural gas combusted in two turbines and two duct burners.
3. Value reflects total heat input contained in the natural gas combusted in the one, and only, turbine.

Thus, the SME gas plant has the potential to use over three times the amount of natural gas, yet produces over three times the amount of electricity. That said, actual gas consumption is likely to be less than that consumed at the permitted maximum hours of operation.

BROADEN BACT SCOPE AND REQUIRE ADDITIONAL CONTROLS

Comment: The DEQ should not rely on an EPA Region 4 analysis of BACT determinations with no reference to recent decisions in Montana (NWE #4255-00 and Basin Electric #4256-00). The law requires BACT analyses to review and compare recent permitting decisions for similar sources, and that should include recent DEQ decisions on similar natural gas plants. [MEIC 9/30/09]

Response: The Department agrees that the analysis of Montana facilities should have been presented prominently in the BACT analysis. In developing the Preliminary Draft permit, similar Montana facilities were scrutinized for their use of emission controls, in addition to comparison with Region 4 and RBLC data. The following tables compare emission controls and limits to the following natural gas-fired combustion turbines in Montana:

MAQP #4256, Basin Electric, Culbertson Station
MAQP #4255, Northwestern Energy, Mill Creek Station
MAQP #3154, Montgomery Great Falls Energy Partners, Great Falls Station

COMBINED CYCLE

Permit No.	Equipment and Power Output	Hours per Year	Control Technology and Emission Limits			
			NOx (1)	CO (2)	VOC (2)	PM
4429	2 – GE LM6000, 43 megawatt (MW) ea, plus heat-recovery steam generator and steam turbine for 120 MW total	8,760 per Turbine	DLN, SCR; 4.16 lb/hr, 1-hr avg	CATOX; 2.03 lb/hr, 1-hr avg	CATOX; 1.86 lb/hr, 1-hr avg	7.2 lb/hr, 1-hr avg
3154	2 – GE PG7121EA, 80 MW ea, plus heat-recovery steam generator and steam turbine for 262 MW total	15,240 Combined	DLN, SCR; 8.9 lb/hr, 30-day roll avg; 9.7 lb/hr, 1-hr avg	CATOX; 10.9 lb/hr, 30-day roll avg; 11.8 lb/hr, 1-hr avg	CATOX; 2.7 lb/hr, 1-hr avg	PM10 turb only 10.0 lb/hr, 1-hr avg; turb + duct burner 11.2 lb/hr, 1-hr avg

1. DLN = dry low NOx burners; SCR = selective catalytic reduction
2. CATOX = catalytic oxidation

SIMPLE CYCLE

Permit No.	Equipment and Power Output	Hours per Year	Control Technology and Emission Limits			
			NOx (1)	CO (2)	VOC (2, 3)	PM (3)
4429	2 – GE LM6000, 43 MW ea; 86 MW total	3,200 per turbine	DLN; 36.58 lb/hr, 1-hr avg	None; 48.96 lb/hr, 1-hr avg	None; 2.03 lb/hr, 1-hr avg	4.8 lb/hr, 1-hr avg
4256	1 – GE LMS100, 100 MW	3,400	WI; 78.50 lb/hr, 1-hr avg; 25 ppm	CATOX; 21.50 lb/hr, 3-hr avg	CATOX; 1.33 lb/hr, 1-hr avg	6.0 lb/hr, 1-hr avg
4255	4 – Pratt & Whitney FT8 Swiftpac Units, ea unit has 2 turbines on one 49.6 MW generator; 200 MW total	No Limit (8,760 hrs)	WI, SCR; 11.07 lb/hr, 30-day roll avg	CATOX; 10.78 lb/hr, 30-day roll avg	CATOX; 2.47 lb/hr, 30-day roll avg	7.30 lb/hr, 30-day roll avg
3154	2 – GE PG7121EA, 80 MW ea, 160 MW total, 2 yr operation limit	4,620 Combined	DLN; 39.3 lb/hr, 4-hr roll avg; 34.9 lb/hr, 1-hr avg	None; 34.8 lb/hr, 30-day roll avg; 21.3 lb/hr, 1-hr avg	None; 8.1 lb/hr, 30-day roll avg; 9.5 lb/hr, 1-hr avg	
3154	2 – Rolls Royce Trent 60, 64 MW ea; 129 MW total	1,752 per turbine	WI, SCR; 13.75 lb/hr	CATOX; 6.28 lb/hr		15.04 lb/hr or 5.41 tpy

1. DLN = dry low NOx burners; WI = water injection; SCR = selective catalytic reduction
2. CATOX = catalytic oxidation
3. Blank cells indicate no limit in permit.

Compared to the combined cycle units at Montgomery Great Falls Energy Partners, Great Falls Station (MAQP #3154), the SME gas plant combined cycle limits are lower for all pollutants, while utilizing the same type of emission controls.

Compared to the simple cycle unit at Basin Electric, Culbertson Station (MAQP #4256), the SME gas plant simple cycle limits are lower for NOx and PM, but higher for CO and VOC. The Culbertson Station controls CO and VOC with catalytic oxidation, which was not considered BACT for the SME gas plant due to adverse cost impacts. Catalytic oxidation was more cost efficient at Culbertson because the unit is much larger (100 MW vs. 43 MW) and exhibited significantly higher uncontrolled CO emissions at 215.26 lb/hr. Also, Culbertson was permitted for slightly more hours per year which would mean even more potential CO emissions. These factors contributed to more cost effective controls when considered on a cost-per-ton basis. Note that VOC control was not cost effective for either facility, but since VOC is controlled by same mechanisms as CO control, VOC reduction is an added benefit.

Compared to the simple cycle units at Northwestern Energy, Mill Creek Station (MAQP #4255), the SME gas plant simple cycle limits are lower for VOC and PM, but higher for NOx and CO. The Mill Creek Station controls NO with SCR and CO with catalytic oxidation, neither of which was considered BACT for the SME gas plant due to adverse cost impacts. SCR and catalytic oxidation were more cost efficient at Mill Creek because the facility is permitted for 8,760 hours per year which would mean significantly more potential emissions. This factor contributed to more cost effective controls when considered on a cost-per-ton basis. Also, the Mill Creek facility limits are based on 30-day rolling average, which would allow much higher emission spikes compared to the hourly average at the SME gas plant. The Mill Creek facility regulates potentially unstable wind turbine power generation, and therefore needed this flexibility due to moderate delivery of power to the grid.

Compared to the 80 MW GE simple cycle units at Montgomery Great Falls Energy Partners, Great Falls Station (MAQP #3154), the SME gas plant simple cycle limits are lower for VOC, but higher for NOx and CO. The Montgomery Station controls NOx using the same technology as the SME gas plant; i.e., dry low NOx burners (DLN). Hourly emissions are only slightly higher at SME 36.58 lb/hr, compared to 34.9 lb/hr at Montgomery. Thus, the selection of BACT is the same for each facility, and the small differences in hourly emission

may be attributable to different turbine capacity (80 MW vs. 43 MW) and design. Neither facility uses add-on controls for CO, so again BACT selection is the same. Differences in hourly emission may be attributable to different turbine capacity and design, where larger turbines often see efficiency gains resulting in lower emission rates.

Compared to the 64 MW Trent simple cycle units at Montgomery Great Falls Energy Partners, Great Falls Station (MAQP #3154), the SME gas plant simple cycle limits are lower for PM, but higher for NOx and CO. The Montgomery Station controls NOx using SCR and CO using catalytic oxidation, neither of which was considered BACT for the SME gas plant due to adverse cost impacts. Montgomery proposed the most stringent controls in their application and did not provide economic information; however, such a control scheme would probably have a differing economic impact on different types of turbines and BACT is determined on a case-by-case basis considering plant and unit specific information.

The controls and limits at the SME gas plant are consistent with BACT determinations statewide and nationwide. Therefore, permit conditions will remain as written.

Comment: DEQ should include as part of the BACT analysis the incremental cost of SCR in the single cycle analysis excluding the cost of installing the SCR. The BACT analysis found SCR to be cost ineffective for single cycle operations because it assumed the entire cost would be attributed to the single cycle cost analysis. This is not valid. When Phase II of the project is complete, SCR will be required for the combined cycle operation. At this point the DEQ should require the use of SCR during the single cycle operation as well. Failure to require the use of SCR during operation of single cycle operations when the equipment is sitting idle is to forego an opportunity to prevent significant deterioration of air quality. [MEIC 9/30/09]

Response: The Department agrees this would be an appropriate analysis and submits the following:

In order to consider the incremental cost of applying a combined cycle SCR system to simple cycle operation, the analysis has to assume that turbine exhaust is routed through a single emission control system (i.e., through the same SCR) regardless of whether the facility operates in simple cycle or combined cycle mode. Routing emissions through a single control system poses certain technical challenges during simple cycle operation. It is necessary to first describe these challenges because the manner in which they are overcome has a direct impact on the associated costs.

Efficient steam generator design involves maximized heat transfer surfaces and thin steam generator tubes. During combined cycle mode, the turbine exhaust gases flow across the metal components of the steam generator in which water circulates, converting the water into steam. A significant portion of the energy contained within the turbine exhaust is transferred to the steam in the steam generator. Because the phase change from water to steam uses the energy content of the turbine exhaust, the steam generator components would not experience the full thermal load of the high-temperature exhaust gas. In contrast, when rapid startup and load-following operations require simple cycle mode, the water would not be circulating because simple cycle mode does not generate steam. Thus, water would be absent from within the metal components of the steam generator, and these components would be subject to the full thermal load of the high-temperature exhaust gas. Materials capable of withstanding these higher temperatures would be more expensive than materials for which the thermal impacts are mitigated by the circulating water. Thus, materials capable of withstanding simple cycle exhaust conditions would be more expensive than materials designed to accommodate only combined cycle operation.

This more robust design was analyzed in Section 5.4.4.3 of the permit application, configuration "S2", the "once through steam generator" (OTSG). The OTSG would be able to withstand the direct heat from turbine exhaust during simple cycle operation, and would still allow for rapid start up time, which is the defining beneficial characteristic of simple cycle operation (i.e., to quickly send power to the grid during peak demand). The cost-effectiveness (dollars per ton of NOx removed) for the OTSG system based on 8,760 hours of combined cycle operation was $12,953/ton, which was considered disproportionately adverse relative to other recent BACT determinations. Conversely, the baseline design configuration "T1" utilized an SCR system dedicated only for combined cycle operation (and consequently would not require more robust components). For design T1, the cost-effectiveness was $3,013/ton, and was determined to be BACT during combined cycle operation.

A simple and conservative approach for estimating the incremental cost for a system that could accommodate simple cycle operation would be to attribute the difference in above costs to the need for more robust components. This difference, from T1 to S2 (both combined cycle), is $9,940/ton, based on Table 5-5 in the permit application. This approach is conservative for several reasons. First, it is calculated based on 8,760 hours of operation. The simple cycle limit is 3,200 hours per year, which means less NOx is emitted over 3,200 hours in contrast to the amount emitted over 8,760 hours. Thus fewer emissions would actually be allocated to the cost of control calculation. Second, simple cycle operation would not require firing of duct burners, further reducing NOx formation. And finally, more expensive SCR catalysts would be required to withstand the high-temperature exhaust gas, driving up the cost of control. Collectively, these factors would increase the cost-per-ton calculation because the cost would be higher and the tons-reduced would be smaller. At a minimum of $9,940/ton, the cost of utilizing SCR for simple cycle control is considered disproportionately adverse. Therefore, the permit conditions remain as written.

One additional note: During development of the draft permit, the Department requested that SME provide an additional analysis of a design configuration in which two turbines routed emissions to a common SCR system. The Department made this request to explore cost efficiencies that might be achieved by taking advantage of common catalyst infrastructure, as well as to contrast the design with other turbine facilities in Montana. On behalf of SME, Bison Engineering provided an economic screening analysis based on the following assumptions:

1) The amount of catalyst required will not change because the same amount of exhaust flow and pollutant loading exists with either configuration.

2) The required catalyst can be "shoehorned" into a similar sized frame, and no additional equipment is necessary; therefore, those costs will be shared between the turbines (i.e., the cost of the whole SCR system minus the catalyst would be halved). This conservative assumption results in a potential $366,000 savings.

3) The same volumes of ammonia would be required, as the flowrates and pollutant loadings do not change; therefore, the ammonia tank costs remain the same.

4) The duct plenum and additional material costs would remain approximately the same. Although the portion of the duct from the SCR to the stack would be shared, more complex flow diverting and straightening ductwork would be required.

5) The engineering portion of the OAQPS calculations (from Table 2.5 of OAQPS Cost Manual, Section 4.2, Ch 2) has been doubled to account for the engineering rigor required to redesign a custom solution. This conservatively results in a $60,000 capital cost increase.

6) The life of the catalyst is affected due to the fact that they are guaranteed for certain hours of operation, whether a single or two turbines operate. The guaranteed life of the catalyst is assumed to be 2.7 years (17,500 hrs guarantee / (3200 hrs operation * 2 turbines)).

7) The power requirements do not change as the same energy will be required to operate tempering air fans and ammonia systems because the flowrate and pollutant loading does not change. The same assumption applies to increased natural gas fuel costs due to pressure loss because the same amount of catalyst would be required.

Based on these conservative assumptions, the cost per ton of control for the proposed system was calculated to be $11,376/ton. The analysis did not factored in any potential control efficiency loss due to uneven or insufficient heating of the catalysts. To counteract the varied range of heat transfer conditions that the catalyst would experience, the vendors might choose to increase catalyst surface area, adding capital costs and pressure loss, thereby increasing fuel costs as well. None of these potential costs were factored into this economic screening analysis.

Thus, a "two turbine, single control" option did not offer improved cost effectiveness over the cases analyzed in the application, despite over $366,000 of potential capital cost savings.

Comment: The proposed gas plant would be a significant source of environmental pollutants. DEQ states that adequate emissions controls cannot be justified economically – the public must be dependent on only proper operation of the proposed facility (using pipeline quality gas) to control emissions. Industrial facilities that are not operated properly should not be allowed to operate, and proper operation should never be a substitute for designing and constructing industrial facilities to operate with as little impact as possible. [Gessaman 9/30/09]

Response: The Department agrees that the proposed gas plant would constitute a significant source of certain air pollutants in the sense that the potential emissions of certain air pollutants from the facility would not be insignificant or immaterial, and the Department is required to evaluate those emissions and require compliance with applicable ambient standards and other air quality requirements. The Department also agrees that the facility would meet the definition of "major stationary source," within the meaning of the Prevention of Significant Deterioration (PSD) program requirements, and the Department has conducted the analyses required for an application subject to PSD. However, there is an important difference between air emission levels triggering analyses and air emissions having significant impacts on the environment, within the meaning of MEPA. Air pollutant emissions from the proposed project would not exceed any applicable air quality standards set to protect public health and welfare and the environment. In most cases, air pollutant emissions from the HGS would be well below applicable standards. The Department has determined that air pollutant emissions from the HGS would have minor impacts on the environment.

The facility must not only meet air quality standards, but must also apply the maximum emission control capability taking into account energy, the environment, and economics. The Department followed the required statutes to justify "proper design and operation, and use of pipeline quality natural gas," as control for pollutants PM, PM10, PM2.5, NOx, and SO2. ARM 17.8.752 (1) states, "The owner or operator of a new or modified facility emitting unit for which a Montana air quality permit is required by the subchapter shall install on the new or modified facility or emitting unit the maximum air pollution control capability that is technically practicable and economically feasible, except that: (a) BACT must be utilized…", where "BACT" is defined in ARM 17.8.740 (2) to be based on "…energy, environmental, and economic impacts and other costs…"

For those pollutants also subject to BACT under ARM 17.8.819, the BACT determination must also take into account, "energy impacts, environmental impacts (including, but not limited to, the effect of the control technology option on hazardous air pollutants), and economic impacts and other costs…" The selection of BACT for emissions controls is based on methodologies that consider how effective, available, proven, and cost-effective the technology is; these methods were followed in Section 5.0 of the permit application, and summarized in Section III of the permit analysis. Because the modeling demonstration indicated compliance with all ambient air quality standards, and because the Department followed the criteria for determining BACT, the Department's decision in terms of the BACT analysis and resulting permit conditions will remain as written.

CONSTRUCTION, COMMISSIONING, AND STARTUP/SHUTDOWN TOO FLEXIBLE

Comment: The commissioning period (not to exceed 16 weeks) provided for combined cycle operation is unreasonably long - 16 weeks is 4 months. In our considerable industrial experience, even the most complex plants are commissioned in a matter of a few weeks once construction is finished. How quickly an industrial facility is commissioned and operating at design conditions is frequently more a matter of owner/operator experience and commitment than facility complexity. The only reason we can see for allowing for a lengthy commissioning period is to permit the applicant to operate for an extended period of time without optimum emission controls. At the recent meeting (9-23-09), in Great Falls the public was told that Federal regulations allow up to 180 days of commissioning operation; there is no logical reason that Montana regulations cannot be much stricter than Federal regulations! [Gessaman 9/30/09]

Response: Commissioning by itself is a rarely occurring activity. During commissioning, rigorous testing is required to fine-tune operations and ensure various monitoring systems are operational and feedback systems perform as required. For purposes of emissions, limits must accommodate a period of constant change in a progression towards normal operation. The Department determined that BACT during this period would be a requirement to install and operate the air pollution control equipment prior to commissioning. This meets the requirement that the 'best available' control technologies are installed and operational during the period.

While Federal regulations allow 180 days of shakedown (including 40 CFR 60, Subpart A – General Provisions), the 16 week limit in MAQP #4429-00 is stricter than that which Federal regulations allow. Therefore, permit conditions will remain as written.

Comment: The proposed permit allows three years for construction of this gas-fired facility to begin before the permit expires (item H on page 7 of proposed permit). ARM 17.8.762 is cited as the reason for this allowance, but page 8 of the Permit Analysis quotes ARM 17.8.762 as stating, "12. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing **that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued."** [Emphasis added]. The revoked permit (#3423-01) for the HGS coal-fired plant allowed a maximum of 18 months. The coal-fired plant was a much larger and more complex undertaking with funding requirements about five times larger than this proposed plant. This gas-fired plant is a simple industrial facility with modest funding requirements and hence funding and construction should be able to occur quickly. A permit duration near the minimum (1 year) allowed by ARM 17.8.762 would be more appropriate – this is especially important given the high potential for meaningful CO_2 control legislation in the near future and the possibility that permitted but not yet constructed facilities might potentially receive some type of grandfathering. [Gessaman 9/30/09]

Response: ARM 17.8.762 states: "17.8.762 DURATION OF PERMIT (2) A permit issued prior to construction or installation of a new or modified facility or emitting unit may provide that the permit or a portion of the permit will expire unless construction or installation is commenced within the time specified in the permit, which may not be less than one year or more than three years after the permit is issued." The Department selected the three-year condition as allowed by statute. Because the condition is within the limits required by statute, the permit condition will remain as written. Note that the revoked permit #3423-01 for the coal plant allowed 18 months per the request of SME; the draft Permit #3423-00 included a three-year timeframe, which is and was consistent with the current rules and the rules at the time that permit was issued.

Comment: Commence construction on Phase I within 18 months and Phase II within 3 years. The commencement of construction deadline contained in Section III, H., should be adjusted to reflect the dynamic nature of emissions control technology. The commence of construction deadline should be 18 months in this age of global warming where new technologies are emerging and may be available to control greenhouse gas emissions in the near future. It is unreasonable to fail to require a shorter timeframe and require a BACT update after 18-months if the plant fails to begin construction. This plant will increase carbon dioxide emissions by 0.5 million tons per year. That is significant in any event and is roughly equivalent to the greenhouse gas emissions of every car in the Montana on an annual basis. DEQ should do what it can to ensure that the most up to date technology is used on a consistent basis. That can only be done by making more reasonable timeframes for commencing construction. According to the PD and SME's application, this permit allows construction of two different generating stations – a simple cycle facility and combined cycle facility. As such, there should be separate commencement of construction requirements for Phase I and Phase II of the project. SME should not be allowed to build Phase I and wait 5 years to build Phase II. If SME wants to phase in construction of these two different facilities, the final permit should require SME to commence construction on Phase I within 18 months and Phase II within 3 years. BACT requirements are designed to require installation of state-of-the-art pollution control technology. For that reason, air quality permits are limited in duration. To obtain an extension of the construction requirements in an air quality permit, a permittee is required to submit an updated BACT analysis that ensures that the permit's emissions limitations reflect "the maximum degree of reduction of each pollutant subject to regulation" under the federal Clean Air Act and the Clean Air Act of Montana. The laws on commencement of construction are clear. DEQ must establish a construction deadline for both Phase I and Phase II of this permit. [MEIC 9/30/09]

Response: ARM 17.8.762 states: "17.8.762 DURATION OF PERMIT (2) A permit issued prior to construction or installation of a new or modified facility or emitting unit may provide that the permit or a portion of the permit will expire unless construction or installation is commenced within the time specified in the permit, which may not be less than one year or more than three years after the permit is issued." The Department selected the three-year condition as allowed by statute. Although SME refers to the simple cycle and combined cycle operations as Phase I and Phase II, they are not "independent phases" as referenced in ARM 18.8.819 (and EPA PSD guidance on this topic), as both types of operation use the same turbines. Therefore, the Department disagrees that separate construction requirements for simple and combined cycle operations would be appropriate. In addition, Condition III.H of MAQP #4429-00 states, "Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762)." Commencement of construction would not be the only test to maintain all parts of the permit. Due diligence would also have to be demonstrated for both simple and combined cycle operations.

Comment: Relaxed emission limits are allowed for startup and shutdown periods. The time allowed for startup and shutdown (S&S) periods appear excessively long, especially in view of the fact that up to four S&S and two S&S are expected daily during simple cycle and complex cycle operation, respectively. Under the proposed regimes, emissions could be larger than necessary for up to one third and one quarter of simple cycle and complex cycle daily operation, respectively. With so many expected S&S periods daily, the startups would more than likely be "hot" operations that do not require as long for the facility to reach steady state operation as startup following a "cold" shutdown. The allowed extended startup and shutdown periods do not provide any incentive to operate the facility cleanly. [Gessaman 9/30/09]

Response: As discussed throughout Section 5.0 of the permit application, the extended startup and shutdown periods are included to accommodate the technical constraints of material properties. During combined cycle startup, the rate at which the turbine throttle can be increased is limited by the maximum allowable temperature and pressure ramp rates for the heat recovery steam generator (HRSG) high pressure steam drum. Throttle increases are managed to prevent HRSG heating in excess of 22°F/min until the drum operating pressure is reached. The average time to accomplish the combined cycle startup is approximately two hours following the introduction of fuel to the turbine. During this heating period of the HRSG steam drum, the minimum SCR operation temperature will be reached, and some NOx reduction will occur, with maximum steady-state control achieved at the end of the startup period.

The same basic logic applies during a combined cycle shutdown. The steam drum must be cooled at a controlled rate to avoid excessive thermal stresses. The turbine throttle will be managed to avoid cooling the steam drum too rapidly. During this time, until the SCR temperature falls below the minimum operating temperature, the ammonia injection grid will be active, and NOx reduction will occur. Once the temperature falls below the SCR minimum operating temperature, no NOx reduction will occur. Maximum control of combined cycle shutdown emissions is accomplished by cooling the steam drum at the maximum allowable temperature and pressure ramp rate. Emissions during combined cycle shutdown result from the combustion of fuel. Good combustion practice would indicate that fuel cutoff occur as soon as safely practicable, considering the HRSG vendor's maximum allowable temperature and pressure ramp rate. For this project, an average one-hour time period has been identified as the time period to accomplish the HRSG cooling that would require the turbine to remain operational. Once fuel is cut off, the HRSG could cool via convection from the turbine exhaust during spindown, although no emissions occur at this time because no fuel is being combusted.

Due to the rapid startup and shutdown times for simple cycle operation (minimum of ten minute startup, eight minute shutdown) any additional NOx controls will not reach operating temperature during that timeframe. Add-on control is effectively zero during such a rapid startup and shutdown. The DLN system will begin "to lean" the fuel combustion during both a simple cycle and combined cycle start after six minutes from hydraulic turbine spin-up. Therefore, the maximum control during rapid simple cycle startup/shutdown conditions is to reach baseload conditions as rapidly as practicable, to enable the DLN system to stabilize. As defined by the turbine vendor, the minimum safe startup period for simple cycle startup is defined as a ten minute startup and an eight minute shutdown.

As a practical enforcement matter, the emission limit during simple cycle operation is based on a 1-hr average for both simple cycle startup and shutdown, and startup/shutdown is limited to one hour each per condition II.A.5. As for combined cycle operation, permit condition II.A.7 assumes no more than two combined cycle startup/shutdown cycles per day, resulting in the annual hourly limits on startup and shutdown hours. Because of the technical constraints discussed above, the permit conditions will remain as written.

PERMIT LANGUAGE SHOULD BE REVISED

Comment: From Permit Page 3, Section II.9, SME requests a change to the language of the subject permit limitation in order to clarify that the reporting requirements and averaging times are in accordance with 40 CFR 60 Subpart KKKK. The request change is to add the phrase, "*…in accordance with the standards and limitations, and reporting, recordkeeping and notification requirements contained in 40 CFR 60 Subpart KKKK*. [SME 9/30/09]

Response: The Department has added the suggested phrase to condition II.9 to clarify that conditions are in accordance with 40 CFR 60 Subpart KKKK.

Comment: To clarify startup notification requirements for simple cycle and combined cycle operations, SME suggests permit condition II.E.2 be revised from "Actual startup date of each turbine generator within 15 working days after the actual startup of each turbine generator" to "*Actual startup date of each turbine generator* ***for each mode of operation (simple cycle and combined cycle)*** *within 15 working days after the actual startup of each turbine generator* ***for each mode of operation***" (emphasis added to show added text). [SME 9/30/09]

Response: The Department revised condition II.E.2 to clarify that SME must notify the Department for both simple cycle startup as well as combined cycle startup.

Comment: The permit omits Attachment 1 which is typically reserved for ambient monitoring requirements, and is not applicable to this project. SME requests that an "intentionally blank/reserved page" note be added to the permit in place of Attachment 1 to prevent confusion. [SME 9/30/09]

Response: Attachment 1 is normally reserved for ambient monitoring requirements. Because there are no such requirements at this time, the Department has added a page to clarify that Attachment 1 is intentionally left blank.

Comment: From Permit Page 15, Attachment 3, throughout, SME requests revised language throughout concerning the definition of the end of startup and the beginning of shutdown. Throughout the startup and shutdown period, the power set-point will vary as the turbine is accelerated and decelerated. The proper definition would be the "dispatched set-point" which is the turbine load value requested by the control center which initiated the startup or shutdown. This is an administrative/wording change only; the emissions inventory and BACT analyses were based on the dispatched set-point as the trigger for ending startup and initiating shutdown. The emissions, averaging periods and durations of startup and shutdown do not change with this requested language change. [SME 9/30/09]

Response: The Department has added the definition of "Dispatched Power Set-Point" to Attachment 3, and has revised the remaining Attachment 3 definitions to reference the term "dispatched set-point."

Comment: From Permit Page 15, Attachment 3, Combined Cycle Commissioning, SME requests that the definition be revised to accommodate a commissioning period during initial HRSG and catalyst install, and catalyst reinstallation in the future. As currently written, the combined cycle commissioning period would not apply during the initial HRSG and catalyst install as the turbine will already be in place because the simple cycle portion of the plant will have already been constructed. The suggested revision is as follows: "*The process that begins with the first episode of fuel combustion in a turbine undergoing combined cycle operation, following any time a new or refurbished turbine* ***or catalyst*** *is installed or re-installed at the facility. The commissioning period for an individual turbine shall not exceed 16 weeks following the first episode of fuel combustion in the* ~~***new or refurbished***~~ ***affected*** *turbine. The commissioning period applies to combined cycle operation only since there are no post-combustion controls to adjust for simple cycle operation*" (emphasis added to highlight change). [SME 9/30/09]

Response: The Department has revised the definition of "Combined Cycle Commissioning" to clarify that it includes periods of catalyst installation.

Comment: From Draft EA, page 67, Water Quality, Quantity and Distribution, SME requests revised language to provide clarification on the water needs during simple cycle and combined cycle operations. The reduction in raw water needs from 3,100 gpm to approximately 100 gpm will occur during simple cycle operation. During combined cycle operation, the typical water needs will be approximately 700 gpm. The applicant requests that the following language be substituted into page 67 of the Environmental Assessment to provide clarification on the water needs during simple cycle and combined cycle operations:

"SME's needs for raw water at the Project site have been reduced from approximately 3,100 gallons per minute to less than 100 gallons per minute during simple cycle operation. Water consumption may be approximately 700 gallons per minute when operating in combined cycle mode. The approximate water usage for the Project is summarized in the table below:" [SME 9/30/09]

Estimated Average Water Usage for the Highwood Generating Station Gas Plant

Operational Mode	Water Intake (GPM)	Cooling Towers Evaporation (GPM)	Misc. Water Use (GPM)	Water Discharge (GPM)
Simple Cycle	100	0	100	0
Combined Cycle	700	400	100	200

Response: The language in the EA has been modified to include the above language and table in order to clarify water use.

DEQ SHOULD CONSIDER ALTERNATIVES TO THE PROPOSED PROJECT

Comments:

- In the FEIS and in the ROD associated with the 2007 FEIS, SME contended that the Salem/NHL site was uniquely suited to SME's ability to build a coal plant based on ability to construct railroad lines and run coal trains to the facility without impacting the neighborhoods of Great Falls or crossing the river (FEIS, ES-7 to 8) and having adequate room for ash storage cells and the ability to accommodate four wind turbines. SME has withdrawn its air permit for the coal plant and has publicly stated that wind turbines are no longer part of their planned gas-fired power plant project. Thus the major factors that led in 2007 to the selection of the Salem site over the Alternative site are no longer relevant. Because siting a gas plant involves a different set of criteria, the siting analysis presented in the FEIS is not a valid basis for purposes of determining the preferred course of action for building a gas plant. EAs on the Montana DEQ website, except for documents meeting categorical exclusion requirements, typically include discussion of a range of options besides the proposed action. [MPA 9/30/09]

- Only one action alternative, construction and operation of a natural gas-fired plant at the Salem site is presented in the EA. DEQ equates a final decision on the application to issue a permit to be the "action alternative" and denial of a permit to be the "no action" alternative. DEQ interprets MEPA 75-1-201(5)(a) to limit its authority to consider alternatives to a proposed action as state d above. How does DEQ reconcile this interpretation with other MEPA provisions?; i.e., (1) the agency proposing the alternative shall consult with the project sponsor regarding any proposed alternative [MEPA 75-10-201 (1)(b)(iv)(C)(I)(II)]; (2) if the project sponsor believes that an alternative is not reasonable as provided in subsection (1)(b)(iv)(C)(I), the project sponsor

may request a review by the board, if any, of the agency's determination regarding the reasonableness of the alternative [MEPA75-10-201 (1)(b)(iv)(C)(I)(III)]; (3) in accordance with the criteria set forth in subsection (1)(b)(iv)(C), study, develop, and describe appropriate alternatives to recommend courses of actions in any proposal that involves unresolved conflicts concerning alternative uses of available resources [MEPA75-10-201 (1)(H)]. NPS urges the Department to reconsider this interpretation and consider an action alternative to the proposed HGS at the Salem site that could result in issuance of an air quality permit. The EA should inform the public and the decision–making authority (government agency or agencies) of the environmental impacts from a reasonable range of alternatives. If an alternative does not meet CAA standards, then it is not reasonable. Reasonable alternatives should include actions other than issuing or denying the requested permit. The Department should choose between alternatives that can meet CAA standards with consideration of their varying environmental impacts. Otherwise, why assess environmental impacts from the project outside the scope of the CAA, such as noise, water quality, historic properties and socioeconomics, if only CAA requirements can be considered in the Department's decision on the air application? If more than one alternative was considered that could meet CAA standards, then the Department could use information on other environmental impacts to guide a decision on which alternative to permit. By limiting the Department's authority regarding approval of any project that meets air quality standards without consideration of alternatives or other impacts, it is our opinion that the Department is effectively rendering MEPA provisions applicable to air applications meaningless. [NPS 9/30/09]

- The MEPA analysis should include evaluation of alternatives that would result in lower carbon dioxide (CO2) emissions. [MEIC 9/30/09]

- The type of electric generation facility proposed (coal and wind) played a big role in selecting the Salem site. [NPS 8/20/09]

- The Site Selection Study identified a site almost two miles south of the location of the proposed HGS plant as a potential site for the coal-fired plant, later called "Section 36 site" in the FEIS. The current location of the proposed gas plant at Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana was not mentioned in the Site Selection Study. Another site north of Malmstrom in this study is several miles from the Portage Route and was dropped from consideration due to potential visual impacts to the Lewis and Clark Visitor Center. The rationale for dismissal of this site north of Malmstrom, coupled with the subsequent selection of a site actually on the Portage Route taken by Lewis and Clark, demonstrates that critical factual matters regarding the NHL and the Trail were inadequately understood during site selection and development of the draft EIS. The NPS was not consulted at any point during site selection or development of the DEIS regarding the Trail or NHL. The Site Selection Study doesn't support locating a coal-fired power plant at the location of the proposed HGS gas plant. Even if the study had selected the current site for the coal plant, factors considered in determining where a coal-fired power plant might be most appropriately located will differ from factors considered for a natural gas plant. [NPS 9/30/09]

- NPS sent email to USACE detailing concerns about locating plant on/adjacent to NHL. Email notes that "Salem site" was renamed "Section 36 site" and was dropped because it could not be bought. Site Selection Study does not identify Sections 24 and 25 as potential site. The site selection study does not compare Salem site at Sec 24/25 to other alternative sites. [MEIC, NPCA, SC 6/8/09]

  Response: During the review and proposed issuance of Montana Air Quality Permit #4429-00, the Department did address the issue of "Alternatives Considered" in the Environmental Assessment (EA) as required by the Montana Environmental Policy Act (MEPA) and rules

adopted pursuant to MEPA. As stated in the Draft EA, MEPA rule ARM 17.4.609(3)(f) requires the Department to consider reasonable alternatives to a proposed action whenever alternatives are reasonably available and prudent to consider. Further, Section 75-1-201(5)(a), MCA, of MEPA, states that an agency may not withhold, deny, or condition a permit based on MEPA. The Department has met the requirements of MEPA and as stated in the EA, "The Department's authority regarding this application is contained in the Clean Air Act of Montana and the rules adopted pursuant to it. That authority is to approve SME's permit application if it meets the requirements of the Act and rules and to disapprove it if the Act or rules are not met. Consequently, the alternatives that are reasonably available to the Department and prudent to consider in this EA are the alternatives of denial of the permit, which is the "no action" alternative, and issuance of the permit. Because the Department has no authority to require siting of the HGS at an alternative location as long as air quality laws and rules would be met at the Salem site or to require SME to use alternative energy sources, no other alternative sites or energy resources are analyzed in this EA." The Department does not agree that disclosure of the impacts of constructing the proposed gas-fired plant at the Salem site is made meaningless by the lack of discussion of alternative locations or power generation processes. Disclosure of those impacts provides meaningful information to the Department, to other governmental policy makers, to the public, and to SME.

CANNOT REJECT INDUSTRIAL SITE

Comments:

- The FEIS found that building a coal plant and wind turbines at the Salem Site would have adverse and significant impacts on cultural resources. Impacts on cultural resources at the Industrial Park site did not suffer the same significant adverse impacts, but DEQ dismissed the Industrial Park due to increases in local rail/truck traffic, hauling fly ash, proximity to other industrial and residential sources, and lack of space for wind turbines. DEQ identified the Salem site as its environmentally preferred alternative but noted the Proposed Action would result in an adverse effect on the Great Falls Portage NHL that would be lessened under the Industrial Park alternative. The FEIS stated that the only significant, immitigable impact from building a coal plant would be caused by building the plant at the Salem site because of the impacts to the NHL. Because there will be no wind turbines and the permit for the coal plant has been revoked, and because SME is only proposing to build a natural gas plant, DEQ's previously stated reasons for rejecting the Industrial Park site are no longer valid. [MEIC 9/30/09]

- The EA selectively re-characterizes conclusions from the EIS. The conclusion reached in the EIS was not that a new fossil fuel power generation facility at the HGS site was the best alternative, but that a new coal-fired power generation facility was the best alternative; the Salem site was not chosen as ideal for any type of fossil fuel facility. The statement in the EA that states a number of noncombustible energy sources were rejected in the EIS is substantially incomplete. In the EIS, RUS and DEQ rejected consideration of a number of noncombustible energy resources and the combustible resource, natural gas. The EIS clearly dismissed natural gas generation as an alternative prior to conducting detailed environmental studies on the only type of generation technology put forward as a viable alternative: coal-fired generation. The only two action alternatives considered in the EIS were: 1) coal-fired plant with wind at the Industrial site, and 2) coal-fired plant with wind at the Salem site. The evaluation of both the Industrial Site and Salem Site was solely limited to consideration of building a coal-fired power plant at either site. [NPS 9/30/09]

Response: The Department was required to conduct an environmental review under the requirements of MEPA. The Department analyzed the impacts associated with the proposed construction and operation of a natural gas plant. As part of the natural gas plant analysis, the

Department also considered the revocation of the coal fired power plant and the withdrawal of the proposed wind turbines. The Department reviewed the siting analysis that was completed as part of the Final Environmental Impact Statement (FEIS) for SME and the proposal for which the action was being taken and determined, as stated in the Draft EA, that "Subsequent to completion of the alternative evaluation study, there have been significant changes in the regulatory and financial environments. The net result of these changes materially impacted the viability of proposed and existing coal-fired electric generation facilities. SME has stated that, based on this marked change in the external conditions impacting electric generation capacity development, SME now believes that natural gas-fired generation, complemented with competitively priced power purchase agreements, represents the most reasonable near term solution to the power supply needs of SME and the member systems it serves. Based on its desire for a higher level of power supply certainty, SME decided to develop the natural gas-fired generation facility."

The Department conducted an EA for the action that was under consideration, which was the proposal for SME to construct and operate a natural gas power plant, and at the same time SME no longer has the authorization to construct and operate a coal-fired power plant or wind turbines at the Salem site. Under such review the Department has determined that there are no significant impacts associated with the current project under this review and therefore an Environmental Impact Statement is not required**,** given that the MEPA rules require consideration only of alternatives that are reasonable and prudent to consider. The Department acknowledged in the EA that the zoning issue is currently in judicial proceedings. However, the Department does not have the authority to violate statutory timeframes for issuance of a Montana Air Quality Permit based on other judicial proceedings that may be occurring

EA DOES NOT ADDRESS NEW DATA AND/OR UNRESOLVED ISSUES

Comment: EA pg. 96 states, "RUS initiated and nearly completed a Section 106 consultation with interested parties, including the State Historic Preservation Office (SHPO), the National Park Service, the Advisory Council on Historic Preservation, and other local and national groups." This statement is incorrect. In March 2007, ACHP requested that the Secretary of the Interior prepare a Section 213 Report to evaluate the impacts of the proposed HGS on the Great Falls Portage. Such a request is very rare and clearly would not be requested if consultation was "nearly complete." When the ROD was issued in May 2007, RUS's obligations under NHPA had not been met and it is NPS's opinion that to do so would take considerable effort and time. The future permitting needs and need for further consultation per NHPA should be disclosed to the public in the EA. There should be discussion in the EA of the potential historical and archaeological impacts of siting a new natural gas pipeline under the Missouri River and through the NHL. [NPS 9/30/09]

Response: The Department has revised the final EA to make it clear that the Section 106 process was not previously completed by SME. The Department discussed the construction of the natural gas pipeline, as well as the additional permits and authorizations that may be required for the construction and operation of its component parts. The Department references the Section 213 report prepared by the Department of the Interior for the construction and operation of a coal-fired power plant and associated wind turbines.

The US Army Corps of Engineers has withdrawn its request for Section 106 consultation in a letter to the Advisory Council on Historic Preservation (dated September 22, 2009, with a copy received by the Department on September 28, 2009). In the letter, the Corp states that it received a request to withdraw SME's existing permit request for the coal-fired facility, and in a letter dated September 10, 2009, the Corps withdrew SME's original application that had been submitted April 16, 2008. The Corps' September 2009 letter continues, stating that

SME has submitted a new application on September 3, 2009, for a natural gas-fired combined cycle generating facility, and "Under this revised proposal, the only activity regulated by the Corps will be an aerial crossing of the Missouri River by a redundant 230 KV electric transmission line," which will cross the river approximately 7 miles west of the boundary of the Lewis & Clark Great Falls Portage National Historic Landmark. The letter concludes, "Our evaluation of the new permit application led to a determination that the Corps lacks sufficient Federal control or responsibility under Section 10 to expand its analysis to include activities undertaken outside waters of the United States," and "Consequently, the Corps analyses under NEPA and NHPA will address only the revised project's construction of the 230kv aerial transmission lines across the Missouri River and the towers immediately supporting the transmission line crossing."

Northwestern Energy would determine the precise location for the natural gas pipeline, and Northwestern would construct the pipeline. Northwestern would be required to obtain all necessary state and/or federal permits, and environmental analysis would be conducted pursuant to MEPA, and NEPA if it applies, at that time. Because actual siting of the gas pipeline is undefined at this time, and because permits for the pipeline have not been sought, descriptions of potential impacts to historical and archaeological resources, and other resources, in the gas plant EA would be generic and speculative. However, in an attempt to address potential pipeline impacts, the Department has added language to pertinent EA sections to acknowledge that there would be potential impacts.

AN EIS/SEIS IS REQUIRED

Comments:

- MEPA requires DEQ to conduct an environmental review whenever a proposed State action could have an impact on the human environment. According to one source an EIS is necessary: "If it is unclear whether the proposed action may generate impacts that are significant, then an agency may prepare an EA in order to determine the potential significance (MEPA Model Rule III (3)). If the EA determines that the proposed action will have significant impacts, then either an EIS must be prepared or the effects of the proposed action must be mitigated below the level of significance and documented in a mitigated EA (MEPA Model Rule III(4))." (A Guide to the Montana Environmental Policy Act, Legislative Environmental Policy Office, Updated 2009.) In this case, an EA is inappropriate because DEQ already concluded that an industrial facility at the Salem site would have a significant adverse impact to the NHL that could not be mitigated. The NPS conducted a rarely conducted study under the National Historic Preservation Act §213. The §213 report concluded that the impacts to the NHL from the HGS would be significant and adverse. DEQ post-hoc rationalization that these affects are no longer significant is not based on evidence in the record and violates MEPA. DEQ must conduct an EIS under MEPA that includes analysis of an alternative to avoid the significant adverse impact to the NHL. That must include consideration of an alternative site such as the Industrial Park. [MEIC 9/30/09]

- EA based on coal plant 2007 FEIS that did not offer analysis for a gas fired plant; instead rejected such a facility and declared that only a coal plant would meet needs. Thus this EA, predicated on that FEIS, is wholly deficient for the purposes of now analyzing the SME's application for a permit for a gas plant on Salem Road. DEQ must prepare an SEIS that would more fully and honestly explore need, impacts, alternatives. [MPA 9/30/09]

- An EIS should have been done for the gas plant. The coal plant FEIS was done several years ago specifically for a coal plant and excluded the possibility of a gas plant satisfying need for power. The location of the plant is based on site selection information in an outdated EIS for a revoked permit. Nearly all the rationales and justifications given for selection of this site are no longer valid. In addition, the industrial zoning of the site is currently contested before the Montana Supreme Court by nearly all the landowners of the surrounding property. [Gessaman l 9/30/09]

Response: The Department has an obligation to meet the requirements of MEPA for each action that is not exempt from MEPA. The Department conducted an EA for the action that was under consideration, which was the proposal for SME to construct and operate a natural gas power plant. For the EA, the Department considered the fact that SME no longer has the authorization to construct and operate a coal-fired power plant or wind turbines at the Salem site. After completing the review, the Department determined that the project would result in no significant impacts; therefore, an Environmental Impact Statement is not required for this action.

Comments:

- In 2002, DEQ required an EIS prior to issuing air quality permits for the Silver Bow Generation Project, which included the construction of gas-fired turbines and related pipelines. Many of the same environmental impacts generated by the Silver Bow project are present with the current SME proposal. Yet now in 2009, DEQ proposes to issue a permit without requiring an EIS for a project acknowledged to have major, unmitigable effects on the Great Portage National Historic Landmark, a cultural resource of national significance. [MPA 9/30/09]

- We continue to believe that viable alternatives definitely exist that make it completely possible to provide all the electricity needed to meet the needs of Great Falls and SME's rural cooperative members, without destroying the Great Falls Portage NHL. We urge that DEQ require an SEIS that would allow for these possibilities to be given fair consideration. [MPA 9/30/09]

- NPS strongly disagrees with the EA conclusion that the gas plant would not have any significant environmental impacts, or that an EIS or SEIS is not required. As NPS stated in our August 19, 2009, letter, the NPS would continue to expect impacts on the NHL from constructing HGS at the Salem site which are too significant to mitigate with a proposal to build the gas plant only. The appropriate level of review under MEPA and NEPA for this action is an SEIS. [NPS 9/30/09]

- The original EIS did not examine the negative impact on the environment resulting from operation of a natural gas-fired electrical generating station. [Dolman 9/30/09]

  Response: The Silver Bow Generation Project was a substantially larger project. It was proposed to be a combined cycle facility generating 500 MW of electricity. The main gas line was to be expanded by looping 80 miles of 20" pipeline in three segments starting near Choteau, MT, and 17 miles of 16" pipe was to be installed to link the plant with the main gas line. The compression of gas along the gas line would have also needed expansion along with several other Departmental permit actions for the proposed project. The impacts of the Silver Bow Project were assessed accordingly.

  The Department does not agree that the proposed project would have major impacts on the NHL. As demonstrated in the EA, the proposed project would have adverse impacts on the NHL, including adverse impacts to the visual, acoustic, and cultural and historical values of the NHL. For purposes of MEPA, impacts can be ranked as significant or non-significant or they can be ranked with greater precision as minor, moderate, or major, with major equating to significant. In the EA for this project, in order to provide more precise information to the public, the Department has chosen to rank impacts as minor, moderate, or major. The Department could have ranked the impacts of the project on the NHL as non-significant, however, the Department believes that, for purposes of this project and its impacts on the NHL, it is more accurate to describe impacts on the NHL as moderate, due to the cultural and historical significance of this resource. Due to the much lower stack heights for the project, as compared to the 400-foot stack proposed for the coal-fired plant, elimination of the four wind turbines previously proposed to be located within the NHL, and the fact that the project

would not be visible from the Staging Area Interpretive Site, the Department concluded that the impacts of the project on the NHL would be moderate at most and would not be significant or major, within the meaning of MEPA.

Section 75-1-201(1)(b)(iv), MCA, of MEPA requires preparation of an EIS when a major action of state government would significantly affect the quality of the human environment. MEPA rule ARM 17.4.621(1) requires the Department to prepare a supplemental EIS (SEIS) whenever: (a) the agency or applicant makes a substantial change in a proposed action; (b) there are significant new circumstances discovered prior to the agency's final decision; or following preparation of a draft EIS and prior to completion of a final EIS, the agency determines that there is a need for substantial, additional information to evaluate the impacts of the proposed action or reasonable alternativ**es**.

If the current proposed action is viewed as a new proposed action, an EIS is not necessary because the action would not have significant impacts, as demonstrated in the EA. MEPA rule ARM 17.4.608(1) provides the criteria for determining the significance of each impact on the quality of the environment. These criteria include the severity of the impact, the quality of the environmental resource, the importance of the resource, potential conflict with local, state, or federal laws, requirements, or formal plans, and other factors specified in the rule. After considering these criteria, the Department concluded that none of the impacts of the HGS, including the impacts to the HGS, would be significant, within the meaning of MEPA. While the NHL is highly important, and industrial activity within, and adjacent to, the NHL that has adverse impacts on the NHL conflicts with NHL designation, the impacts of the HGS gas plant on the NHL would not be severe due to the specific impacts of the proposed project and the existing quality of the NHL.

The NHL consists entirely, or almost entirely, of privately owned land. While MEPA applies to private land as well as public land, most of the NHL is posted against trespassing, and the public does not have access, except for the small Staging Area Interpretive Site, in the northern portion of the NHL. The structures of the HGS gas plant would not be visible from the Staging Area, and it is unlikely that noise from the plant could be heard from that distance. The predominant use is agricultural, and most of the NHL is cultivated. Transmission lines currently cross the NHL, roads and several houses are visible from the NHL, and the Salem Road runs through a portion of the NHL. The visual and acoustic resources of the NHL already are adversely affected by the existing development in the area, and, although the HGS would be more visible and its noise more perceptible to persons who work or live within the NHL than to persons at the Staging Area Interpretive Site, the importance of the visual and acoustic resource within these developed private agricultural and residential areas to the state or society cannot be valued as highly as the importance of these resources in an undeveloped condition. Also, the Staging Area Interpretive Site is even more developed than most of the surrounding area. The Interpretive Site is accessed by a road, is surrounded by a fence, and contains benches and signs, and electrical transmission lines, a fuel line, another road in the distance, and houses are clearly visible from the Site.

The Department agrees that air emissions from the gas plant would be different than the air emissions from the previously proposed coal plant evaluated in the EIS for that project, and, as with any new source of air pollution, including industrial sources, agricultural sources, residential sources, and sources such as motor vehicles, would add to existing concentrations of air pollutants now found within the NHL. Air pollutant emissions from the proposed HGS gas plant have been evaluated in the EA as well as in the Permit Analysis for the air quality permit. As discussed in the EA and Permit Analysis, evaluation of the air quality impacts of the gas plant, including computer dispersion modeling, has demonstrated that air pollutant emissions from the proposed gas plant generally would be much less than those of the previously proposed coal plant and would not violate any air quality standards.

If the current proposed action is viewed as a change to the previously proposed coal-fired power plant, for which the Department completed an EIS, subsections (b) and (c) of ARM 17.4.621(1) would not apply because the Department already made a final decision concerning the air quality permit for the coal-fired plant, and the Department completed the EIS for that project. Subsection (a) does not apply because the currently proposed natural gas-fired plant would not constitute a "substantial change" to the proposed coal-fired plant, within the meaning of MEPA. The gas-fired plant would not have any significant impacts. The cultural, visual, and acoustic impacts to the NHL found to be significant for the coal-fired plant by RUS and the Department in the coal-fired plant EIS would not be significant for the gas-fired plant due to the significantly lower stacks and lower noise levels and the existing development on and around the NHL. Also, although the Department does not believe the impacts of the gas-fired plant would be significant, even if they would be significant, in the completed EIS for the coal-fired plant, the Department already analyzed the cultural, visual, and acoustic impacts of a power plant at the Salem site, none of the cultural, visual, or acoustic impacts of the gas-fired plant would be greater than the impacts to those resources by the coal-fired plant, and the environmental impacts of the gas-fired plant would be less than the environmental impacts of the coal-fired plant.

For this project, the Department determined that the degree and intensity of the impacts were not significant and that an EA was the appropriate level of analysis. The Department did not receive any comments that would justify changing that conclusion. Therefore, the Department has proceeded with the issuance of a final EA.

Comment: The Department has a responsibility to prepare a Supplemental EIS rather than relying on a flawed document prepared by the proponents.

Response: SME submitted a preliminary Draft EA with its permit application, and the Department used much of the information from that document in its Draft EA. However, several Department staff members spent considerable time reviewing the EA information provided by SME, Department staff requested and received additional information from SME, Department staff traveled to the site of the proposed HGS and viewed that site as well as the NHL, including the Staging Area Interpretive Site, and several Department staff members made significant revisions and additions to the EA provided by SME. The Department based its EA on the best information available to it, and the Department does not believe that its EA is flawed.

INSUFFICIENT PURPOSE AND NEED ANALYSIS,

Comment: The EA states that coal plant plans have been abandoned, and that the gas plant and power purchase agreements are the near term solution. Will the gas plant meet both near and long term supply needs? The NPS is concerned that additional generation facilities will be constructed at the HGS site in the future to meet SME's generation needs, which were projected in the EIS to be 250 MW. The gas plant is sized to produce 120 MW. [NPS 9/30/09]

Response: The Department does not have the authority to deny the application for a MAQP based on the supply needs. The obligation under MEPA requires the Department to disclose the purpose of the proposed project. If SME later chose to pursue a coal-fired power plant, they would be required to meet the requirements of the Montana Clean Air Act for that project and any other requirements of law for such an action. The ramifications of MEPA would be considered for that project at that time.

Comments:

- The Yellowstone Valley Electric Cooperative commissioned a study that concluded that power from the proposed gas-fired plant would cost 2.5 times more than YVEC's current power. [MPA 9/30/09]

- Regarding gas-plants, the FEIS concluded that "Price volatility and the likelihood of significantly higher future costs as a result of rising demand and limited supplies." This is in direct opposition to recent statements made by SME which described the natural gas-fired facility as "an effort to provide a predictable source of affordable electricity for its customers." [MPA 9/30/09]

- The condensed explanation in the EA of studies conducted exploring options for replacing SME electric generation sources when existing power purchase agreements expire fails to mention that these studies found construction of a natural gas plant infeasible. Rather, there is only mention that changing conditions made construction of a coal-fired plant more difficult. The inability to implement the original preferred alternative does not mean that any other alternative is now feasible by default. A new study should be undertaken to determine whether or not a natural gas plant is now feasible. [NPS 9/30/09]

  Response: In the case of this application, the Department is obligated to ensure that the facility can meet the requirements of the Montana Clean Air Act and to implement MEPA. Under the MEPA obligation, the Department is required to take into account all available information at the time of the analysis. The Department has met its MEPA obligation by conducting a review of all past actions related to the current project, as well as the current information for the proposal. Please refer to response to comments and responses the siting of the facility and the alternatives considered.

  The Department agrees that, in the EIS for the coal-fired plant proposed by SME in November 2005, the Department and the U.S. Rural Utilities Service (RUS) concluded that natural gas combustion would not be a reliable, cost-effective option for SME due to highly variable and volatile natural gas fuel costs and the likelihood of significant future price increases. At the time that SME proposed the coal plant, numerous coal-fired power plants were being proposed and developed around the country, and the relatively high price of natural gas and the lower availability of natural gas appeared to make coal combustion a more viable option. The Draft EA updated the information provided in the EIS by noting on page 62 that, since publication of the EIS, it has become more difficult to construct a coal-fired plant and that a gas-fired plant costs substantially less to build, takes less time to construct, and is easier to finance.

  The Department has not received the YVEC study referenced in the comment. In the EIS, the Department and RUS analyzed the feasibility of various alternatives to the proposed coal-fired plant because the proposal at that time involved an application for RUS funding. However, MEPA does not require an evaluation of the need for, or feasibility of, a proposed project. While NEPA regulations require analysis of the purpose and need for a project, MEPA rules require that an EA or EIS include analysis of the "purpose and benefits" of a project. ARM 17.4.609(3)(b) and 617(1). The EA for the HGS gas plant includes a discussion of the purpose and benefits of the project.

Comment: The description in the EA of current and future plans for HGS transmission lines to export electricity to users is inadequate. Since the capacity of the plant for electric generation is known, the need for transmission lines to relay this capacity should be determined now, not later. Or is there a reasonably foreseeable potential for generation expansion beyond the 120 MW? The Department should not accept this project application as complete without critical pieces of

information on transmission lines and pipelines. Without this information, the environmental impacts of the project remain unknown. The pipeline and transmission lines crossing a major water body create heightened concerns for environmental impacts that are not being addressed by the Department. Until the pipeline and power line permits are obtained and consultation on them completed, it would seem presumptive to complete the EA and issue the air permit. [NPS 9/30/09]

Response: The Department has disclosed in the draft and final EA SME's intention for electric transmission, natural gas consumption, the need for construction of a pipeline, and the use of alluvial wells for water. The Department also assessed and disclosed in the EA the environmental impacts related to each of these activities. The US Army Corps of Engineers has withdrawn its request for Section 106 consultation in a letter to the Advisory Council on Historic Preservation (dated September 22, 2009, with copy received by the Department on September 28, 2009). In the letter, the Corp states that it received a request to withdraw SME's existing permit request for the coal-fired facility, and in a letter dated September 10, 2009, the Corps withdrew SME's original application that had been submitted April 16, 2008. The Corps' September 2009 letter continues, stating that SME has submitted a new application on September 3, 2009, for a natural gas-fired combined cycle generating facility, and "Under this revised proposal, the only activity regulated by the Corps will be an aerial crossing of the Missouri River by a redundant 230 KV electric transmission line," which will cross the river approximately 7 miles west of the boundary of the Lewis & Clark Great Falls Portage National Historic Landmark. The letter concludes, "Our evaluation of the new permit application led to a determination that the Corps lacks sufficient Federal control or responsibility under Section 10 to expand its analysis to include activities undertaken outside waters of the United States," and "Consequently, the Corps analyses under NEPA and NHPA will address only the revised project's construction of the 230kv aerial transmission lines across the Missouri River and the towers immediately supporting the transmission line crossing." Furthermore, the Department disclosed in the EA a discussion of other potential authorizations applicable to the SME project. The Department does not have the authority to violate statutory timeframes for issuance of a Montana Air Quality Permit and its associated EA due to other permitting or proceedings that may be occurring.

INSUFFICIENT VISUAL ANALYSIS

Comments:

- Original EIS was for a coal plant; did not examine the negative impacts due to gas plant. Gas plant will have negative impacts due to visible structure, such as the smoke stack, and also noise pollution; the latter much more intense than coal fired facility. In addition, the air particles create a different impact. Opposed to the issuance of the air permit of the HGS on its current site. HGS should be located north of Great Falls where it makes no impact upon the National Historic Landmark. [Dolman 9/30/09]

- NPS thinks the BLM Visual Resource Management System (VRM) was not correctly applied in evaluating visual impacts to lands administered by the National Park Service. Due to the different missions of the NPS and BLM, the degree of disruption tolerated in the visual resources administered by each agency differs substantially. The mission of the NPS is to preserve resources for enjoyment by current and future generations. The BLM is charged with making the best use of Federal lands in meeting a broad range of commercial and recreational interests. NPS should have been consulted on an appropriate methodology to use in assessing visual impacts on NPS assets. A lot of useful, pertinent information regarding NPS's assessment of potential visual impacts from constructing HGS at the Salem site is available in the Section 213 Report. We provided the Department a copy of this report with the comments we submitted on the HGS

application on June 11, 2009. A Class III ranking is inappropriate for an area designated by Congress as both a National Historic Trail and an NHL. The BLM Visual Resource Management System guidance was not followed correctly. Using this guidance, a site partially within an NHL and along a National Historic Trail would be a Class I area. [NPS 9/30/09]

- The EA describes how the view from the Staging Area Interpretive Site is much changed from the view at the time of the Lewis and Clark Expedition. According to this visual assessment from the interpretive staging area, one would believe that the NHL has already been destroyed by the existence of agricultural features and even the features of the staging area itself. The NPS does not expect that all areas designated as NHLs will remain completely unaltered from historic conditions. However, these current uses on this historic landscape are not even comparable to the proposed industrial uses. Half of the photo in Figure 5 is the gravel surface of the parking lot and the remainder is the sky on a hazy day. The NPS does not think this photo is representative of what a visitor to the site would see. While visual analyses are rather subjective, one must try to focus on how the area is likely to be used and viewed. [NPS 9/30/09]

- The NPS disagrees with the DEQ's changed determination that the addition of HGS will have only a moderate visual impact. Rather than using existing man-made alterations as a reason to add more, consideration should be given to cumulative impacts and avoidance of adding additional impacts that together significantly affect the resource. [NPS 9/30/09]

- The visual assessment in the EA places considerable emphasis on which portions of the NHL are accessible to the public at this time. When considering impacts to NHL visual resources, the viewshed from anywhere within NHL boundaries must be considered, regardless of current ownership status. Lands that are currently in private ownership and marked with no trespass signing, may become open to public access, or even public ownership in the future and should not be deemed less important for visual resources or overall protection. [NPS 9/30/09]

- Insufficient information is provided for reviewers to determine if the additional 5 km radius viewshed analysis is valid. There are numerous computer-based models used to simulate viewsheds, but some researchers have found that most combinations of data, models, and visibility criteria only predict actual viewsheds with about 50 percent accuracy (Maloy and Dean, 2001. Photogrammetric Engineering and Remote Sensing, 67:1, 1293-1298). [NPS 9/30/09]

- It should be noted in the EA that moving the HGS plant a few hundred feet did not adequately address concerns from historic preservation parties because doing so did not reduce the visual and audible impacts on the NHL below significant levels and the adverse impacts remained immitigable at the new location. [NPS 9/30/09]

- Tacit agreements regarding mitigation between SME and RUS were not agreed to by the NPS at any stage of Section 106 Consultation or EIS review. The NPS still maintains that visual impacts to the NHL and the Trail from constructing HGS at the Salem site will be significantly adverse and not mitigable to a less than significant level. Mitigation for these significant impacts is required and should be agreed upon by NPS. The landscaping plans approved by Cascade County to mitigate visual impacts of the project were never approved by NPS to mitigate impacts to the NHL. Shifting the footprint of the plant off the NHL to a site still partially on and astride the NHL is not a mitigation measure. This "minimization measure" at best is ineffective since the chosen location the plant was moved to is still partially on and adjacent to the NHL and fully within the viewshed of the NHL. [NPS 9/30/09]

  Response: The Department assessed the visual impacts of the proposed construction and operation of the natural gas-fired power plant. The Department concluded in the EA that, "The gas plant's footprint and profile would be much smaller than those of the previously

proposed coal-fired plant. The tallest structure at the previously proposed coal-fired plant would have been the 400-foot CFB boiler stack. SME no longer intends to construct the previously proposed four wind turbines within the NHL, which will significantly reduce the visual impacts of the Project in the area and, specifically, will significantly reduce the visual impacts of the Project on the NHL." The Department concurs that the Section 113 report was issued**,** based on the previously proposed coal-fired plant; however, the purpose of the environmental review for the current project is not to analyze the coal-fired power plant impacts, but instead the purpose is to focus on the impacts associated with the proposal to construct and operate a natural gas-fired power plant.

The Department was, however, able to use some of the data previously reviewed for the coal-fired power plant proposal as part of the analysis of the impacts from the current natural gas-fired power plant proposal. Through its analysis, the Department determined that the visual impacts of the current proposal were not significant. The Department assessed the cumulative impacts of the proposal, but also recognized the current surroundings of the proposed natural gas-fired power plant location and the current uses of that land. The Department agrees that the photo in the EA of the view from the Staging Area Interpretive Site is not representative of every view from that site, and it does not show the Highwood Mountains or much of the NHL. The purpose of the photo was to depict the view from the Interpretive Site toward the site of the proposed project, since that view has been of concern. The photo also doesn't show the other fences, adjacent cultivated fields, roads, utility lines, and houses that are visible from the site. The point of the portion of the EA that addresses impacts to the NHL is to fairly and accurately evaluate the impacts of the proposed project, including the impacts to the existing environment, which included the development to date in the area.

The Department does not believe, and did not state in the Draft EA, that the NHL has been destroyed by existing development, however, the level of the existing development is a factor in evaluating the impacts of the present proposal on the existing environment. The Department agrees that the viewshed from anywhere within the privately owned NHL must be considered, and the Department did that. However, the view that has been of most concern to interested persons has been the view from the Staging Area Interpretive Site, because it is the only point of public access to the area, other than Salem Road. The Department is not aware of any changes in the foreseeable future to the access capabilities for the general public.

Also, the Department has found no supporting information that suggests that any mitigation measures previously proposed by SME were agreed to by the National Park Service. Again, the Department emphasizes that the analysis of visual impacts is based on the proposed facility, without speculation as to what additional projects may be proposed in the future. Regarding the validity of the viewshed analysis referenced in Comment 23, the Department did not receive any requests for information substantiating that analysis at any time subsequent to the availability of the analysis, which was included in SME's document *Response to May 20, 2009, Department Request*, submitted June 11, 2009 (Attachment 1 comments, Comment #52, pgs. 31-33). SME's responses, including the viewshed analysis, were mailed to NPS and other FLMS on 6/12/09, and posted to the DEQ website on 6/15/09 with email notification to NPS/FLMS that same day. The Department did not receive any additional viewshed analyses from other parties to contrast the results provided in SME's Responses to Comments.

The Department also agrees that it is important that an environmental analysis address cumulative impacts and that the proposed project will add to the existing impacts to the NHL. The Department noted on page 98 of the Draft EA that: "Air quality emissions from the Project would add to background air pollutant concentrations. Acoustic and visual impacts of

the Project would add to the acoustic and visual impacts of the existing development in the vicinity of the Project and would add to the existing impacts on the historical resource of the NHL."

INSUFFICIENT NOISE ANALYSIS

Comment: NPS disagrees with the DEQ's changed determination that the project's impact on the acoustic resource of the NHL will be moderate at most. We agree with the original assessment of significant impact that acknowledges the high standards to which NPS administers NHLs. Lacking in this assessment is consideration of cumulative auditory impacts from additional industrial facilities that are likely to develop around HGS after it is built. In addition, assessments of impacts to NHL resources should not be limited to only those areas that are currently accessible to the public. [NPS 9/30/09]

Response: The Department understands that the NPS disagrees with the conclusion of no significant impact to the acoustic environment. The Department is not aware of any additional industrial development in the area of the proposed HGS site, and any projection of future industrial development at the site would be speculative, especially in view of its rural location. If additional industrial development requiring permits from the Department were to occur in the area, the Department would complete its applicable MEPA obligations as required by MEPA for the project(s) at that time. As discussed above, the Department did not limit its assessment of impacts to the NHL to only those areas that currently are accessible to the public. The study of acoustic impacts included the areas of the NHL that are not accessible to the public.

PROJECT WILL IMPACT NHL AND/OR BE CUMULATIVE

Comments:

- The gas plant will have a significant impact on the integrity of the Lewis and Clark NHL, especially if it opens the door to the possible future construction of a coal-fired power plant. SME continues to publicly proclaim that it still plans to later construct a coal-fired plant at the Salem site. [Gessaman 9/30/09]

- Natural gas is a better source of generation, but such generation would be more economical and of higher efficiency in an existing industrial park, not aside a national landmark. [Liebert 9/30/09]

- With regard to a no-action alternative, the EA's "Cultural Resources" discussion states that "The no-action alternative would not affect this resource (p. 39 - the resource referred to is the Great Falls Portage NHL). It is incorrect to say that the No-Action alternative would not affect this resource, when No Action would mean the preservation of the NHL. As described in the Section 213 report issued by the National Park Service, HGS presents a major, unmitigable impact to the Great Falls NHL. [MPA 9/30/09]

- The Table on page 64 of the EA shows that the Department considers the project's impacts on historical and archaeological sites to be "moderate." The NPS strongly disagrees that the magnitude of impact upon the NHL would be moderate. The difference in opinion likely stems from the Department's characterization of the NHL as already significantly altered from the time of Lewis and Clark due to the rural farming landscape and other man-made structures on the NHL. [NPS 9/30/09]

Response: The Department's analysis included a review of the impacts on the National Historical Landmark as part of the environmental analysis. The Department determined that there would be no significant impacts to the NHL from the construction and operation of the natural gas-fired power plant. Please refer to the responses to comments alternative siting regarding the Department's lack of authority to change the proposed location for such a proposed facility and to responses to comments regarding on impacts to the NHL. The Department has no information from SME that would document that SME still intends to construct a coal-fired plant at the Salem site.

The Department disagrees that it incorrectly characterized the effect of the no action alternative on the NHL, and the Department disagrees that the no action alternative would mean preservation of the NHL. Implementation of the no action alternative would not preserve the NHL from future further development; it merely would mean that there would be no impacts from this proposed project, which is what the Department stated in the Draft EA.

The Department's determination that impacts to the historical and archeological sites would be moderate was not based solely on the Department's characterization of the NHL as already significantly altered from the time Lewis and Clark. The determination also was based on the much lower impacts of the proposed gas-fired plant, compared to the previously proposed coal-fired power plant, including the larger footprint of the coal-fired plant, the much more visible 400-foot stack that would have been part of the coal-fired plant, and the four wind turbines that would have been located within the NHL.

Comment: The proposed project may result in de-listing of the NHL. [NPS]

Response: The Department has previously received comments from the NPS, including a report of the Secretary of the Interior pursuant to Section 213 of the National Historic Preservation Act, prepared in response to SME's previous proposal to construct a coal-fired plant, indicating that de-listing of the NHL could occur and the Department has added this to the final EA. However, the report was prepared based on the previous proposal to construct a coal-fired plant, and, as discussed above, the Department has no authority to deny an air quality permit for the project based on the potential for the plant to affect NHL status for the Lewis and Clark portage area**.**

EA LACKS *SUFFICIENT* GAS AND TRANSMISSION LINE INFORMATION

Comments:

- The EA contains no discussion of essential infrastructure associated with the gas plant, such as pipelines. Gas pipeline construction will require environmental review and permitting and this is a major omission in the EA. The YVEC cost study evaluates the issues involved with gas line construction and permitting (see p. 10-11 at the link provided above). [MPA 9/30/09]

- NPS received a letter from the USACE dated September 22, 2009 stating that under SME's revised proposal, the aerial crossing of the Missouri River by a redundant 230 KV electric transmission is regulated by the Corps under Section 10 of the Rivers and Harbors Act of 1899. It should be made clear in the EA that a permit from USACE will be necessary to construct both the transmission lines and a natural gas pipeline under the Missouri River. [NPS 9/30/09]

- The natural gas pipeline cannot be relegated to Northwestern Energy as a separate action. The HGS gas plant cannot operate without a fuel source. It is a connected action. It is stated in the EA that HGS will combust only pipeline quality natural gas. Building a new pipeline under the Missouri River will require numerous permits and environmental reviews. Several Federal

permits or licenses would most certainly be required from agencies such as the Corps and Federal Energy Regulatory Commission. This Federal involvement in the HGS project affecting a NHL requires Section 106 consultation be completed prior to the start of construction. The NPS continues to request that an air quality permit not be issued to SME prior to completion of Section 106 consultation. The Advisory Council on Historic Preservation is clear that the Area of Potential Effect for a project includes the facility, not just the permit area. [NPS 9/30/09]

Response: The Department agrees that the impacts associated with the necessary natural gas pipeline for the project need to be disclosed. The Department was provided with limited information about the pipeline when the Draft EA was issued. For the Final EA, specifics about the gas pipeline remain uncertain. However, the Department has added language to the Final EA, in relevant sections, to acknowledge that impacts would result from pipeline installation**.**

The Department has also disclosed in the EA the fact that the actual construction and operation of the pipeline will be by NorthWestern Energy, not SME. NorthWestern Energy would also have to meet the applicable requirements of law in the siting and construction of the pipeline. A second electrical transmission line would not be essential to the proposed gas-fired plant, but would be constructed by Northwestern Energy Construction only if found by Northwestern to be necessary to stabilize its transmission system. Neither any additional electrical transmission line nor the natural gas pipeline would involve permits issued by the Department. In addition to any necessary federal permit(s), which would trigger environmental review pursuant to NEPA, in order to install a pipeline under the Missouri River, Northwestern would be required to apply for a permit from the Montana Department of Natural Resources and Conservation, which would trigger the requirement for environmental review pursuant to MEPA.

In a letter dated September 22, 2009, the Department received information from the Army Corp of Engineers stating that the only activity regulated by the Corps will be an aerial crossing of the Missouri River by a redundant 230 KW electric transmission line, located approximately 7 miles west of the NHL boundary. The Department's understanding is that neither DNRC nor the ACE has an application from SME at this time to install a natural gas pipeline across the Missouri River. The Department does not have the authority to violate statutory timeframes for issuance of a Montana Air Quality Permit and its associated EA due to other permitting or proceedings that may be occurring or that may occur in the future.

CONFUSION OVER APPLICANT, DEVELOPER

Comments:

- Confusion over permit applicant, who will construct and operate the plant, and who will be responsible for meeting permit conditions. "Southern" and "SME" do not have the same members; the Yellowstone Valley Electric Co-op and the City of Great Falls are members of Southern but not of SME. [Gessaman 9/30/09]

- The application is defective because it violates the requirements for the application to be truthful, accurate and complete. The developer is not Southern as the application shows, but SME Electric, the actual property owner and developer. [Liebert 9/30/09]

- There are currently two entities that are very closely connected and share similar names: Southern Montana Electric Generation and Transmission Cooperative (SME), and SME Electric. SME Electric was formed in June 2008, to move forward with development of the generation facility. One of the members of SME, Yellowstone Valley Electric Cooperative, was not interested in

pursuing a generation asset so the new SME Electric was formed that excluded YVEC and YVEC remains a member of SME. A similar situation exists with respect to the City of Great Falls. The City never joined the new SME Electric and has not joined the efforts to pursue a natural gas generation facility. The City is a member of SME however. Failure to properly identify the entity responsible for compliance at the generation facility could leave a member of SME liable for a project for which it is not legally responsible. The DEQ has a duty to issue an air permit to the proper entity, i.e., SME Electric. [MEIC 9/30/09]

Response: The application submitted to the Department reported the company name as "Southern Montana Electric Generation and Transmission Cooperative, Inc." as registered with the Montana Secretary of State. The permit document explicitly abbreviates "Southern Montana Electric Generation and Transmission Cooperative, Inc." to "SME" for ease of reading. This is the entity that has applied for the Montana Air Quality Permit and will be held liable to meet the conditions of the Montana Air Quality Permit #4429-00 if it becomes final. It is not uncommon for the Department to issue a permit to a company that is proposing to construct a facility on land that is not its own. The Department's review and analysis focuses on whether or not the company's proposal is capable of complying with the applicable rules and statutes.

Comment: Numerous inconsistencies exist in the presentation of information in the draft document. An example of such an inconsistency concerns water for the proposed gas plant (pg. 67, pg. 100, pg. 1). Also, pg. 1 of the permit analysis in inventorying permitted equipment mentions cooling towers yet the section of that page quoted above refers to a single cooling tower. [Gessaman 9/30/09]

Response: The Department has made further clarification to the water uses in the final EA. There are different types of water uses that are discussed in the EA and the Department has summarized the uses and clarified the descriptions for easy viewing and review. Also Bison on behalf of SME provided additional clarification that during simple cycle operation, there would be no cooling tower evaporation there would be 100 gpm of miscellaneous water use, and there would be no water discharge. During combined cycle operation, cooling tower evaporation would be 400 gpm, there would be 100 gpm of miscellaneous water use, and there would be 200 gpm of water discharge.

The Department has clarified in the permit analysis and EA that there are three cooling towers according to the information provided by SME; these towers would be grouped together as illustrated in Figure 2 of the EA. The three towers were modeled as three point sources for air emissions.

IMPACTS TO RECREATION

Comment: Proposed EA, pg. 33, Section 7.0 Recreation. NPS disagrees that the staging area offers no recreational activities, and disagrees with the conclusion that the staging area would not be significantly impacted. [NPS 6/11/09]

Response: NPS submitted this comment on the same day that SME submitted their response to incompleteness issues, where SME's responses included a viewshed analysis from the staging area. This analysis of the impacts to the viewshed from the staging area were subsequently disclosed in the Draft EA. The analysis suggested gas plant structures would not be visible from the staging area. The Department maintains that impacts to recreation would not be significant.

Comment: Proposed EA, pg. 33, Section 7.0 Recreation. *No other recreation facilities, parks, or opportunities are close to the Project site*. NPS finds this statement misleading because some private lands to provide for fishing along banks of the reservoir. There are a wide variety or recreational activities near Morony Reservoir and Morony Dam, e.g., hunting, fishing, paddling, boating and recreational trails. The EA overlooks and undervalues recreation in the project area. [NPS 6/11/09]

Response: Section 8.F of the Final EA has been revised to include the recreation activities addressed by NPS.

OTHER COMMENTS

Comment: Inclusion of a map(s) in the EA of the Great Falls Portage NHL and the placement of all HGS facilities, including all necessary infrastructure, would have been helpful for the public's review of potential impacts to the NHL. Information distributed by SME at the last Section 106 Consultation meeting on March 13, 2009 showed the natural gas plant facility footprint for the structures displayed in Figure 2 of the EA less than 500 feet from the NHL boundary. Roads and landscaping at the facility entrance were sited on the NHL in this handout. [NPS 9/30/09]

Response: On August 28, 2009, Bison Engineering provided an updated SME Project Overview Map. The Department has posted this map to the Department website at *http://www.deq.state.mt.us/AirQuality/AQinfo.asp*. According to this map, which reflects the most up-to-date information provided to the Department, the footprint of the gas plant structures appears to be approximately 2,500 feet from the NHL boundary.

Comment: DEQ must notify the Office of the Consumer Council. [MEIC, NPCA, SC 6/8/09]

Response: Montana Code Annotated (MCA) 69-2-216 requires the Department to notify the office of consumer counsel that it is in receipt of a permit for a new electrical generation facility, and also requires the consumer counsel to complete a customer rate impact analysis. However, MCA 69-2-217 exempts projects proposed by "utilities," as that term is defined in 69-8-103, where 69-8-103(33) defines utilities as both public and cooperative utilities. Cooperative utility is further defined in 69-8-103(4) as a qualifying utility pursuant to Title 35, section 18. As a result, the SME Cooperative proposal is exempt from the 69-2-216 rate impact analysis requirement. Regardless, the Department notified the consumer counsel that it was in possession of the SME application.

ERRORS

Comment: Proposed EA, pgs. 29 and 33. A contradiction in distance from the project to the Lewis and Clark Staging Area Interpretive Site (0.8 and 2 miles) should be corrected. [NPS 6/11/09]

Response: Section 8.F of the Final EA clarifies that the distance from the project to the staging area is approximately 2 miles.

Comment: Proposed EA, pg. 24, Table 5-1, Montana Species of Concern. Sauger is not listed on the table, but is included in discussion starting pg. 25. [NPS 6/11/09]

Response: The sauger was added to Table 19 in the Draft EA and Final EA to correct this omission.

Comment: Proposed EA, pgs. 24-25, Table 5-1 and Section 5.1.2. The bald eagle was reclassified as "taxon recovered" and removed from the threatened species list in 2007. EA should be updated to demonstrate that it is a new document and not a reiteration of the coal-fired plant document. [NPS 6/11/09]

Response: Table 19 in the Final EA has been edited to note that bald eagles were removed from the endangered species list in June 2007.

Comment: Proposed EA, pg. 46. The project site is in *Northeastern* Cascade County, please correct. [NPS 6/11/09]

Response: The project site was corrected to "northeastern" Cascade County in both the Draft EA and Final EA to correct this error.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

   Based on the emissions from the turbine, the Department determined that initial testing for NO_x and CO is necessary. Furthermore, based on the emissions from the turbines, the Department determined that annual testing is necessary to demonstrate compliance with the NO_x and CO emission limits.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   SME shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

SME must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, SME shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The turbine generators are considered NSPS affected equipment under 40 CFR Part 60 and are subject to the requirements of the following subparts.

   a. 40 CFR 60, Subpart A – General Provisions. This subpart applies to all equipment or facilities subject to an NSPS Subpart as listed below:

b. 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Combustion Engines (ICE). This subpart indicates that NSPS requirements apply to owners or operators of stationary CI ICE that commence construction after July 11, 2005, or are manufactured after April 1, 2006. This subpart also applies to fire pump engines manufactured and certified by the National Fire Protection Association after July 1, 2006. This subpart could apply to the proposed emergency generator/engine and the fire pump depending upon the manufacture date.

c. 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. This subpart applies to the proposed facility because SME proposes to install and operate stationary combustion turbines with a heat input greater than 10 million British thermal units (MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005.

8. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

a. 40 CFR 63, Subpart A – General Provisions apply to all equipment or facilities subject to an NESHAP Subpart as may be listed below:

b. 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines: This subpart applies to stationary combustion turbines located at a major sources of HAP emissions which emit any single HAP at a rate of at least 10 tons per year (TPY), or a combination of HAPs of at least 25 TPY. This subpart does not apply to the HGS gas plant because emissions from the HGS gas plant do not meet or exceed 10 TPY for a single HAP or 25 TPY for a combination of HAPs.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. SME must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed heights of the stacks for the turbine generators are below the allowable 65-meter GEP stack height.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. SME submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the potential to emit (PTE) greater than 25 TPY of any pollutant. The SME facility has a PTE greater than 25 TPY for NO_x, CO and $PM_{10}/PM_{2.5}$; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. SME submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. SME submitted an affidavit of publication of public notice for the April 25, 2009, issue of the *Great Falls Tribune*, a newspaper of general circulation in the City of Great Falls, in the County of Cascade, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving SME of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

12. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

13. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

14. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the BER or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

15. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

The proposed HGS gas plant is a major stationary source under the Prevention of Signficant Deterioration of Air Quality Program (PSD) because it belongs to the list of 28 source categories which emit or has the potential to emit 100 tons per year or more of any pollutant subject to regulation. The PSD source category that applies to the HGS gas plant is "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input" (ARM 17.8.801(22)). Emissions from the gas combustion turbines exceed 100 TPY for CO and NO_x. Furthermore, because the HGS gas plant is a major source with respect to PSD, emissions of PM and PM_{10} are considered "significant" because they exceed thresholds of 25 TPY for PM and 15 TPY for PM_{10}.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE > 100 TPY of any pollutant;

   b. PTE > 10 TPY of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. PTE > 70 TPY of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #4429-00 for SME, the following conclusions were made:

   a. Emissions from the HGS gas plant are greater than 100 TPY for NO_x and CO.

   b. Emissions from the HGS gas plant are less than 10 TPY for any one HAP and less than 25 TPY for all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. The HGS gas plant facility is subject to a current NSPS (40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines).

   e. The HGS gas plant is potentially subject to area source provisions of a NESHAP standard (40 CFR 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, depending on the date of manufacture of the emergency diesel generator and fire pump).

   f. The HGS gas plant is a Title IV affected source; however, it is not a solid waste combustion unit.

   g. The HGS gas plant is not an EPA designated Title V source.

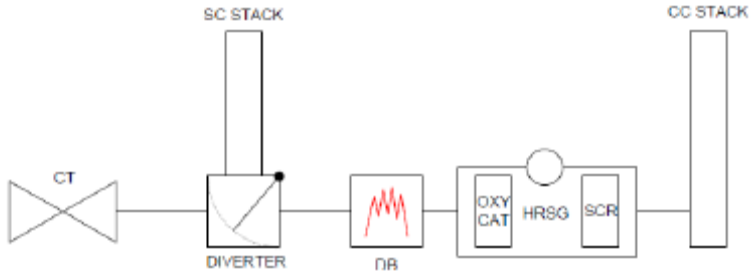
Based on these facts, the Department determined that SME is subject to the Title V operating permit program. SME applied for a Title V Operating Permit concurrent to the MAQP application.

III. BACT Determination

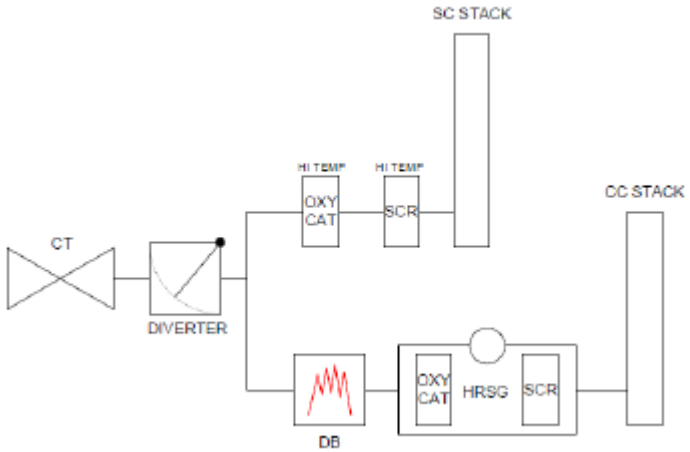
A BACT determination is required for each new or modified source. SME shall install on the new or modified source the maximum air pollution control capability which is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was submitted by SME in the application for MAQP #4429-00, addressing available methods of controlling NO_x, CO, SO_2, VOC, PM, PM_{10}, and $PM_{2.5}$ emissions from the turbine generators. The following analysis is a summary of SME's submittals and the Department's review and research. All of the SME application, the Department's incompleteness request, and subsequent submittals are available online at the following link: http://deq.mt.gov/AirQuality/WhatsNew/SME/SME%20Permit%20Application.asp. SME provided an analysis for multiple design scenarios in order to fully evaluate the economic impacts of installing catalytic oxidation for CO/VOC control and SCR for NO_x control. Summaries of the various design alternatives follow. Note that diagrams show only one turbine, but the facility would have separate and duplicate control systems dedicated to each of the two combustion turbines.

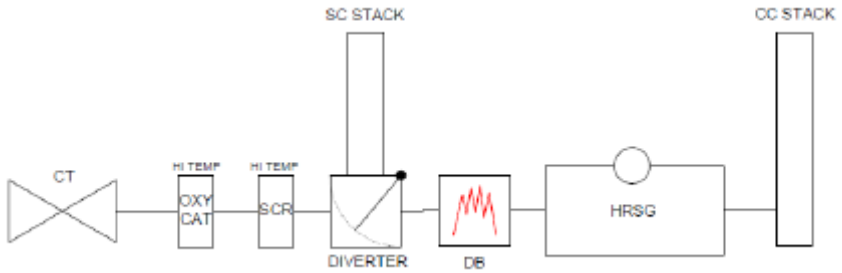
Case T1 – Simple cycle diverter, combined cycle controls. Case T1 is the proposed design configuration and is considered the base case for the facility. Two stacks would be installed. When operating in simple cycle mode, the exhaust would be diverted to the simple cycle stack without any add-on controls. When in combined cycle mode, the exhaust would be diverted to the duct burners and HRSG where the CO oxidation catalyst and SCR are installed. Less expensive, lower temperature catalysts can be used as the catalysts can be located exactly where they are most efficient in the HRSG, behind the superheater.



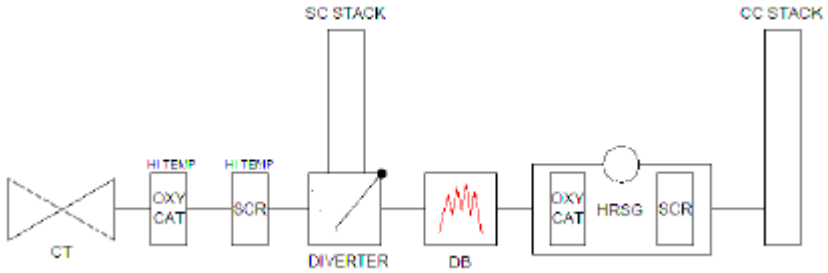
Case T2 – Parallel, duplicate controls systems. Case T2 represents duplicate SCR and oxidation catalyst systems installed in each flow path. For the simple cycle case, more expensive higher temperature oxidation and SCR catalyst would be required as they both experience full exhaust temperature from the turbine; i.e., energy is not removed from the HRSG superheater.



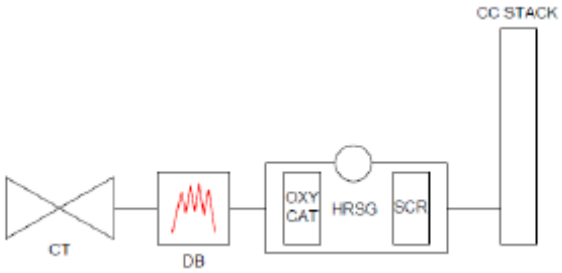
Case T3 – Shared controls. Case T3 represents the installation of the higher temperature catalysts before the simple cycle stack to control both simple cycle and combined cycle emissions of the combustion turbine. At issue with this case is that the emissions from the duct burners would be no longer reduced by any control device. The effective control efficiency of such a system would be inferior to the other cases analyzed. Higher temperature at the turbine exhaust is also not in the ideal catalyst range and may reduce abatement efficiency.



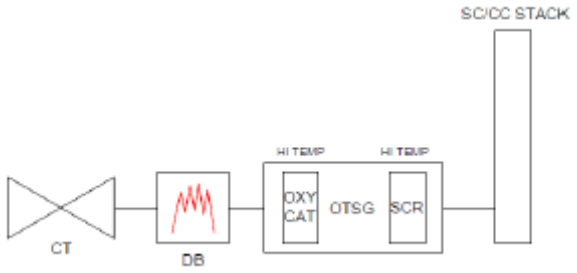
Case T4 – Simple cycle diverter, series controls. Case T4 represents the addition of controls for simple cycle mode, in addition to controls for combined cycle mode. In this case, all emissions, regardless of operating mode, would be controlled. At issue with this case is the significant back pressure added by duplicative controls, for little to no additional control. The additional backpressure reduces the performance of the turbine, significantly increasing the cost of electric power produced by the generating unit. The performance of the catalyst controls would be highly dependent on input pollutant concentrations; therefore, the second set of catalysts primarily would be for control of the duct burner emissions, as the concentrations of the turbine emissions are already reduced.



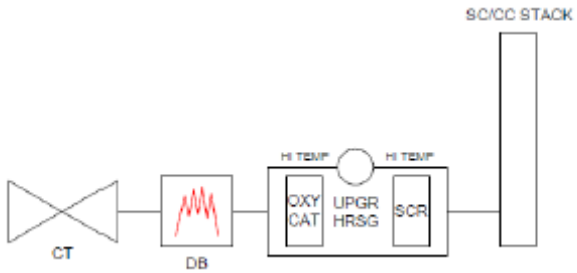
Case S1 – Eliminate simple cycle mode. Case S1 represents the removal of the simple cycle mode entirely, but this does not meet the mission of the gas plant and the need for electrical generation, and therefore is not considered for further analysis.



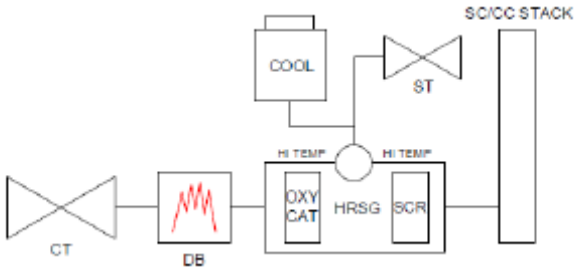
Case S2 – Once Through Steam Generator. Case S2 represents the installation of a once through steam generator (OTSG) in place of an HRSG. The fundamental design of an OTSG allows it to be run dry, which would be required for operation in simple cycle mode. Capital costs are typically higher for OTSG installations. Of particular concern is the sole-source procurement of such a steam generator. As sole-sourced, the OTSG for this facility could not be competitively bid, significantly driving up the cost of procurement.



Case S3 – Upgraded HRSG. Case S3 represents the procurement of an HRSG with upgraded metallurgy and designed for dry operation. Several HRSG manufacturers were contacted and indicated that such an HRSG was technically infeasible, that an OTSG would be necessary. Therefore, Case S3 is excluded from the analysis for technical infeasibility to control simple cycle emissions.



Case S4 – Steam Dump Condenser. Case S4 represents the installation of a steam dump condenser following the HRSG. In this case the simple cycle mode of operation is possible because the steam generated by the HRSG would then be condensed back to feedwater via the dump condenser. This presents only a partial solution as the beneficial startup times of simple cycle operation would be negated by the need to slowly heat the tubes of the HRSG. This case is highly undesirable as it is both expensive and energy wasteful, but is not technically infeasible, so it is carried through the BACT economic analysis.



A summary of the analysis for each control technology and design configuration is included below. The Department reviewed the proposed control methods, previous BACT determinations (via the EPA RACT/BACT/LAER Clearinghouse (RBLC) and the EPA Region 4 National Combustion Turbine Spreadsheet), and ongoing control proposals (via federal agencies and state agencies), before making the following BACT determination. When reviewing the RBLC and EPA Region 4 National Combustion Turbine Spreadsheet, the following search characteristics were used: Process Type of "15.000 – Large Combustion Turbines (>25 MW)." All facilities that were listed as aeroderivative turbines or that did not have enough information to discern turbine type were included as comparatives.

Note that the following sections address BACT for steady-state and transient operation; BACT for startup, shutdown, and commissioning operation is addressed in Section III.E.

A. NO_x BACT for Combustion Turbines

NO_x is formed during the combustion of natural gas. The formation of NO_x is dominated by the process called thermal NO_x formation. Thermal NO_x results from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. The rate of formation is sensitive to flame temperature and oxygen conditions.

The BACT analysis included analyzing the following controls for both simple cycle and combined cycle operation: SCR, EMx™, low temperature oxidation methods (including LoTOx™ and Xonon™), wet chemistry/NO_x scrubbers, DLN, water injection, selective non-catalytic reduction (SNCR) , fuel selection, proper design and operation, as well as some controls in combination (discussed in the NO_x BACT Summary section). A summary of these controls and feasibility of the controls with respect to the proposed aeroderivative turbines is provided below. The control efficiencies of the technologies are listed in the following table.

Table III.A.1 – Ranked NO_x Control Technologies

Control Technology	Percent Reduction
SCR	80-90%
EMx™	80-90%
LoTOx™ Low Temperature Oxidation	80-90%
Wet Chemistry/NO_x Scrubber	80%
DLN	51-71%
Water Injection	7-84%
SNCR	40-60%
Fuel Selection – Natural Gas Only	40%
Proper Design and Combustion	Base

1. Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for reduction of nitrogen oxide (NO) and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH_3) is used as the reducing agent. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Ammonia is injected into the flue gas upstream of a catalyst bed, and NO_x and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), noble metals (e.g., platinum and rhodium), zeolite, and ceramics.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the turbine exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the HRSG where the exhaust temperature has cooled to this temperature range. The control efficiency for an SCR is typically estimated to be between 80% and 90%. Technical factors that impact the effectiveness of this technology include inlet NO_x concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_x reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including pulverized coal (PC) and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of a particulate control device (e.g., baghouse). SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. For this application, the turbines will be combusting clean fuels (natural gas), and particulate loading is not anticipated to be a problem.

For simple cycle operation (based on 3,200 hours operation per year), the design configurations yielding the least expensive SCR control were T2, T3, and T4. For these configurations, it would cost $11,236 per ton to remove NO_x. At the Department's request, SME analyzed an additional design configuration that would route emissions from both turbines to a common SCR during simple cycle operation; this configuration yielded a cost effectiveness for NO_x removal of $11,376/ton. A review of the RBLC indicated that SCR is not a common application for control of NO_x during simple cycle operation of combustion generators. Furthermore, the economic impact of using SCR is considered disproportionately adverse relative to other recent BACT determinations. Therefore the Department determined that SCR is not considered BACT for simple cycle operation.

However, SME proposed the use of SCR for control of NO_x during combined cycle operation. For combined cycle operation (based on 8,760 hours per year), the cost to remove NO_x was calculated at $3,013/ton for the proposed configuration (T1), which is consistent with other BACT determinations that use SCR.

SCR presents several potentially adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip is expected to be low at this facility, approximately 10 parts per million (ppm) in order to adequately control NO_x during turbine load changes. Higher transient slip may result during large load ramping and other process upsets. Of primary environmental concern is the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. Ammonium sulfate emissions will be addressed in Section III.C in the $PM/PM_{10}/PM_{2.5}$ BACT analysis, but do not pose a prohibitive environmental impact.

There are also major considerations for the storage and use of large quantities of ammonia on the plant site. Ammonia is one of the regulated substances covered by Section 112(r) of the Clean Air Act, which deals with the prevention and detection of accidental releases of hazardous chemicals. This legislation is implemented through 40 CFR Part 68 – Chemical Accident Prevention Provisions. The quantity and concentration of aqueous ammonia stored on site is below the threshold quantities of 40 CFR Part 68, Table 1.

In terms of energy impacts, an SCR presents a small parasitic load on any combustion turbine upon which it is installed. In this case, 131 kW, or approximately 0.2% of combined cycle gross generation, would be required to operate SCR. These energy impacts would not eliminate SCR as a method to control NO_x during combined cycle operation.

Because there are no restrictions associated with economic, environmental, or energy impacts, the Department concurs that SCR constitutes BACT for control of NO_x emissions during combined cycle operation.

2. EMx™ Low Temperature Oxidation and Adsorption

EMx™, the second generation of $SCONO_x$, a multipollutant, postcombustion control technology. Originally developed by Goal Line Environmental Technologies, Emerachem, LLC now markets the technology under the tradename EMx™. EMx™ first oxidizes CO, VOC and NO. The resultant NO_2 is then adsorbed into a potassium carbonate coating on a catalyst. The buildup of subsequent potassium nitrites and nitrates must be removed during a catalyst regeneration cycle. The catalyst is separated from the exhaust stream, and a mixture of steam, CO_2 and natural gas (for hydrogen generation) are injected into the reaction chamber. The reducing gas reacts with the catalysis products to form elemental nitrogen and water vapor, leaving potassium hydroxide. Additional reaction with carbon dioxide (CO_2) converts the potassium hydroxide to potassium carbonate. The EMx™ catalyst is sensitive to sulfur poisoning and is usually preceded with a $SCONO_x$ catalyst to manage the sulfur compounds. NO_x control ranges from 80-90%.

According to EmeraChem, the cost of an EMx™ system would be approximately three times the cost of an SCR system. Because EMx™ technology would provide approximately the same NO_x control efficiency as SCR (i.e., 80-90%) but costs significantly more, the Department has determined that $SCONO_x$/EMx™ does not constitute BACT for either simple cycle or combined cycle operation.

3. Low Temperature Oxidation Methods (including LoTOx™ and Xonon™)

<u>LoTOx™</u>.

With DuPont BELCO's LoTOx™ NO_x control technology, oxygen is injected into the reaction chamber to transform NO and NO_2 into N_2O_3 or N_2O_5 using an ozone generator and a reactor duct. These higher nitrogen oxides are highly soluble in water, and can be removed from the exhaust stream as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts with a wet scrubber. Requirements of this system include oxygen and a cooling water supply. Also, the scrubber effluent treatment needs to be provided. LoTOx™ is specifically designed for high sulfur and particulate processes, as would be experienced in a refinery or coal-fired boiler. The estimated control efficiency of the system is 80-90%.

LoTOx™ has only been demonstrated on pilot scale projects, and none that involve combustion turbines. A review of the RBLC indicates three facilities nationwide using LoTOx™ for NO_x control: a steel foundry, an acid regeneration plant, and a refinery. As indicated by the manufacturer, LoTOx™ was specifically designed for use in high particulate and high sulfur content fuel combustion processes, unlike the combustion environment in a natural gas/liquid fuel-fired gas turbine. Due to these factors, the Department has determined that LoTOx™ does not constitute BACT for either simple cycle or combined cycle operation.

<u>Xonon™</u>.

Xonon™, originally developed by Catalytica Energy Systems, and now licensed to Kawasaki Heavy Industries, also reduces NO_x emissions by lowering combustion temperatures inside of the turbine. A lean mix of air and fuel is combusted in a premixing burner to heat the incoming combustion air. More fuel is then mixed into the incoming air and reacted on the catalyst surface without flame, combusting the mixture at very low temperatures and producing little NO_x. This technology has not been demonstrated in larger gas turbines, and is currently unavailable in sizes that support the generation needs of this facility.

The Xonon low temperature combustion catalyst has not been scaled for installation on turbines the size required by this facility. It has been demonstrated on small scale cogeneration turbines only (Kawasaki Heavy Industries M1A-13 1.4 MWe turbine). As the scale-up potential for this technology is not proven, the Department has determined that XONON does not constitute BACT for either simple cycle or combined cycle operation.

4. Wet Chemistry/NO_x Scrubber

A scrubbing system consists of several stages. In one stage, NO is oxidized to NO_2. In another stage, the NO_2 is quenched in order to induce chemical reactions in an aqueous phase. Chemical reactions are carried out in the second or subsequent stages in order to reduce NO_2 (i.e., to nitrogen (N_2), oxygen (O_2) and/or soluble salts).

Requirements of this system include chemical reagents and water treatment or chemical disposal provisions. The number of reagents and treatment requirements varies depending on design. Solutions are custom tailored to each source and operating characteristics. The estimated control efficiency of the multistage wet scrubber is around 80%.

For combined cycle operation, a NO_x scrubber is not considered BACT because SCR was selected, which offers equal-or-better control. For simple cycle operation, NO_x scrubbers are not found on combustion turbines according to the RBLC and the EPA Region 4 National Combustion Turbine Spreadsheet. These scrubbers are typically installed on aluminum anodizing and bright dip plants, precious metals refining, high alloy steel etching and chemical nitration facilities – processes that generate large concentrations of NO_x with a very small flowrate from acid bath cleaning/etching, not small concentrations with large flowrates from a gas turbine. The size of a NO_x scrubber required to obtain a sufficient resident time in the exhaust flow of a combustion turbine would be enormous, as would reagent and water requirements.

Although NO_x scrubbers are not listed as applied technology for gas turbines in the RBLC and EPA Region 4 National Combustion Turbine Spreadsheet, SME provided a least-cost economic screening analysis using the closest analogue available based on the cost of the two most common wet scrubbers: packet-bed and spray-chamber. (Note that these wet scrubbers are indicated for acid gas, VOC and PM control, not NO_x.) Based on EPA fact sheets for packet-bed and spray-chamber wet scrubbers, the annual least-cost of control is $2.50 per standard cubic feet per minute (scfm) (for spray-chamber). With the 80% control for NO_x scrubbers, approximately 42 tons/year would be removed. Each turbine generates 200,708 scfm exhaust (from GE), which results in a wet scrubber system annual least-cost of $501,700. Based on $501,700 annual least-cost and 42 tons removed, the annual least-cost per ton of control is $11,900.

The economic impact of using a NO_x scrubber is considered disproportionately adverse relative to other recent BACT determinations. The EPA Region 4 National Combustion Spreadsheet lists permit actions that deemed NO_x control costs of $10,000 per ton and above (including draft actions for South Mississippi Electric Power Association and Wisconsin Electric) as specifically cost prohibitive. Therefore the Department determined that a NO_x scrubber is not considered BACT for simple cycle operation.

5. Dry Low NO_x Burners (DLN)

DLN (also referred to as DLE by some turbine manufacturers) burners lower the combustion temperatures in the turbine, thereby reducing thermal NO_x formation. This is accomplished by lean premixing of fuel and combustion air prior to entry into the compressor, and injecting fuel in stages throughout the flowpath in the combustion turbine. This produces a lower

heating value gas/fuel mixture that will then combust at lower temperatures, reducing thermal NO_x. An added benefit to DLN is a lower heat rate, meaning more energy is generated for the same unit of fuel. The estimated control efficiency of DLN is 51-71%.

SME has proposed the use DLN as one component of BACT for NO_x control at this facility. Because there are no restrictions associated with energy, environmental, or economic impacts, the Department agrees that DLN is one component of BACT at this facility during both simple cycle and combined cycle operation.

6. Water or Steam Injection

Reducing the peak flame temperatures in the turbine combustion chamber will reduce thermal NO_x formation. Steam or water injection is a common coolant to be injected into the turbine. NO_x reduction is proportional to the amount of water or steam injected during operation. However, a balance must be reached, effectively limiting the NO_x reduction, due to reducing temperatures to the point of incomplete combustion and resultant increases in CO and VOC formation, flame instability and thermal stress on the engine. The estimated control efficiency of water injection is 7-84% (this control efficiency is highly variable based on turbine load).

The manufacturer of the proposed turbine offers a version that incorporates water injection with guaranteed NO_x emissions of 25 ppm. However, the turbine version proposed for the HGS gas plant utilizes DLN to achieve guaranteed NO_x emissions of 25 ppm. Therefore, the water injection turbine provides no better NO_x control, while incurring greater costs because it is less efficient than the DLN version. Due to this factor, the Department determined that water injection does not constitute BACT at this facility for either simple cycle or combined cycle operation.

7. Selective Non-Catalytic Reduction

SNCR involves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result.
The process has been used in North America since the early 1980s. Removal efficiencies of NO_x vary considerably for this technology, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip and the presence of interfering chemical substances in the gas stream. The estimated control efficiency for SNCR on the proposed process is 40%-60%.

The high temperatures required for operation of an SNCR system, typically between 1,650°F and 1,800°F, are above that of the exhaust temperatures generated with the proposed combustion turbines (typical temperatures range from 630°F to 970°F, depending on turbine load and inlet conditions). In order to achieve the high temperature required for efficient SNCR operation, significant amounts of fuel would need to be combusted to raise the temperature of the gas stream, far more than is possible with the duct burners designed for this facility. This would result in increased emissions without the benefit of utilizing the additional fuel combustion for electricity generation.

A review of the RBLC indicated that SNCR is not a common application for control of NO_x for turbine combustion generators in at least some cases because of the technical challenges and reduced efficiency discussed above. Due to these factors, the Department has determined that SNCR does not constitute BACT for either simple cycle or combined cycle operation.

8. Fuel Selection

The fuel of choice to operate the HGS gas plant is natural gas, widely recognized as a cleaner fuel than fuel oil. All emissions calculations and proposed BACT limits are based on natural gas combustion. The use of natural gas is capable of reducing NO_x emissions by up to 40% compared to other fuels.

SME has proposed the use of pipeline quality natural gas as one component of BACT for NO_x control at this facility. Because there are no restrictions associated with energy, environmental, or economic impacts, the Department agrees that the use of pipeline quality natural gas is one component of BACT at this facility during both simple cycle and combined cycle operation.

9. Proper Design and Operation

Fuel costs are a major portion of the cost of electricity generation. Consequently, every effort is made to conserve energy and thereby reduce costs. Efforts to maximize fuel efficiency also serve to reduce pollutant emissions; increasing the amount of electricity produced per unit of fuel decreases the amount of combustion-related pollutants emitted. This need must be balanced with the operating characteristics of the equipment selected and load behavior of the electrical network served by the proposed facility. Due to the potential for unpredictable load changes, a simple cycle-capable, rapid-ramping aeroderivative combustion turbine was determined to be necessary for this facility.

The proposed combustion turbine is available in two designs with NO_x guaranteed emission levels: a 15 ppm design and a 25 ppm design. SME has proposed using the 25 ppm design because it offers better reliability, lower maintenance costs due to less system vibration and better flame stability, and lower fuel use. Additionally, the 25 ppm turbine has higher output capacity, is more efficient and has superior exhaust characteristics in combined cycle mode.

In combined cycle mode, the 15 ppm version provides lower heat output prior to the HRSG, and therefore more fuel must be combusted in the duct burners to compensate for this lower thermal energy. Because of the additional fuel use associated with firing duct burners in the 15 ppm version, the incremental cost per ton of NO_x removed is $143,000/ton for the 15 ppm version, which is excessive when compared to other NO_x control technologies.

In simple cycle mode, costs incurred to install and operate a 15 ppm turbine are due to reduced efficiency and lost total generation capacity. The fuel opportunity cost is approximately $44,700 per year, and the lost capacity is 1.387 MW. Based on 3200 hours of simple cycle operation, this cost is approximately $305,000 per year. In total, the simple cycle 15 ppm turbine would cost an additional $350,000 per year. The incremental reduction in NO_x emissions would be approximately 24.4 tons per year, resulting in an incremental cost increase of approximately $14,300 per ton of NO_x emitted, which is excessive when compared to other NO_x control technologies.

SME has proposed the use of proper design and operation of the 25 ppm turbine as one component of BACT for NO_x control at this facility. Because there are no restrictions associated with energy, environmental, or economic impacts, the Department agrees that proper design and operation of the 25 ppm turbine design are one component of BACT for NO_x control at this facility during both simple cycle and combined cycle operation.

10. Summary of NO_x BACT for Combustion Turbines

Simple Cycle

For simple cycle operation, the combination of proper design and operation, combustion of pipeline quality natural gas, and use of DLN completes BACT for control of NO_x emissions. Other control technologies are not cost-effective during simple cycle operation, as discussed in following sections. The proposed simple cycle hourly NO_x limit is 36.58 pounds per hour (lb/hr) during steady state and transient operation, based on a one-hour average. The limit is based on a turbine manufacturer-guaranteed emission concentration of 25 ppm, which is converted to a lb/hr rate based on manufacturer test data over a range of potential operating loads and ambient temperatures which impact exhaust gas flow rate. The following table compares this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.A.2 – Simple Cycle NO_x Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
IL*	in review	Standard Energy Ventures - DuPage	PWPS FT-8 SWIFTPAC	WI, SCR	3.5	PPMVD	
WY-0066	4/20/2009	Medicine Bow IGL Plant	3ea 66 MW Turbines	SCR	4	PPM	30-day
FL-0261	10/26/2004	City of Tallahassee - Arvah B. Hopkins Gen Station		SCR, WI	5	PPM	---
KY*	under review	East Kentucky Power Cooperative - J. K.Smith Plant	GE LMS100	WI, SCR	5	PPM	1-hr
NV-0036	5/5/2005	TS Power Plant	Unknown	SCR, WI	6	PPMVD	3-HR
FL-0272	09/12/2005	Keys Energy Services Stock Island Power Plant		SCR, WI	9	PPM	---
		HGS Gas Plant	**LM6000PF**	**DLE, GCP, Fuel**	**25**	**PPM**	**1-HR**
FL*	in review	TECO Bayside Power Station	PWPS FT-8 SWIFTPAC	WI	25	PPM	
IL*	at notice	Rolls-Royce Power ventures - Lockport	Trent	DLN	25 60.4	PPM lb/hr	
LA-0219	8/15/2007	Creole Trails LNG Import Terminal	LM2500	DLE	25	PPM	
KS*	04-17-2007	Westar Energy - Emporia Energy Center	LM6000	WI	25	PPM	24-hr
OK-0127	6/13/2008	Western Farmers Electric Anadarko	GE LM6000	WI	25	PPMVD	
SC*	draft permit	Duke Energy - Lee Steam Station	LM6000	---	25	PPM	
WI-0240	1/26/2006	WE Energies Concord	Unknown	WI	25	PPM	
TX-0487	3/24/2005	Rohm and Haas Chemicals LLC Lone Star Plant	Unknown		27.46	lb/hr	
TX-0487	3/24/2005	Rohm and Haas Chemicals LLC Lone Star Plant	Unknown		42	PPM	
VI-0012	10/21/2004	VIWAPA - ST. THOMAS	Unknown	SI, WI	42	PPM	

*Permits/facilities identified by the EPA Region 4 National Combustion Turbine Spreadsheet

All six of the facilities with lower limits than was determined to be BACT for this facility require SCR as control. As indicated above, the installation of SCR at the HGS gas plant is not cost-effective for simple cycle operations based on the operational limit of 3200 hours;

therefore, fuel selection and DLN was selected as BACT. To protect this analysis, a condition is included in the permit action that would require re-evaluation of BACT if the 3200 hourly limit on simple cycle was removed.

Combined Cycle

When proper design and operation are used in combination with natural gas combustion, DLN, and SCR in combined cycle operation, the maximum level of NO_x reduction is achieved with up to 95% control efficiency. The proposed combined cycle hourly NO_x limit is 4.16 lb/hr during steady state and transient operation, based on a one-hour average. The limit is based on a control vendor-guaranteed emission concentration of 2.5 ppm, which is converted to a lb/hr rate based on test data over a range of potential operating loads and ambient temperatures which impact exhaust gas flow rate. The following table compares this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.A.3 – Combined Cycle NO_x Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
CA*	applic. under review	Ogden Pacific Power - Three Mountain Power	500 MW total	SCR	2.5	PPM	1-HR
		SME Gas Plant	**LM6000PF**	**DLE, SCR**	**2.5**	**PPM**	**1-HR**
NY-0093	03/31/2005	Trigen-Nassau Energy Corporation	LM6000	SCR	2.5	PPM	
TX*	In Review	Calpine Amelia		SCR	2.5	PPM	---
IL*	draft permit	Holland Energy	680 MW	SCR	3.5	PPM	24-HR
TX-0497	8/29/2006	Ineos Chocolate Bayou Facility		DLE, SCR	11.43 3.5	lb/hr PPM	3-HR
TX*	In Review	Channel Energy		SCR	3.5	PPM	---
IL*	draft permit	Holland Energy	680 MW	SCR	4.5	PPM	1-HR

*Permits/facilities identified by the EPA Region 4 National Combustion Turbine Spreadhsheet

NO_x emissions from the HGS gas plant in combined cycle operation are among the lowest of facilities reviewed.

B. CO/VOC BACT for Combustion Turbines

CO and VOCs are formed from incomplete combustion of organic constituents within the natural gas in the facility's combustion turbines. CO and VOC emissions are governed by an inverse relationship of exhaust concentration and turbine flowrate. When the turbine operates at high loads, combustion is more complete and concentrations are lower, but flowrates are at their highest. When the turbine operates at low loads, combustion is incomplete and concentrations tend to increase, but flowrates are reduced. Both cases may result in elevated mass emissions rates of CO and VOCs depending on the magnitude of the individual variables.

Because CO and VOC are generated and controlled by the same mechanisms, they will be addressed in this section together. In an ideal process, complete combustion, or oxidation, of organics results in the emission of water and CO_2. When organic compounds do not oxidize completely, the result is CO and various modified organic compounds. Two general and nonexclusive approaches are available for reducing emissions of these compounds:

- Improve combustion conditions to facilitate complete combustion in the turbine burner, and
- Complete oxidation of the exhaust stream after it leaves the turbine burner.

Post-combustion CO/VOC control is accomplished via add-on equipment that creates an environment of high temperature and oxygen concentration to promote complete oxidation of the CO and organic compounds remaining in the exhaust. This can be facilitated at relatively lower temperatures by the use of certain catalyst materials.

The BACT analysis included analyzing the following controls for both simple cycle and combined cycle operation: thermal oxidation, catalytic oxidation, and proper design and operation. A summary of these controls and feasibility of the controls with respect to the proposed aeroderivative turbines is provided below. The control efficiencies of the technologies are listed in the following table.

Table III.B.1 – Ranked CO/VOC Control Technologies

Control Technology	Percent Reduction	
	CO	VOC
Thermal Oxidizer	95-99%	95-99%
Catalytic Oxidizer	90-99%	30%
Proper Design and Combustion	Base	Base

1. Thermal Oxidation

   Thermal oxidizers are essentially supplementary combustion chambers that complete the conversion of CO/VOC to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. They require temperatures of approximately 1,800°F to 2,000°F. This high-temperature environment is produced by the combustion of supplemental fuel, generally natural gas. Thermal oxidizers are typically located downstream of a particulate control device, especially when the exhaust stream contains high concentrations of particulate material. Reduced particulate loading improves thermal efficiency since the particulate matter would act as a heat sink, and it reduces equipment maintenance requirements.

   Several design variations address different inlet concentrations, air flow rates, fuel efficiency requirements, and other operational variables. All of them function using the basic principles described above. One commonly used design is called a regenerative thermal oxidizer (RTO). This type of thermal oxidizer typically uses a bed of ceramic packing material to capture heat from the incineration process and preheat the incoming exhaust gas. This design improves thermal efficiency and reduces the amount of supplemental fuel that must be combusted. RTOs are capable of reducing CO/VOC emissions by 95 to 99 percent.

   For simple cycle operation (based on 3,200 hours operation per year as conditioned in the MAQP) use of RTO would cost $34,038/ton for CO removal and $804,126/ton for VOC removal. For combined cycle operation (based on 8,760 hours operation per year) use of RTO would cost $12,772/ton for CO removal and $280,444/ton for VOC removal. A review of the RBLC indicated that RTO is not a common application for control of CO/VOC for turbine combustion generators. Furthermore, the economic impact of using RTO is considered disproportionately adverse relative to other recent BACT determinations. Therefore, RTO is not considered BACT for either simple cycle or combined cycle operation.

2. Catalytic Oxidation

   Catalytic oxidizers employ the same principles as thermal oxidizers, but they use catalysts to lower the temperature required to effect complete oxidation. The optimum temperature range for catalytic oxidizers is generally 600 to 900°F. Because catalysts are prone to plugging and poisoning, catalytic oxidizers must be located downstream of a particulate control device if

the exhaust stream contains appreciable concentrations of particulate matter. Even so, contaminants that are not removed by the particulate control equipment, or those that are not removed in sufficient quantity, can potentially poison the catalyst and reduce or eliminate its effectiveness. For this application, the turbines will be combusting clean fuels (natural gas and ultra low-sulfur diesel fuel), and particulate loading is not anticipated to be a problem.

Like thermal oxidizers, catalytic oxidizer designs include many varieties to address specific operational conditions and requirements. They are generally capable of 90 to 99 percent destruction or removal efficiency at steady-state conditions.

For simple cycle operation (based on 3,200 hours operation per year as conditioned in the MAQP) a catalytic oxidizer would cost $7,438/ton for CO removal and $587,805/ton for VOC removal. A review of the RBLC indicated that catalytic oxidation is occasionally used for control of CO/VOC for simple cycle turbine combustion generators. However, for the proposed SME design and operation parameters, the economic impact of using a catalytic oxidizer for emissions control during simple cycle operation is considered disproportionately adverse relative to other recent BACT determinations. Therefore, the Department does not consider catalytic oxidation to be BACT for simple cycle operation.

However, SME proposed the use of catalytic oxidation for control of CO/VOC during combined cycle operation. Using a catalytic oxidizer for emissions control during combined cycle operation (based on 8,760 hours operation per year) would cost $2,682/ton for CO removal and $191,399/ton for VOC removal for the proposed design configuration. There are potentially adverse environmental impacts for a catalytic oxidizer due to handling of the spent catalyst since many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under the Resource Conservation and Recovery Act (RCRA). However, this is not enough to eliminate catalytic oxidation as a feasible alternative. No significant energy impacts result from the use of a catalytic oxidizer, as it is a passive control system.

3. Proper Design and Operation

Reduction of CO/VOC emissions can be accomplished by controlling the combination of system temperatures through operation at maximum loads, increasing oxygen concentrations, maximizing combustion residence time, and improving mixing of the fuel, exhaust gases, and combustion air (oxygen). Maximizing heating efficiency, and subsequently minimizing fuel usage, will also minimize CO formation.

4. Summary of CO/VOC BACT for Combustion Turbines

<u>Simple Cycle</u>
For simple cycle operation, proper design and operation constitutes the only component of BACT for control of CO/VOC, since other technologies are not economically feasible as discussed in the previous sections. The simple cycle hourly limit during steady state and transient operation is 48.96 lb/hr for CO and 2.03 lb/hr for VOC. The emission limits are based on turbine vendor test data, and represent worst-case emissions over a range of potential operating loads and ambient temperatures. The following tables (CO followed by VOC) compare this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.B.2 – Simple Cycle CO Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
FL-0261	10/26/2004	City of Tallahassee - Arvah B. Hopkins Gen. Station		OXY CAT	6	PPM	---
FL*	applic. under review	TECO Bayside Power Station	PWPS FT-8 SWIFTPAC	OXY CAT	6	PPM	
KY*	under review	East Kentucky Power Cooperative - J. K.Smith Plant	GE LMS100	OXY CAT	6	PPM	3-hr
NV-0036	5/5/2005	TS Power Plant	Unknown	Oxy Cat	6	PPMVD	3-HR
WY-0066	4/20/2009	Medicine Bow IGL Plant	3ea 66 MW Turbines	Oxy Cat	6	PPM	30-day
LA-0219	8/15/2007	Creole Trail LNG Import Terminal	LM2500	DLE	25	PPM	
FL-0272	9/12/2005	Keys Energy Services Stock Island Power Plant		---	30	PPM	---
		HGS Gas Plant	**LM6000PF**	**GCP**	**55**	**PPM**	**1-HR**
OK-0104	11/23/2004	Horseshoe lake Generating Station	GE LM6000PC	GCP	62.5	PPMVD	
OK-0127	6/13/2008	Western Farmers Electric Anadarko	GE LM6000		63	PPMVD	
IL*	in review	Standard Energy Ventures - DuPage	PWPS FT-8 SWIFTPAC	OXY CAT	0.0219	lb/MMBtu	
KS*	4/17/2007	Westar Energy - Emporia Energy Center	LM6000		36	lb/hr	
					0.0888	lb/MMBtu	
		HGS Gas Plant	**LM6000PF**	**GCP**	**48.96**	**lb/hr**	**1-HR**
					0.132	**lb/MMBtu**	**1-HR**
IL*	at notice	Rolls-Royce Power ventures – Lockport	Rolls-Royce Trent	DLN	60.4	lb/hr	
					0.156	lb/MMBtu	
KS*	4/17/2007	Westar Energy - Emporia Energy Center	LM6000		63.8	lb/hr	
					0.157	lb/MMBtu	
TX-0487	3/24/2005	Rohm and Hass Chemicals LLC Lone Star Plant	Unknown		38.53	lb/hr	
WI-0240	1/26/2006	WE Energies Concord	Unknown		20	lb/hr	
WI-0240	1/26/2006	WE Energies Concord	Unknown		300	lb/hr	

Six of the nine facilities with CO emissions lower than the HGS gas plant have oxidation catalysts installed. As demonstrated above, the installation of oxidation catalysts at the HGS glas plant is not cost-effective for simple cycle operations based on the proposed operational limit of 3200 hours per year. In addition, other factors, including average ambient temperatures (and temperature extremes in particular locations) play a factor in emissions limits. The HGS gas plant mass emission rate represents worst-case steady-state mass emissions across all loads and temperatures evaluated.

Table III.B.3 – Simple Cycle VOC Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
WY-0066	4/20/2009	Medicine Bow IGL Plant	3ea 66 MW Turbines	Oxy Cat	1.4	PPM	hourly
FL-0261	10/26/2004	City of Tallahassee - Arvah B. Hopkins Gen. Station		---	3	PPM	---
		HGS Gas Plant	**LM6000PF**		**4**	**PPM**	**1-HR**
FL-0272	9/12/2005	Keys Energy Services Stock Island Power Plant		---	8	PPM	---
LA-0219	8/15/2007	Creole Trail LNG Import Terminal	LM2500	GCP	1.21	lb/hr	hourly
					0.00417	lb/MMBtu	
		HGS Gas Plant	**LM6000PF**	GCP/Fuel	**2.03**	**lb/hr**	**1-HR**
					0.00549	**lb/MMBtu**	**1-HR**
TX-0487	3/24/2005	Rohm and Hass Chemicals LLC Lone Star Plant	Unknown		0.59	lb/hr	
WI-0240	1/26/2006	WE Energies Concord	Unknown		5	lb/hr	
WI-0240	1/26/2006	WE Energies Concord	Unknown		16	lb/hr	

Two of the three facilities with CO emissions lower than the HGS gas plant have oxidation catalysts installed. As demonstrated above, the installation of oxidation catalysts at the HGS glas plant is not cost-effective for simple cycle operations based on the proposed operational limit of 3200 hours per year. In addition, other factors, including average ambient temperatures (and temperature extremes in particular locations) play a factor in emissions limits. The HGS gas plant mass emission rate represents worst-case steady-state mass emissions across all loads and temperatures evaluated.

Combined Cycle

SME has proposed the use of proper design and operation as one component of BACT at this facility for control of CO/VOC during combined cycle operation. The Department deems proper design and operation as one component of BACT at this facility for control of CO/VOC during combined cycle operation.

Because there are no restrictions associated with economic, environmental, or energy impacts, the Department deems use of a catalytic oxidizer as BACT for control of CO/VOC emissions during combined cycle operation. The combined cycle hourly limits during steady state and transient operation are 2.03 lb/hr for CO and 1.86 lb/hr for VOC, based on a one-hour average time. The emission limits are based on control vendor-guaranteed emission concentrations of 2.5 ppm for CO and 6 ppm for VOC, which are converted to a lb/hr rate based on test data over a range of potential operating loads and ambient temperatures which impact exhaust gas flow rate. The following tables compare (first CO, then VOC) this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.B.4 – Combined Cycle CO Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
		SME Gas Plant	**LM6000PF**	**OXY CAT**	**2**	**PPM**	**1-HR**
CA*	applic. under review	Ogden Pacific Power - Three Mountain Power	500 MW total	Oxy Cat	4	PPM	3-HR
NY-0093	3/31/2005	Trigen-Nassau Energy Corporation	LM6000	OXY CAT	9	PPM	1-HR
NY-0093	3/31/2005	Trigen-Nassau Energy Corporation	LM6000	OXY CAT	12	PPM	1-HR
TX-0497	8/29/2006	Ineos Chocolate Bayou Facility		GCP	15	PPMVD	
TX*	In Review	Calpine Amelia		---	22	PPM	---
TX*	In Review	Channel Energy		---	25	PPM	---

Table III.B.5 – Combined Cycle VOC Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
		SME Gas Plant	**LM6000PF**	**GCP**	**1.86**	**lb/hr**	**1-HR**
					0.00416	**lb/MMBtu**	**1-HR**
TX-0497	8/29/2006	Ineos Chocolate Bayou Facility		GCP	6.14	lb/hr	
					0.00680	lb/MMBtu	

CO/VOC emissions from the HGS gas plant in combined cycle operation are among the lowest of facilities reviewed.

C. $PM/PM_{10}/PM_{2.5}$ BACT for Combustion Turbines

PM (including total particulate, PM_{10} and $PM_{2.5}$) emissions from combustion turbines originate from ash and sulfur contained within the fuel. Filterable PM emissions are inherently low through combustion of natural gas with its low ash and sulfur content. There is a lack of available vendor-provided $PM_{2.5}$ emission rates and appropriate test methods; nonetheless, the SME BACT analysis made the following conservative assumptions:

- All PM emissions are PM_{10},
- All PM_{10} emissions are $PM_{2.5}$.

In addition, all primary sulfate emitted from the turbines and sulfate converted via oxidation catalyst and SCR catalyst is assumed to react with available ammonia from the SCR to form ammonium sulfate. For purposes of this BACT analysis, this is a highly conservative approach and will likely over-estimate the emissions of $PM_{2.5}$ and the benefits of candidate control devices for consideration.

Additional constituents of indirect $PM_{2.5}$ emissions are the potential secondary precursors NO_x, SO_2, VOC, and NH_3. The criteria pollutants NO_x, SO_2, and VOC are addressed in other sections of this BACT analysis. EPA acknowledges that NO_x, SO_2, and VOC are criteria pollutants that are already regulated and typically subject to limits in an NSR permitting review. Therefore, regulation of these pollutants as precursors for $PM_{2.5}$ "is not expected to add a major burden to regulated sources." Because NO_x, SO_2, and VOC are fully evaluated in separate BACT analyses and controlled via add-on technologies and fuel selection that are considered BACT, they are not reevaluated as part of this $PM/PM_{10}/PM_{2.5}$ BACT analysis. NH_3 is the remaining potential secondary precursor, and is emitted in small quantities as a result of incomplete reaction in the SCR catalyst. According to EPA, VOC and ammonia are "presumed out" precursors of $PM_{2.5}$, therefore this ammonia slip is not a direct $PM_{2.5}$ pollutant and is not evaluated as such in this analysis.

The BACT analysis included analyzing the following controls for both simple cycle and combined cycle operation: fabric filters, electrostatic precipitators (ESP), cyclones or centrifugal collectors, wet scrubbers, fuel selection, and proper design and operation. A summary of these controls and feasibility of the controls with respect to the proposed aeroderivative turbines is provided below. The control efficiencies of the technologies are listed in the following table.

Table III.C.1 – Ranked PM/PM_{10}/$PM_{2.5}$ Control Technologies

Control Technology	Percent Reduction		
	PM	PM_{10}	$PM_{2.5}$
Fabric filters	99-99+%	99-99+%	99-99+%
ESP, wet and dry	90-99+%	90-99+%	90-99+%
Cyclones	80-99.9%	60-95%	20-80%
Wet Scrubbers	70-99+%	70-99+%	70-99+%
Fuel Selection – Natural Gas Only	Base	Base	Base
Proper Design and Combustion	Base	Base	Base

1. Fabric Filters (Baghouses)

   Fabric filters consist of one or more isolated compartments containing rows of fabric filter bags or tubes. Gas flows pass through the fabric where the particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. Filtering is accomplished through a combination of inertial impaction, impingement, and accumulated dust cake sieving. The captured particulate is typically removed from the filters via pneumatic pulses or by mechanical shakers.

   Fabric filters will collect particle sizes ranging from submicron to several hundred microns at gas temperatures up to about 500°F. Specialty bags, including intrinsically coated and membrane bags are required for stack temperatures above 500°F, and can be used to achieve lower particulate emission rates; however, specialty bags may cost significantly more than standard bags. The control efficiency for fabric filters ranges from 99-99.9% for PM, PM_{10}, and $PM_{2.5}$.

   Fabric filters can be categorized by several means, including types of cleaning devices (shaker, reverse-air, and pulse-jet), direction of gas flow, location of system fan, and gas flow quantity. Typically, the type of cleaning method distinguishes the fabric filter.

   Advantages to fabric filters are the high collection efficiency in excess of 99% for filterable particulate matter, and the collection of a wide range of particle sizes removed. The disadvantages are limits on gas stream temperatures above 550°F (for typical installations), high-pressure drops, difficulty handling gas or particles that are corrosive or sticky in nature, and minimal capture efficiency for condensable $PM_{2.5}$ fractions of the exhaust gas stream.

   Fabric filters control could be a potential particulate control device for a combustion turbine. No examples exist in the RBLC of a baghouse installed on combustion turbines for PM control. The concentration of PM in the exhaust gas from the combustion turbines is inherently low, with relatively high temperatures, leading to low capture efficiencies. In order to use cost-effective filter bags, a significant amount of additional tempering air will be required to reduce the temperature of the exhaust stream to a suitable range that promotes reasonable bag life. Careful analysis and design would be required to prevent temperature reduction of the exhaust stream below the dewpoint of any condensables in the exhaust. In addition, relatively expensive stainless steel construction would be required due to acid gas formation from SCR aqueous ammonia and fuel sulfur reactions. These reasons alone do not eliminate the installation of a baghouse based on technical infeasibility.

Based on the small amount of particulate available for control and the lack of add-on particulate devices for combustion turbines in the RBLC, a screening model was developed to identify the lowest potential economic impact of add-on particulate devices for combustion turbines. First, representative annual costs for each technology were collected from the appropriate EPA Air Pollution Control Fact Sheets. Next, the lowest specific cost value and highest control efficiency were applied to the following formula to produce the lowest possible cost-effectiveness result:

$$\text{Cost-effectiveness (\$/ton)} = \frac{\text{Exhaust flow rate (scfm)} * \text{Specific cost (\$/scfm)}}{\text{Uncontrolled annual emission rate (ton)} * \text{Control efficiency}}$$

Using this formula, the best-case minimum cost-effectiveness from any of the listed technologies was $14,140 per ton of particulate removed.

This is an unrealistically low value and would likely be much higher, because these technologies are not readily applied to a combustion turbine generating unit, requiring extensive design, engineering, and testing that would significantly increase costs above the screening values presented here. In addition, this analysis assumes that the EPA reported values are able to control condensable particulate $PM_{2.5}$ as well as filterable, which in reality is not the case. However, the analysis demonstrates that all of the identified alternatives would result in disproportionate adverse economic impacts. Furthermore, the RBLC does not list any add-on particulate control device for combustion turbines. Therefore, the use of fabric filters/baghouses does not constitute BACT for either simple cycle or combined cycle operation.

2. Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electric forces to move particles out the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane. ESPs are configured in several ways. The types described here are the plate wire precipitator, the flat plate precipitator, the tubular precipitator, the wet precipitator, and the two-stage precipitator.

The plate wire precipitator is the most common variety. It is commonly installed in coal-fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, and different varieties of furnaces. Plate wire precipitators are designed to handle large volumes of gas.

The flat plate precipitator is designed to use flat plates instead of wires for high-voltage electrodes. Small particle sizes with low-flow velocities are ideal for the flat plate precipitator. The flat plate precipitator usually handles gas flows ranging from 100,000 to 200,000 actual cubic feet per minute (acfm).

Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators have typical applications in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants.

Wet precipitators can be any of the three previously discussed precipitators but with wet walls instead of dry walls. The advantage of a wet precipitator is particles are not reentrained due to the rapping of the walls common to dry precipitators. The disadvantage is the complexity of the wash, handling and disposal of the slurry.

Finally, two-stage precipitators are parallel in nature (i.e., the discharge and collecting electrodes are side by side). Two-stage precipitators are designed for indoor applications, low gas flows below 50,000 acfm, and submicrometer sources emitting oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are considered separate and distinct types of devices used in very specific applications.

ESPs, except for the plate wire precipitator, are designed to handle relatively small volumes of gas. Although a plate wire precipitator could potentially handle the large volume of gas from a simple cycle combustion turbine, the plate wire precipitator has not been installed for any natural gas turbine. In addition, both wet and dry ESPs are very sensitive to fluctuations in exhaust stream characteristics. Flow rates, temperatures and subsequently particulate loadings will vary significantly in the operation of these turbines. The RBLC does not list any type of ESP as a particulate control device for combustion turbines. Despite these limitations, ESPs cannot be eliminated as technically infeasible. The control efficiency for ESPs (wet and dry) ranges from 90-99+% for PM, 90-99+% for PM_{10}, and 90-99+% for $PM_{2.5}$.

As shown in the fabric filter/baghouse section, all particulate control technologies result in adverse economic impacts, and none are listed in the RBLC for control of combustion turbines. Therefore, the use of an ESP does not constitute BACT for either simple cycle or combined cycle operation.

3. Centrifugal or Cyclone Precipitators

Centrifugal, or cyclone, precipitators are used as a "prefilter" before the primary particulate control device. They are also used to capture and recycle high-value process material. While cyclones are generally more effective at removing larger particles than smaller ones, cyclones have been designed to remove filterable $PM_{2.5}$ with up to 70 percent efficiency. At high removal rates, increased power requirements due to increased pressure drop become a significant consideration. The control efficiency for cyclones ranges from 80-99% for PM, 60-95% for PM_{10}, and 20-80% for $PM_{2.5}$.

As shown in the fabric filter/baghouse section, all particulate control technologies result in adverse economic impacts, and none are listed in the RBLC for control of combustion turbines. Therefore, the use of centrifugal precipitators does not constitute BACT for either simple cycle or combined cycle operation.

4. Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as venturis and spray chambers. When using interception, particles flow nearly parallel to the water droplets, which allows the water to capture the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturis employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where there is a high temperature difference between the gas and the scrubbing liquid. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

Six particle scrubber designs are used in control applications: spray, wet dynamic, cyclonic spray, impactor, venturi, and augmented. In all of these scrubbers, impaction is the main collection mechanism for particles larger than 3 microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets is needed to trap the particles. This is done at the price of high-energy consumption due to hydraulic or velocity pressure losses.

Due to the sheer number of wet scrubber design types, a specially designed wet scrubber could potentially act as a particulate control device for the combined cycle turbines. However, wet scrubbers have not been listed by the RBLC as a particulate control device for combustion turbines, and per the EPA OAQPS Cost Control manual, existing wet scrubbers designed for PM control support exhaust flow rates significantly below the flows expected for these turbines. Despite these statements, wet scrubbers cannot be eliminated on technical infeasibility. The control efficiency for wet scrubbers ranges from 70% to over 99% for PM, PM_{10}, and $PM_{2.5}$.

As shown in the fabric filter/baghouse section, all particulate control technologies result in adverse economic impacts, and none are listed in the RBLC for control of combustion turbines. Therefore, the use of wet scrubbers does not constitute BACT for either simple cycle or combined cycle operation.

5. Fuel Selection

A majority of $PM_{2.5}$ emissions is ammonium sulfate [$(NH_4)_2SO_4$]. Because SME is proposing SCR for NO_x control, the required aqueous ammonia reacts with available fuel sulfur (in the form of converted sulfate) to form ammonium sulfate. The reaction for this formation is detailed below:

$$aSO_2 + \text{Catalyst (oxidation and SCR)} + bH_2O \rightarrow cH_2SO_4$$
$$dNH_3 + eH_2SO_4 \rightarrow f(NH_4)_2SO_4$$

Normally, the oxidation of SO_2 to sulfate (SO_4) is a photoreactive process that occurs over a period of time downrange in a dispersion plume. The turbine vendor has provided the fractionation of primary SO_2 and SO_3 emissions from the turbine. In addition, the vendor has provided the proportion of SO_2 that is expected to be oxidized to SO_3 by the SCR and CO oxidation catalysts. For this analysis, we have conservatively assumed that all primary and converted SO_3 rapidly oxidizes to SO_4, and is available for ammonium sulfate formation before the stack outlet.

The selection of pipeline quality natural gas fuel significantly reduces the fuel sulfur content, thus removing the majority of the $PM_{2.5}$ precursor. Fuel selection of low sulfur pipeline quality natural gas is a simple and widely accepted method for control of both $PM_{2.5}$ and SO_2. Due to the inherent low ash and sulfur contents of pipeline quality natural gas little uncontrolled particulate matter is emitted by this facility. Despite the high control efficiencies of some of the evaluated particulate controls, the add-on control technologies are not cost-effective when only 32 tons per year of total particulate is to be emitted by each of the turbines. Based on the high cost effectiveness of the best case screening value of \$14,140/ton of $PM/PM_{10}/PM_{2.5}$, the addition of any add-on control is not cost-effective. The high volumetric flowrate with a relatively low particulate loading of the exhaust gas makes the total annualized cost of the particulate control device an impractical pollution control device for a combustion turbine. Furthermore, RBLC does not list any add-on particulate control device for combustion turbines. The remaining control option is to utilize clean fuels like pipeline quality natural gas. SME has proposed the use of pipeline quality natural gas as one component of BACT for $PM/PM_{10}/PM_{2.5}$ control at this facility.

6. Proper Design and Operation

As previously mentioned, fuel costs are a major portion of the cost of electricity generation. Consequently, every effort is made to conserve energy and thereby reduce costs. SME will operate these turbines to maximize efficiency and minimize idling when system loads permit.

SME has proposed the use of proper design and operation as one component of BACT for $PM/PM_{10}/PM_{2.5}$ control at this facility. Because there are no restrictions associated with energy, environmental, or economic impacts, the Department concurs that proper design and operation is one component of BACT at this facility for both simple cycle and combined cycle operation.

7. Summary of $PM/PM_{10}/PM_{2.5}$ BACT for Combustion Turbines

The use of pipeline quality natural gas in addition with the use of proper design and operation has been selected as BACT for $PM/PM_{10}/PM_{2.5}$ for this project. The hourly limits determined to be BACT during steady state and transient operation are 4.80 lb/hr during simple cycle operation and 7.20 lb/hr during combined cycle operation, based on a one-hour average. The limits are based on worst case turbine vendor test data for particulate matter generation over a range of operating loads and ambient temperatures (4.0 lb/hr for simple cycle operation and 6.41 lb/hr for combined cycle operation), plus the contribution of ammonium sulfate production (0.80 lb/hr for simple cycle operation and 0.80 lb/hr for combined cycle operation). The following tables compare this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.C.2 – Simple Cycle $PM/PM_{10}/PM_{2.5}$ Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
TX-0487	3/24/2005	Rohm and Hass Chemicals LLC Lone Star Plant	Unknown		2.09	lb/hr	
LA-0219	8/15/2007	Creole Trail LNG Import Terminal	LM2500	DLE	2.11	lb/hr	hourly
					0.00728	lb/MMBtu	
FL-0261	10/26/2004	City of Tallahassee - Arvah B. Hopkins Gen. Station		---	2.45	lb/hr	---
					0.00551	lb/MMBtu	
OK-0127	6/13/2008	Western Farmers Electric Anadarko	GE LM6000	GCP, Fuel	4	lb/hr	
					0.00864	lb/MMBtu	
		SME Gas Plant	**LM6000PF**	GCP, Fuel	**4.8**	**lb/hr**	**1-HR**
					0.0130	**MMBtu/hr**	**1-HR**
WY-0066	4/20/2009	Medicine Bow IGL Plant	3ea 66 MW Turbines	GCP	10	lb/hr	hourly
NV-0036	5/5/2005	TS Power Plant	Unknown	Fuel	13.7	lb/hr	24-HR
					0.0367	lb/MMBtu	
FL-0272	09/12/2005	Keys Energy Services Stock Island Power Plant		---	25 front & back half 13.9 front	lb/hr	---
					0.0576037	lb/MMBtu	

As demonstrated above, all evaluated add-on $PM/PM_{10}/PM_{2.5}$ control technologies are not cost effective for simple cycle operations. The HGS gas plant mass emission rate represents worst-case steady-state mass emissions across all loads and temperatures evaluated. In addition, as described in Section III.C, the presumptive formation of ammonium sulfate has been added to the emission rate provided by the turbine manufacturer. Because SME has added the ammonium sulfate formation to the particulate emissions, the mass emission rate proposed for the gas plant is higher than those estimates calculated using only PM/PM_{10}.

Table III.C.3 – Combined Cycle $PM/PM_{10}/PM_{2.5}$ Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
		SME Gas Plant	**LM6000PF**	**GCP/Fuel**	**7.2**	**lb/hr**	**1-HR**
					0.0161	**lb/MMBtu**	**1-HR**
TX-0497	8/29/2006	Ineos Chocolate Bayou Facility		Fuel Selection	10.03	lb/hr	
NY-0093	03/31/2005	Trigen-Nassau Energy Corporation	LM6000		8.42	lb/hr	
					0.0128	lb/MMBtu	

$PM/PM_{10}/PM_{2.5}$ emissions from the HGS gas plant in combined cycle operation are among the lowest of facilities reviewed.

D. Sulfur Dioxide BACT for Combustion Turbines

Sulfur is present in natural gas and ultralow sulfur diesel as organic sulfur compounds. In these forms it is readily volatilized under combustion conditions and is then oxidized by the oxygen present in the combustion and exhaust air to SO_2. SO_2 emissions can be reduced by limiting or preventing SO_2 formation and by capturing then converting it once it has formed.

The BACT analysis included analyzing the following controls for both simple cycle and combined cycle operation: supplemental scrubbing, chemical absorption, fuel selection, and proper design and operation. A summary of these controls and feasibility of the controls with respect to the proposed aeroderivative turbines is provided below.

1. Supplemental Scrubbing

It is possible that the exhaust gases could be exposed to additional scrubbing following the SCR to remove additional SO_2. A variety of reagents are available for reaction with SO_2. A large majority of flue gas scrubbers use either lime or limestone. Mixing techniques vary somewhat, but fall into two main categories: wet systems and dry systems. Wet systems use a reagent slurry that is typically brought into contact with the flue gas in a scrubber spray tower or packed bed. Dry systems spray or atomize the reagent into the flue gas stream to achieve the required contact. Many dry systems are actually referred to as semi-dry systems, and inject a high-solids slurry into a spray chamber where it contacts the flue gas stream. The hot flue gas vaporizes the water, leaving a dry particulate which either settles out in the spray chamber or is entrained in the flue gas stream and captured by a downstream particulate control device.

Supplemental scrubbing requires a method of collecting the particulate generated by reaction of fuel sulfur and the injected lime or limestone. The simplest and most inexpensive means of capture would be a fabric filter baghouse. As previously discussed, a baghouse was not a cost-effective control for a $PM/PM_{10}/PM_{2.5}$ with an emission removal rate of about 32 tons/year. The emissions inventory for sulfur dioxide is much less (≈ 3.0 tons/year). It is clear that if a device is not cost-effective for removing 32 tons/year of a pollutant, it is even less cost-effective for removal of less than 3.0 tons/year before the consideration of the costs associated with an actual SO_2 removal device. As a result, no detailed analysis is offered in this section given the prior particulate control analysis. Furthermore, no applications of SO_2 scrubbing can be found for combustion turbines. Therefore, the use of supplemental scrubbing does not constitute BACT for either simple cycle or combined cycle operation.

2. Aqueous Chemical Absorption

Aqueous chemical systems have been successfully employed in various industries to remove SO_2 from concentrated waste streams. These systems are similar to the dry scrubbers described above except they use aqueous solutions or slurries as the contact and reaction media. Two examples of such systems are the double alkali method and the commercial Tri-NO_x Multi-Chem® scrubber (by Tri-Mer Corporation).

This type of technology is not considered to be effective for large sources with dilute SO_2 concentrations. For example, the Tri-NO_x Multi-Chem® system has not been applied to systems with air flow rates above 60,000 cfm; the combined exhaust flow rate from each of the turbines is approximately fifteen times that amount at full load. Aqueous chemical absorption cannot be considered applicable to the proposed project and is not technically feasible. Furthermore, no applications of chemical SO_2 absorption can be found for combustion turbines. Therefore, the use of aqueous chemical absorption does not constitute BACT for either simple cycle or combined cycle operation.

3. Fuel Selection

The fuel used to fire the combustion turbines is the primary source of sulfur, and ultimately, of SO_2. Pipeline quality natural gas contains very little sulfur. Significantly reduced sulfur emissions result when combusting pipeline quality natural gas in a combustion turbine. Fuel selection to reduce SO_2 emissions is technically feasible within certain practical bounds. Ample supplies of pipeline quality natural gas are available for this facility at the proposed location. The proposed turbines are well tested combusting the fuel proposed.

The use of pipeline quality natural gas is feasible. The Department has determined that it makes up one part of SO_2 BACT at this facility for both simple cycle and combined cycle operation. Low sulfur fuels are well supported as BACT in the RBLC.

4. Proper Turbine Design and Operation

As mentioned, fuel costs are a major portion of the cost of electricity generation. SME will operate these turbines to maximize efficiency and minimize idling when system loads permit.

SME has proposed the use of proper design and operation as one component of BACT for SO_2 control at this facility. The Department agrees that proper design and operation are one component of BACT for this facility for both simple cycle and combined cycle operation.

5. Summary of SO_2 BACT for Combustion Turbines

The Department determined that SO_2 BACT for the combustion turbines is the combination of pipeline quality natural gas and proper turbine design and combustion. The associated per-stack hourly BACT limits during steady state and transient operation are 0.57 lb/hr during simple cycle operation and 0.69 lb/hr during combined cycle operation, based on a one-hour average. The limits are based on the maximum turbine heat rate, which in turn determines maximum fuel combustion, and thus sulfur availability for SO_2 formation. The assumed fuel sulfur content of pipeline quality natural gas is 0.5 grains of sulfur per 100 standard cubic feet (gr/100 scf) (40 CFR 72.2). Note that although it is assumed that ammonium sulfate will be formed prior to the stack outlet, instead of a photodependent reaction downrange, the fuel sulfur that may be converted to ammonium sulfate is not subtracted from the sulfur oxide (SO_x) emissions of the facility. This assumption may serve to overestimate particulate and sulfur emissions, but provides a maximum/conservative emissions estimate. The following tables compare this determination with others available from the RBLC and the EPA Region 4 Combustion Turbine Spreadsheet.

Table III.D.1 – Simple Cycle SO_2 Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
TX-0487	3/24/2005	Rohm and Hass Chemicals LLC Lone Star Plant	Unknown		0.03	lb/hr	
		SME Gas Plant	**LM6000PF**	**Fuel**	**0.57**	**lb/hr**	1-HR
					0.00154	**lb/MMBtu**	1-HR
WY-0066	4/20/2009	Medicine Bow IGL Plant	3ea 66 MW Turbines	Fuel	2.5	lb/hr	hourly
FL-0261	10/26/2004	City of Tallahassee - Arvah B. Hopkins Gen. Station		Fuel	1.13	lb/hr	---
					0.00254	lb/MMBtu	
WI-0240	1/26/2006	WE Energies Concord	Unknown	Fuel	0.00680	lb/MMBtu	
FL-0272	09/12/2005	Keys Energy Services Stock Island Power Plant		Low Sulfur Fuels	23.6	lb/hr	---
					0.0544	lb/MMBtu	
NV-0036	5/5/2005	TS Power Plant	Unknown	S in Fuel	500	PPM	
VI-0012	10/21/2004	Viwapa - St. Thomas	Unknown	S in Fuel	1500	PPM	

As demonstrated in Section III.D, all evaluated add-on SO_2 control technologies are not cost-effective for simple cycle operations. As explained above, the SO_2 emission rate is based on the definition of fuel sulfur in 40 CFR 72.2. The 0.57 lb/hr is among the lowest emission rate of the applicable facilities analyzed from the RBLC and EPA Region 4 National Combustion Turbine Spreadsheet.

Table III.D.2 – Combined Cycle SO_2 Control Technologies/Limits Comparison

RBLC ID	Permit Date	Facility Name	Turbine Type	Control	Limit	Units	Avg
		SME Gas Plant	**LM6000PF**	**Fuel**	**0.69**	**lb/hr**	**1-HR**
					0.00154	**lb/MMBtu**	**1-HR**
TX-0497	8/29/2006	Ineos Chocolate Bayou Facility		Fuel	12.66	lb/hr	
					0.0140	lb/MMBtu	

SO_2 emissions from the HGS gas plant in combined cycle operation are among the lowest of facilities reviewed.

E. BACT during Startup/Shutdown and Combined Cycle Commissioning Periods

<u>Startup/Shutdown (SUSD)</u>

Emissions from the generating units differ whether the turbines are starting up, operating at steady-state, or shutting down, and whether the duct burners are firing or not. In simple cycle operation, the combustion turbines are capable of a 10 minute cold startup to full load operations. The DLN system will stabilize and can begin controlling NO_x emissions within several minutes of a cold-start. Total mass emissions during simply cycle SUSD events were provided by the turbine vendor, and converted to hourly rates based on the SUSD duration.

The startup period for combined cycle operations requires more time than a simple cycle startup. In order to maximize energy transfer in the HRSG during nominal steady state operations, the thickness of the heat exchange tubes is relatively thin. The rapid temperature increase that would be experienced from a 10 minute cold-start simple cycle start would damage the thin heat exchange tubes. Therefore, the duration of the combined cycle startup and shutdown are extended to allow the heat exchange surfaces ample time to evenly heat, preventing damage.

Because the combined cycle SUSD duration is extended, emissions are generally greater than a simple cycle startup. The air pollution environmental controls proposed for this project depend on catalyst temperatures for proper function. Because the heat exchange surfaces must be slowly and evenly heated, the oxidation and SCR catalysts remain at lower temperatures longer, and begin controlling the emissions of the exhaust stream at a later time than during a simple cycle startup.

SME calculated mass emissions during the combined cycle startup because the HRSG and air pollution control vendors were not able to provide these emissions. In order to calculate these mass emissions, the instantaneous mass emission rate was calculated for each minute of the SUSD, and then summed-by-parts for the duration of the SUSD period. It was assumed that the HRSG would be heated (and thus, the air pollution controls) at the maximum safe rate to both prevent damage to the heat exchange surfaces, and ensure that the air pollution controls reach operational temperature as soon as practicable.

As far as the turbine emissions are concerned, the exhaust concentrations from a combined cycle SUSD are no different than a simple cycle SUSD. What is different is the duration of the "ramping" portion of the SUSD cycle. The turbine will still proceed through the hydraulic spin-up, fire-on and flame stabilization periods, at the same rate as a simple cycle startup. The ramp-up to base load will be "extended" up to two hours for the combined cycle startup. Because the HRSG has a known maximum linear heat input rate, the temperature of the air pollution controls and corresponding capacity for emissions control can be calculated (the controls vendor provided a performance graph indicating the % reduction expected at various temperatures). Coupled with the known turbine exhaust concentration, the mass emissions during combined cycle startup were calculated. From the mass emission, the hourly rates were derived based on the duration of the combined cycle SUSD event.

Because emissions during startup and shutdown tend to be higher, proper design and operation includes an annual limit on the number of hours spent in combined cycle startup and shutdown. When in combined cycle, two startup/shutdown cycles per day accommodate typical operation, where each startup may extend up to two hours, and each shutdown may extend up to one hour. Based on this assumption, each turbine will be limited to 1,460 hours of combined cycle startup time per rolling 12-month average (2 hrs/startup * 2 cycles/day * 365 days), and 730 hours of combined cycle shutdown time per rolling 12-month average (1 hr/shutdown * 2 cycles/day * 365 days). There is no limit for simple cycle startup/shutdown because, by intended application and design, simple cycle turbines may cycle on and off repeatedly throughout a day. Hourly limits are shown in the following table, based on a one-hour average.

Table III.E.1 Startup/Shutdown Emission Limits (lb/hr), per stack

Pollutant	Simple Cycle		Combined Cycle	
	Startup	Shutdown	Startup	Shutdown
NO_x	36.58	36.58	26.12	12.33
CO	114.70	114.70	76.20	4.15
VOC	3.90	3.90	1.86	1.86
SO_2	0.57	0.57	0.69	0.69
$PM/PM_{10}/PM_{2.5}$	4.80	4.80	7.20	7.20

The Department agrees that proper design and operation, and annual limits on combined cycle startup and shutdown time, constitute BACT during startup and shutdown operation.

Commissioning

"Commissioning" refers to the period of time following the first episode of fuel combustion in a new or refurbished turbine any time that a turbine is installed or re-installed at the facility. During generating unit installation and any maintenance that requires removal and/or replacement of a combustion turbine, SME requested a commissioning period to tune the combined cycle operation environmental controls.

The commissioning period and associated limits would only apply to the combined cycle mode of operation since simple cycle operation does not utilize post-combustion control. The ammonia injection grid controls for the SCR units will arrive with a factory-calculated operation program from the vendor. Actual turbine operations are required to fine-tune the feedforward and feedback loops to attain maximum control efficiencies. This procedure will be performed on each turbine independently. The commissioning period is expected to last 16 weeks per turbine from first firing.

During the commissioning period, it is not practicable to operate the turbines and the controls at maximum efficiency. It is conceivable that the turbines may operate for periods of time without SCR and oxidation catalyst control during the commissioning period, and that when controls are operated, they will not be 100% effective. Rigorous testing is required to fine-tune operations and ensure various monitoring systems are operational, feedback systems perform as required, etc. For purposes of emissions, therefore, it is not possible to identify meaningful emissions during a period of constant change in a progression towards normal operation. Therefore, the BACT-equivalent emission limits need to be relaxed to reflect numerous testing conditions during this traditional start-up period, and limits are based on the simple cycle mode of turbine operation.

SME has proposed that BACT during the commissioning period be equivalent to the simple cycle- and combined cycle-specific BACT determinations identified previously for normal operations; i.e., the installation and operation of DLN, SCR, and catalytic oxidation systems prior to commissioning, and operate the controls as best as practicable during the period given the testing nature of the commissioning activities. Hourly limits are shown in the following table, based on a one-hour average.

Table III.E.2 Combined Cycle Commissioning Period Emission Limits (lb/hr), per stack

Pollutant	Combined Cycle
NO_x	36.58
CO	114.70
VOC	3.90
SO_2	0.69
$PM/PM_{10}/PM_{2.5}$	7.20

The Department agrees that the installation of controls, proper design and operation of controls as practical, and a commissioning period not to exceed 16 weeks constitutes BACT during any commissioning period for combined cycle operation.

F. BACT for Emergency Generator and Emergency Fire Water Pump

SME is proposing the ability to operate the black-start emergency generator and emergency fire pump on diesel fuel. The emergency generator and emergency fire pump will only run during emergencies and during required maintenance and will be limited to 500 hours per unit per year.

Due to intermittent and infrequent use of the black-start generator and fire pump, pollution controls such as SCR, SNCR, scrubbers, ESP, and catalytic oxidizers will not operate properly and efficiently because these controls require steady-state operating conditions. Fabric filter baghouses are technically infeasible control options because the exhaust temperature is too hot for high temperature bags. When these controls are not operated at optimal efficiency and the annual hours of operation are limited to less than 500 hours per year, these control options become cost prohibitive.

Because all other control options are eliminated, SME proposes BACT for the emergency generator and fire pump as proper design and operation with limited hours of operation. Industry norms and previous BACT determinations do not require catalyst or other add-on controls on standby and emergency equipment because of the limited hours of operation and infrequent use. Therefore, the Department agrees that proper design and operation, and operation limits of 500 hours per unit per year constitute BACT for the emergency generator and fire pump.

IV. Emission Inventory

To determine maximum potential emissions, PTE calculations considered the two maximum operating scenarios:

- Simple cycle operation for permit limit of 3,200 hours per turbine per year; combined cycle operation for balance of year (i.e., 5,560 hours per turbine per year).
- No simple cycle operation; combined cycle operation for 8,760 hours per turbine per year.

Then, results from the two scenarios were compared and the highest result for each pollutant was selected as the PTE. For simple cycle operation, SUSD emission factors were used because there are no limits on the number of startup/shutdown cycles. Simple cycle SUSD factors are equal to or higher than the steady state factors and thus represent a worst-case scenario. For combined cycle operation, permit conditions limit startup to 1,460 hours per unit per year, and shutdown to 730 hours per unit per year; therefore, the SUSD emission factors are used for the respective annual hour limits and the steady state emission factor is used for the balance of the year.

Table IV. Annual Emissions

Source	**Annual Emissions (TPY)**						
	PM	**PM_{10}**	**$PM_{2.5}$**	**NO_x**	**CO**	**VOC**	**SO_2**
Turbine East	31.54	31.54	31.54	89.11	244.08	11.41	3.02
Turbine West	31.54	31.54	31.54	89.11	244.08	11.41	3.02
Emergency Generator	0.04	0.04	0.04	6.04	0.55	0.13	0.09
Fire Pump Engine	0.04	0.04	0.04	1.02	0.24	0.04	0.02
Cooling Towers	1.14	1.14	1.14	--	--	--	--
Building Heaters	0.09	0.09	0.09	1.68	1.01	0.07	0.01
Haul Roads	5.68	1.57	--	--	--	--	--
Total	**70.07**	**65.96**	**64.39**	**186.96**	**489.96**	**23.06**	**6.16**

Combustion Turbines

$PM/PM_{10}/PM_{2.5}$ Emissions

Note: The highest $PM/PM_{10}/PM_{2.5}$ emissions occur when both turbines operate in combined cycle only, 8,760 hours per turbine per year (startup 1,460 hr/turbine/yr, shutdown 730 hr/turbine/yr, steady state 6,570 hr/turbine/yr).

Simple Cycle Operation (per turbine): 0 hr/turbine/yr (Permit limit, including startup and shutdown)
Simple Cycle Emission Factor = 4.8 lb/hr (BACT limit, maximum)
Calculation: (2 turbines) * (0 hr/turbine/yr) * (4.8 lb/hr) * (1 ton/ 2000 lb) = 0.00 tons/yr

Combined Cycle Startup (per turbine): 1,460 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Startup Emission Factor = 7.2 lb/hr (BACT limit, startup)
Calculation: (2 turbines) * (1460 hr/turbine/yr) * (7.2 lb/hr) * (1 ton/ 2000 lb) = 10.51 tons/yr

Combined Cycle Shutdown (per turbine): 730 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Shutdown Emission Factor = 7.2 lb/hr (BACT limit, shutdown)
Calculation: (2 turbines) * (730 hr/turbine/yr) * (7.2 lb/hr) * (1 ton/ 2000 lb) = 5.26 tons/yr

Combined Cycle Steady State (per turbine): 6,570 hr/turbine/yr
Combined Cycle Steady State Emission Factor = 7.2 lb/hr (BACT limit, steady state)
Calculation: (2 turbines) * (6570 hr/turbine/yr) * (7.2 lb/hr) * (1 ton/ 2000 lb) = 47.30 tons/yr

Total $PM/PM_{10}/PM_{2.5}$ Emissions = 63.07 tons/yr

<u>NO_x Emissions</u>

Note: The highest NO_x emissions occur when both turbines operate in simple cycle for 3,200 hours per turbine per year, and the balance of the year in combined cycle (startup 1,460 hr/turbine/yr, shutdown 730 hr/turbine/yr, steady state 3,370 hr/turbine/yr).

Simple Cycle Operation (per turbine): 3,200 hr/turbine/yr (Permit limit, including startup and shutdown)
Simple Cycle Emission Factor = 36.58 lb/hr (BACT limit, maximum)
Calculation: (2 turbines) * (3200 hr/turbine/yr) * (36.58 lb/hr) * (1 ton/ 2000 lb) = 117.06 tons/yr

Combined Cycle Startup (per turbine): 1,460 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Startup Emission Factor = 26.12 lb/hr (BACT limit, startup)
Calculation: (2 turbines) * (1460 hr/turbine/yr) * (26.12 lb/hr) * (1 ton/ 2000 lb) = 38.14 tons/yr

Combined Cycle Shutdown (per turbine): 730 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Shutdown Emission Factor = 12.33 lb/hr (BACT limit, shutdown)
Calculation: (2 turbines) * (730 hr/turbine/yr) * (12.33 lb/hr) * (1 ton/ 2000 lb) = 9.00 tons/yr

Combined Cycle Steady State (per turbine): 3,370 hr/turbine/yr
Combined Cycle Steady State Emission Factor = 4.16 lb/hr (BACT limit, steady state)
Calculation: (2 turbines) * (3370 hr/turbine/yr) * (4.16 lb/hr) * (1 ton/ 2000 lb) = 14.02 tons/yr

Total NO_x Emissions = 178.21 tons/yr

<u>CO Emissions</u>

Note: The highest CO emissions occur when both turbines operate in simple cycle for 3,200 hours per turbine per year, and the balance of the year in combined cycle (startup 1,460 hr/turbine/yr, shutdown 730 hr/turbine/yr, steady state 3,370 hr/turbine/yr).

Simple Cycle Operation (per turbine): 3,200 hr/turbine/yr (Permit limit, including startup and shutdown)
Simple Cycle Emission Factor = 114.7 lb/hr (BACT limit, maximum)
Calculation: (2 turbines) * (3200 hr/turbine/yr) * (114.7 lb/hr) * (1 ton/ 2000 lb) = 367.04 tons/yr

Combined Cycle Startup (per turbine): 1,460 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Startup Emission Factor = 76.2 lb/hr (BACT limit, startup)
Calculation: (2 turbines) * (1460 hr/turbine/yr) * (76.2 lb/hr) * (1 ton/ 2000 lb) = 111.25 tons/yr

Combined Cycle Shutdown (per turbine): 730 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Shutdown Emission Factor = 4.15 lb/hr (BACT limit, shutdown)
Calculation: (2 turbines) * (730 hr/turbine/yr) * (4.15 lb/hr) * (1 ton/ 2000 lb) = 3.03 tons/yr

Combined Cycle Steady State (per turbine): 3,370 hr/turbine/yr
Combined Cycle Steady State Emission Factor = 2.03 lb/hr (BACT limit, steady state)
Calculation: (2 turbines) * (3370 hr/turbine/yr) * (2.03 lb/hr) * (1 ton/ 2000 lb) = 6.84 tons/yr

Total CO Emissions = 488.16 tons/yr

VOC Emissions

Note: The highest VOC emissions occur when both turbines operate in simple cycle for 3,200 hours per turbine per year, and the balance of the year in combined cycle (startup 1,460 hr/turbine/yr, shutdown 730 hr/turbine/yr, steady state 3,370 hr/turbine/yr).

Simple Cycle Operation (per turbine): 3,200 hr/turbine/yr (Permit limit, including startup and shutdown)
Simple Cycle Emission Factor = 3.9 lb/hr (BACT limit, maximum)
Calculation: (2 turbines) * (3200 hr/turbine/yr) * (3.9 lb/hr) * (1 ton/ 2000 lb) = 12.48 tons/yr

Combined Cycle Startup (per turbine): 1,460 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Startup Emission Factor = 1.86 lb/hr (BACT limit, startup)
Calculation: (2 turbines) * (1460 hr/turbine/yr) * (1.86 lb/hr) * (1 ton/ 2000 lb) = 2.72 tons/yr

Combined Cycle Shutdown (per turbine): 730 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Shutdown Emission Factor = 1.86 lb/hr (BACT limit, shutdown)
Calculation: (2 turbines) * (730 hr/turbine/yr) * (1.86 lb/hr) * (1 ton/ 2000 lb) = 1.36 tons/yr

Combined Cycle Steady State (per turbine): 3,370 hr/turbine/yr
Combined Cycle Steady State Emission Factor = 1.86 lb/hr (BACT limit, steady state)
Calculation: (2 turbines) * (3370 hr/turbine/yr) * (1.86 lb/hr) * (1 ton/ 2000 lb) = 6.27 tons/yr

Total VOC Emissions = 22.82 tons/yr

SO_2 Emissions

Note: The highest SO_2 emissions occur when both turbines operate in combined cycle only, 8,760 hours per turbine per year (startup 1,460 hr/turbine/yr, shutdown 730 hr/turbine/yr, steady state 6,570 hr/turbine/yr).

Simple Cycle Operation (per turbine): 0 hr/turbine/yr (Permit limit, including startup and shutdown)
Simple Cycle Emission Factor = 0.57 lb/hr (BACT limit, maximum)
Calculation: (2 turbines) * (0 hr/turbine/yr) * (0.57 lb/hr) * (1 ton/ 2000 lb) = 0.00 tons/yr

Combined Cycle Startup (per turbine): 1,460 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Startup Emission Factor = 0.69 lb/hr (BACT limit, startup)
Calculation: (2 turbines) * (1460 hr/turbine/yr) * (0.69 lb/hr) * (1 ton/ 2000 lb) = 1.01 tons/yr

Combined Cycle Shutdown (per turbine): 730 hr/turbine/yr (Permit limit, based on two SUSD cycles per day)
Combined Cycle Shutdown Emission Factor = 0.69 lb/hr (BACT limit, shutdown)
Calculation: (2 turbines) * (730 hr/turbine/yr) * (0.69 lb/hr) * (1 ton/ 2000 lb) = 0.50 tons/yr

Combined Cycle Steady State (per turbine): 6,570 hr/turbine/yr
Combined Cycle Steady State Emission Factor = 0.69 lb/hr (BACT limit, steady state)
Calculation: (2 turbines) * (6570 hr/turbine/yr) * (0.69 lb/hr) * (1 ton/ 2000 lb) = 4.53 tons/yr

Total SO_2 Emissions = 6.04 tons/yr

Emergency Diesel Generator

Note: Emissions are based on the power output of the engine (i.e., shaft power, or "brake horsepower", bhp), not the generator output.
Generator Output = 1,500 kW (2,011 hp) (vendor data)
Engine Output = 2,206 bhp (vendor data)
Hours of Operation = 500 hr/yr (Permit limit)

$PM/PM_{10}/PM_{2.5}$ Emissions

Assume vendor data represents total filterable particulate. According to AP-42, Table 3.4-2 (10/96), the ratio of total $PM_{2.5}$ (filterable $PM_{2.5}$ plus all condensable particulate) to total filterable particulate is 0.897; i.e., total $PM_{2.5}$ is approximately 90% of the total filterable particulate. Thus, estimation of $PM_{2.5}$ is conservative since it is approximately 90% of vendor value.

Emission Factor = 0.03 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (2,206 bhp) * (0.03 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.04 tons/yr

NO_x Emissions

Emission Factor = 4.97 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (2,206 bhp) * (4.97 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 6.04 tons/yr

CO Emissions

Emission Factor = 0.45 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (2,206 bhp) * (0.45 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.55 tons/yr

VOC Emissions

Emission Factor = 0.11 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (2,206 bhp) * (0.11 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.13 tons/yr

SO_2 Emissions

Assume all fuel sulfur is converted to SO_x.
Diesel Fuel Sulfur Content = 500 ppm = (500/1,000,000) = 0.0005 (sulfur limit, nonroad diesel fuel, 40 CFR 80.510)
Fuel Flow at 100% Load = 104.8 gal/hr (vendor data)
Diesel Density = 7.001 lb/gal (vendor data)
Sulfur content = 0.0005 * (7.001 lb/gal) = 0.0035005 lb/gal
Calculation: (500 hr/yr) * (104.8 gal/hr) * (0.0035005 lb/gal) * (ton/2000 lb) = 0.09 tons/yr

Fire Pump Engine

Note: Emissions are based on the power output of the engine (i.e., shaft power, or "brake horsepower", bhp), not pump power output.
Engine Output = 343 bhp (vendor data)
Hours of Operation = 500 hr/yr (Permit limit)

$PM/PM_{10}/PM_{2.5}$ Emissions

Assume vendor data represents total filterable particulate. According to AP-42, Table 3.4-2 (10/96), the ratio of total $PM_{2.5}$ (filterable $PM_{2.5}$ plus all condensable particulate) to total filterable particulate is 0.897; i.e., total $PM_{2.5}$ is approximately 90% of the total filterable particulate. Thus, estimation of $PM_{2.5}$ is conservative since it is approximately 90% of vendor value.

Emission Factor = 0.211 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (343 bhp) * (0.211 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.04 tons/yr

NO_x Emissions

Emission Factor = 5.41 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (343 bhp) * (5.41 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 1.02 tons/yr

CO Emissions

Emission Factor = 1.25 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (343 bhp) * (1.25 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.24 tons/yr

VOC Emissions
Emission Factor = 0.2 g/hp-hr (vendor data)
Calculation: (500 hr/yr) * (343 bhp) * (0.2 g/hp-hr) * (lb /453.59 g) * (ton/2000 lb) = 0.04 tons/yr

SO_2 Emissions

Assume all fuel sulfur is converted to SOx.
Diesel Fuel Sulfur Content = 500 ppm = (500/1,000,000) = 0.0005 (sulfur limit, nonroad diesel fuel, 40 CFR 80.510)
Fuel Flow at 100% Load = 17.9 gal/hr (vendor data)
Diesel Density = 7 lb/gal
Sulfur content = 0.0005 * (7 lb/gal) = 0.0035 lb/gal
Calculation: (500 hr/yr) * (17.9 gal/hr) * (0.0035 lb/gal) * (ton/2000 lb) = 0.02 tons/yr

Cooling Towers

Circulating Flow: 28,000 gal/min (Based on analysis by Bison and Stanley Consultants)

Drift %: 0.002 % (estimate) (Drift is "shedding" of water droplets from the mist eliminators in the cooling towers that are ejected into the water vapor stream. As they are water droplets, and not vapor, they can carry minute amounts of minerals, which then become airborne particulate after the water droplet evaporates downrange. The evaporate from the cooling towers is just vapor, and therefore does not become particulate.)

Drift Flow = 28,000 gal/min * 0.002/100 = 0.56 gal/min

Number of Concentration Cycles: 5 ("Concentration cycles" are the number of times that steam/water can cycle before mineral content exceeds the threshold for boiler operation capacity due to evaporative losses. When the saturated steam from the turbine is recirculated to the cooling towers, a portion of the water evaporates which removes the energy from the steam, causing it condense back to liquid. The evaporated portion is added back to the cycle as demineralized make-up water, with the specified amount of minerals in solution. However, the evaporated water leaves behind mineral content. After so many "concentration cycles," the mineral content builds and eventually exceeds the thresholds of boiler quality demineralized make-up water, and then must be flushed out of the system. The make-up water cannot be circulated indefinitely.)

Dissolved Solids Concentration: 186 mg/liter (Based on analysis by Bison and Stanley Consultants)

$PM/PM_{10}/PM_{2.5}$ Emissions

Calculation: (0.56 gal/min) * (3.7854 liters/gal) * (186 mg/liter) * (5 cycles) = 1,971.44 mg/min
Conversion: (1,971.44 mg/min) * (lb/ 453592.37 mg) * (1 ton/ 2000 lb) * (60 min/ hr) * (8,760 hr/ yr) = 1.14 tons/yr

Building Heaters

Heat Rate of Buildings:
- Turbine Enclosures = 0.25 MMBtu/hr
- Admin/Maintenance/Electrical/STG Building = 1.00 MMBtu/hr
- Water Treatment Building = 0.50 MMBtu/hr
- Warehouse = 0.50 MMBtu/hr
- Water Pumphouse = 0.25 MMBtu/hr
- Fuel Gas Compressor Building = 0.25 MMBtu/hr
- CEMS Enclosures (2ea) = 0.05 MMBtu/hr

Total = 2.80 MMBtu/hr

Average natural gas higher heating value = 1,020 Btu/scf (AP-42, Table 1.4-1, 7/98)

$PM/PM_{10}/PM_{2.5}$ Emissions

Emission Factor = 7.6 lb/ 10^6 scf (AP-42, Table 1.4-2, 7/98)
Calculation: (8,760 hrs/yr) * (2.8 MMBtu/hr) * (1 / 1020 Btu/scf) * (7.6 lb/ 10^6 scf) * (ton/2000 lb) = 0.09 tons/yr

NO_x Emissions

Emission Factor = 140 lb/10^6 scf (AP-42, Table 1.4-1, 7/98)
Calculation: (8,760 hrs/yr) * (2.8 MMBtu/hr) * (1 / 1020 Btu/scf) * (140 lb/10^6 scf) * (ton/2000 lb) = 1.68 tons/yr

CO Emissions

Emission Factor = 84 lb/10^6 scf (AP-42, Table 1.4-1, 7/98)
Calculation: (8,760 hrs/yr) * (2.8 MMBtu/hr) * (1 / 1020 Btu/scf) * (84 lb/10^6 scf) * (ton/2000 lb) = 1.01 tons/yr

VOC Emissions

Emission Factor = 5.5 lb/10^6 scf (AP-42, Table 1.4-2, 7/98)
Calculation: (8,760 hrs/yr) * (2.8 MMBtu/hr) * (1 / 1020 Btu/scf) * (5.5 lb/10^6 scf) * (ton/2000 lb) = 0.07 tons/yr

SO_2 Emissions

Emission Factor = 0.6 lb/10^6 scf (AP-42, Table 1.4-2, 7/98)
Calculation: (8,760 hrs/yr) * (2.8 MMBtu/hr) * (1 / 1020 Btu/scf) * (0.6 lb/10^6 scf) * (ton/2000 lb) = 0.01 tons/yr

Haul Roads

Vehicle Miles Traveled (VMT) per Day = 5 VMT/day (Estimate)
VMT per hour = (5 VMT/day) * (day/24 hrs) = 0.21 VMT/hr
Hours of Operation = 8,760 hrs/yr

PM Emissions

Predictive equation for emission factor for unpaved roads at industrial sites provided per AP 42, Ch. 13.2.2, 11/06.
Emission Factor = $k * (s / 12)^a * (W / 3)^b$ = 12.46 lb/VMT
Where: k = constant = 4.9 lbs/VMT (Value for PM30/TSP, AP 42, Table 13.2.2-2, 11/06)
s = surface silt content = 7.1 % (Mean value, sand/gravel processing, material storage area, AP 42, Table 13.2.2-1, 11/06)
W = mean vehicle weight = 54 tons (1994 average loaded/unloaded or a 40 ton truck)
a = constant = 0.7 (Value for PM_{30}/TSP, AP 42, Table 13.2.2-2, 11/06)
b = constant = 0.45 (Value for PM_{30}/TSP, AP 42, Table 13.2.2-2, 11/06)
Control Efficiency = 50% (Water spray or chemical dust suppressant)
Calculation: (8760 hrs/yr) * (0.21 VMT/hr) * (12.46 lb/VMT) * (ton/2000 lb) * (1-50/100) = 5.68 tons/yr

PM_{10} Emissions

Predictive equation for emission factor for unpaved roads at industrial sites provided per AP 42, Ch. 13.2.2, 11/06.
Emission Factor = $k * (s / 12)^a * (W / 3)^b$ = 3.43 lb/VMT
Where: k = constant = 1.5 lbs/VMT (Value for PM10, AP 42, Table 13.2.2-2, 11/06)
s = surface silt content = 7.1 % (Mean value, sand/gravel processing, material storage area, AP 42, Table 13.2.2-1, 11/06)
W = mean vehicle weight = 54 tons (1994 average loaded/unloaded or a 40 ton truck)
a = constant = 0.9 (Value for PM_{10}, AP 42, Table 13.2.2-2, 11/06)
b = constant = 0.45 (Value for PM_{10}, AP 42, Table 13.2.2-2, 11/06)
Control Efficiency = 50% (Water spray or chemical dust suppressant)
Calculation: (8760 hrs/yr) * (0.21 VMT/hr) * (3.43 lb/VMT) * (ton/2000 lb) * (1-50/100) = 1.57 tons/yr

V. Existing Air Quality

The proposed turbine generator facility will be located approximately 8 miles northeast of Great Falls, Cascade County, and is southeast about 2.4 km (1.5 miles) from the Morony Dam on the Missouri River. The total footprint of the turbine generator facility will be approximately six acres. The legal description of the property is Sections 24, and 25, Township 21 North, Range 5 East, Cascade County.

The air quality classification of the project area is "Unclassifiable/Attainment" for all air quality criteria pollutants (40 CFR 81.327). A narrow area of Great Falls along 10th Avenue South (bounded by 9th Avenue South on the north, 11th Avenue South on the south, 54th Street South on the east, and 2nd Street South on the west) was classified as a carbon monoxide nonattainment area, but was redesignated attainment on July 8, 2002 (noticed in the May 9, 2002 (67 Federal Register 31143)).

VI. Ambient Air Impact Analysis

As part of Permit Application #4429-00, SME submitted a modeling analysis of ambient air quality dispersion. Bison provided the modeling demonstrations on behalf of SME. When SME submitted the modeling demonstration, the SME property upon which the HGS gas plant is to be constructed was also permitted for the HGS coal plant (MAQP #3423-01). The modeling demonstration that SME submitted for the HGS gas plant analyzed combined worst case emissions from both the HGS coal plant and the HGS gas plant as if emissions from each facility were to occur simultaneously. This worst case analysis demonstrated compliance with Montana Ambient Air Quality Standards (MAAQS), National Ambient Air Quality Standards (NAAQS), and PSD Class II and Class I increments.

Following submission of the HGS gas plant application and modeling demonstration, SME requested that the Department revoke MAQP #3423-01 for the HGS coal plant. Revocation of MAQP #3423-01 became final on August 20, 2009.

The Department has determined that a modeling demonstration specific to the HGS gas plant alone is not required because the combined coal plant / gas plant modeling analysis was highly conservative, yet still demonstrated compliance with all applicable standards. Therefore, the Department is relying on this combined analysis for the HGS gas plant. A summary of the SME analysis for the HGS coal and gas plants follows. The full Department modeling analysis memorandum is available on file with the Department.

A. Project Summary

On June 11, 2009, SME submitted a final modeling demonstration for application MAQP #4429-00 to construct, operate, and maintain two natural gas turbine electric generating units at the HGS gas plant. The HGS gas plant will be composed of two natural gas turbine electric generating units with a combined net output of approximately 120 MW. The turbines will operate in either Simple Cycle (no heat recovery) or Combined Cycle (with heat recovery).

The HGS coal plant previously permitted under MAQP #3423-01 was a New Source Review PSD listed source because it met the definition of a fossil-fuel fired steam-electric generating plant with more than 250 MMBtu/hr heat input capacity. Furthermore, the HGS coal plant emissions of PM, PM_{10}, NO_x, SO_2, and CO were estimated to be greater than 100 tons per year; therefore, the facility was considered a major source under the PSD program (ARM 17.8.818). This source triggered the minor baseline date for SO_2 on May 16, 2006. The minor PSD source baseline dates have been triggered in the area for NO_x and PM_{10} by the following industries:

- Montana Refining Company - NO_x 02/22/93
- AgriTechnology Montana LLC - PM_{10} 08/30/01 (the Montana Ethanol Project, LLC is the current corporation name for AgriTechnology Montana LLC)

Prior to the revocation of MAQP #3423-01, the Department considered the application for MAQP #4429-00 as a major modification under PSD to the HGS coal plant (MAQP #3423-00 and MAQP #3423-01). The HGS coal plant and gas plant facilities were assigned different permit numbers for administrative reasons, and to simplify the public and agency review of the natural gas plant permit. Subsequent to the revocation of MAQP #3423-01, the HGS gas plant remains a major stationary source with respect to PSD because it is a PSD-listed source (i.e., a fossil-fuel fired steam-electric generating plant with more than 250 MMBtu/hr heat input capacity) for which emissions of any regulated pollutant are 100 TPY or greater.

The modeling demonstration included both NAAQS/MAAQS analyses and a Class II PSD increment analysis. All of the HGS coal plant emissions were included in these modeling analyses although the MAQP #4429-00 was to prohibit the operation of the boiler while the HGS gas plant operates. Therefore, these results represented very conservative estimates. For clarification, the HGS coal plant sources were not included in the significant impact analysis that established the maximum radius of impact from the HGS gas plant potential emissions. Bison included the Cooling Towers, Fire Pump, and Back Start Generator from the HGS coal plant in the HGS gas plant analysis, stating that these units would be common to both the coal and gas plant.

Impacts were evaluated at the following federal Class I areas (approximate distances from the SME property in parenthesis): Bob Marshall Wilderness Area (134 kilometers, km), Gates of the Mountains Wilderness Area (88 km), Glacier National Park (192 km), Scapegoat Wilderness Area (122 km), and UL Bend Wilderness Area (222 km). The Federal Land Managers recommends an impact analysis completed for Class I areas within 100 km of the source. The above Class I areas meet this recommendation and exceed it in some cases. The Class I modeling assessed the Class I PSD increment consumption, visibility degradation, and deposition (nitrogen and sulfur) effects.

Table VI.A.1 lists the maximum HGS gas plant emissions for the following air pollutants: PM, NO_x, SO_2, CO, VOC, and lead (Pb).

Table VI.A.1. HGS Gas Plant Maximum Potential Annual Emissions.

Description	HGS Gas Plant Emissions (tpy)					
	$PM_{10}/PM_{2.5}$	NO_x	SO_2	CO	VOC	Pb
Turbines	63.10	178.21	6.05	488.14	22.83	NA[2]
Cooling Towers	1.14	NA	NA	NA	NA	NA
Fire Pump [a]	0.04	0.92	0.02	0.21	0.03	NA
Black Start Generator	0.04	6.04	0.09	0.55	0.13	NA
Building Heaters	0.09	1.68	0.01	1.01	0.07	NA
Total [b]	64.41	186.86	6.16	489.91	23.07	NA

a. Fire pump values are slightly lower than values in Section IV because anticipated fire pump horsepower was adjusted after modeling demonstration was completed. Impact of difference anticipated to be insignificant.
b. Totals may vary due to rounding conventions.

As the previous table indicates, the HGS gas plant annual emissions exceeded the 100 TPY listed-source PSD thresholds for NO_x and CO. The facility also exceeds significance thresholds for PM (25 TPY) and PM_{10} (15 TPY). Therefore, modeling was required for NO_x, CO, $PM_{10}/PM_{2.5}$.

Table VI.A.2 lists the maximum annual and hourly emission rates for the HGS gas plant individual sources used in the modeling analyses. Both steady state (SS) and SUSD emissions were calculated. There will be two stacks each for both Simple Cycle (SC) and Combined Cycle (CC) Turbines, which were defined directionally as West and East, for a total of four modeled stacks. All emissions were calculated using 8,760 hours per year (hr/yr), except for the Fire Pump and Black Start Generator, which will be limited to 500 hr/yr. In Simple Cycle mode, the turbines will be limited to 3,200 hr/yr.

Table VI.A.2. HGS Gas Plant Individual Source Maximum Modeled Annual and Hourly Emissions.

Source	HGS Gas Plant Emissions						
	$PM_{10}/PM_{2.5}$ (tpy)	$PM_{10}/PM_{2.5}$ (lb/hr)	NO_x (tpy)	NO_x (lb/hr)	SO_2 (tpy)	SO_2 (lb/hr)	CO (lb/hr)
SC SS West	21.02	4.80	160.22	36.58	2.50	0.57	48.96
SC SS East	21.02	4.80	160.22	36.58	2.50	0.57	48.96
CC SS West	31.54	7.20	18.22	4.16	3.02	0.69	2.03
CC SS East	31.54	7.20	18.22	4.16	3.02	0.69	2.03
SC SUSD West	21.02	4.80	160.22	36.58	2.50	0.57	114.70
SC SUSD East	21.02	4.80	160.22	36.58	2.50	0.57	114.70
CC SUSD West	31.54	7.20	114.41	26.12	3.02	0.69	76.20
CC SUSD East	31.54	7.20	114.41	26.12	3.02	0.69	76.20
Cooling Tower	1.03	0.235	NA	NA	NA	NA	NA
Cooling Tower	1.03	0.235	NA	NA	NA	NA	NA
Cooling Tower	1.03	0.235	NA	NA	NA	NA	NA
Fire Pump	0.036	0.140	0.920	3.680	0.016	0.060	0.850
Back Start Generator	0.040	0.150	6.040	24.200	0.180	0.370	2.200
Turbine Enclosure West	8.20E-03	2.00E-03	1.49E-01	3.40E-02	6.57E-04	1.50E-04	2.10E-02
Turbine Enclosure East	8.76E-03	2.00E-03	1.49E-01	3.40E-02	6.57E-04	1.50E-04	2.10E-02
Admin/Maint/Elec/ STG Bldg	3.26E-02	7.44E-03	6.00E-01	1.37E-01	2.58E-03	5.90E-04	8.20E-02
Water Treatment Bldg	1.75E-02	4.00E-03	3.02E-01	6.90E-02	1.27E-03	2.90E-04	4.10E-02
Warehouse	1.75E-02	4.00E-03	3.02E-01	6.90E-02	1.27E-03	2.90E-04	4.10E-02
Water Pump House	8.76E-03	2.00E-03	1.49E-01	3.40E-02	6.57E-04	1.50E-04	2.10E-02
Fuel Gas Compressor Bldg	8.76E-03	2.00E-03	1.49E-01	3.40E-02	6.57E-04	1.50E-04	2.10E-02
CEMS Enclosures	1.75E-03	4.00E-04	3.07E-02	7.00E-03	1.31E-04	3.00E-05	4.00E-03

B. Class II Area Modeling Parameters

SME followed the U.S. EPA guidance [1], the New Source Review Workshop Manual [2],and the Draft MDEQ Modeling Guidance for Air Quality Permit Applications (MDEQ Modeling Guidance).

C. Review of AERMOD Model Inputs

AERMOD Modeling System: SME used the Bee-Line Software BEEST for Windows (Version 9.78a). The AERMOD modeling system included AERMOD PRIME (Version 07026), AERMET (Version 06341), and AERMAP (Version 09040). The AERMOD modeling system was used in the regulatory default mode. No wet or dry depletion was assumed.

[1] United States Environmental Protection Agency (USEPA). 2005. "Guideline on Air Quality Models." 40 CFR Part 51. Appendix W. November 2005.

[2] USEPA. 1990. "New Source Review Workshop Manual Prevention of Significant Deterioration and Nonattainment Area Permitting Draft." October 1990. [Online]. Available: http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

Terrain: The elevations of the NG HGS emission sources and buildings were determined from the plant layout drawings. The plant layout drawing that the Department received did not contain any elevation information. The BEEST modeling software "Calc Domain" function was used to determine the modeling domain extent and to identify the United States Geological Survey (USGS) digital elevation model (DEM) files required by AERMAP terrain preprocessor. This program calculated the receptor (and hill height) elevations. The DEMs were USGS 7.5 minute (1:24,000 scale) North American Datum 1927 (NAD27). All of these files had 30 meter resolution square grid resolution.

Land Use: The Department classifies all of Montana as rural so the rural dispersion coefficients were selected.

Receptors: For the significant impact analysis (SIA), a total of 13,627 receptors were used. Receptors were placed along the facility fenceline at no more than 100 meter (m) spacings.

Meteorology: Five years of meteorological (met) data (1999 - 2003) were used. The surface and upper met data were obtained for Great Falls International Airport National Weather Service, Montana (station #24143). This airport is approximately 10 km (6.4 miles) southwest of the site. No missing surface met data was substituted. The profile base elevation was 1,117.1 m (3,665 feet) and the anemometer height was 6.7 m (22 feet). According to WebMet website (http://www.webmet.com/State_pages/met_mt.htm), the airport latitude and longitude were 47.473N and 111.382W, North American Datum 1983 (NAD83).

AERSURFACE: SME used AERSURFACE (Version 08009) to develop the surface characteristics for the Great Falls International Airport met station for input into AERMET. The USGS National Land Cover Data 1992 archives were used to determine the land cover types for this met station. Seasonal surface characteristics were determined for 36 ten-degree sectors. SME used the AERSURFACE options recommended by the Department.

Building Downwash: The USEPA-developed Building Profile Input Program – Plume Rise Model Enhancement (BPIP-PRIME) included with the BEEST AERMOD modeling platform was used for building downwash. On the entire SME site including the ones associated with the coal plant, ninety-one (91) structures and fourteen (14) tanks were modeled for downwash for a total of one hundred and five (105) structures.

An additional forty-two (42) buildings and three (3) tanks were also included from the off-site facilities.

HGS Gas Plant Point Source Parameters: Eight out of the twenty-one (21) modeled point emission sources involved the four main stacks. They were treated as separate emission sources since the operation of the turbines (steady state and startup/shutdown) affected the gas exit velocities and temperatures. The modeled point source parameters are listed in Table VI.C.3.

Table VI.C.3. Modeled HGS Gas Plant Point Source Parameters.

Source ID	Description	UTM NAD27 Zone 12		Elevation (m)	Stack Height (m)	Stack Inside Diameter (m)	Stack Gas Exit Temperature (Kelvin)	Stack Gas Exit Velocity (m/sec)
		meters Easting	meters Northing					
HI_SCW	SC SS West	497423	5266224	1008.9	24.38	3.51	735.93	41.67
HI_SCE	SC SS East	497460	5266224	1008.9	24.38	3.51	735.93	41.67
HI_CCW	CS SS West	497422	5266262	1008.9	32.00	3.05	379.26	20.24
HI_CCE	CS SS East	497460	5266262	1008.9	32.00	3.05	379.26	20.24
SS_SCE	SC SUSD[3] West	497423	5266224	1008.9	24.38	3.51	735.93	41.67
SS_SCW	SC SUSD East	497460	5266224	1008.9	24.38	3.51	735.93	41.67
SS_CCW	CC SUSD West	497422	5266262	1008.9	32.00	3.05	379.26	20.24
SS_CCE	CC SUSD East	497460	5266262	1008.9	32.00	3.05	379.26	20.24
COOLING1	Cooling Tower	497495	5266449	1008.9	13.72	4.57	294.26	8.23
COOLING2	Cooling Tower	497507	5266460	1008.9	13.72	4.57	294.26	8.23
COOLING3	Cooling Tower	497518	5266472	1008.9	13.72	4.57	294.26	8.23
FIREP	Fire Pump	497382	5266296	1008.9	7.62	0.15	828.71	53.17
GENSET	Back Start Generator	497402	5266248	1008.9	10.67	0.38	679.54	45.78
HEATTW	Turbine Enclosure West	497422	5266213	1008.9	13.72	0.15	560.93	25.87
HEATTE	Turbine Enclosure East	497459	5266213	1008.9	13.72	0.15	560.93	25.87
HEATAD	Admin/Maint/Elec/STG Bldg	497380	5266237	1008.9	21.34	0.31	560.93	25.87
HEATWT	Water Treatment Bldg	497373	5266323	1008.9	9.14	0.31	560.93	12.94
HEATWH	Warehouse	497307	5266184	1008.9	9.14	0.31	560.93	12.94
HEATWP	Water Pump House	497495	5266426	1008.9	6.40	0.15	560.93	25.87
HEATCB	Fuel Gas Compressor Bldg	497407	5266386	1008.9	6.10	0.15	560.93	25.87
HEATCE	CEMS Enclosures	497443	5266229	1008.9	4.57	0.15	560.93	5.17

D. Class II Area Modeling Results

Significant Impact Areas: The HGS gas plant facility emissions were modeled to determine concentrations (micrograms per cubic meter, $\mu g/m^3$) and the SIAs for each relevant pollutant and averaging period as displayed in Table VI.D.1. The SIA modeling used the individual met years to determine the high-first-high (H1H) concentrations. No background concentrations were added. At this time, no current $PM_{2.5}$ significance level exists; however, SME selected the most conservative significant impact option proposed by the USEPA. [3] To simplify the PM SIA modeling analyses, one model run was performed with each met year since it was assumed that $PM_{2.5}$ equaled PM_{10} emissions.

Table VI.D.1. Significance Impact Levels and SIAs.

Pollutant	Averaging Period	Significance Level ($\mu g/m^3$)	Met Year	Modeled Concentration ($\mu g/m^3$)	Source Group	SIA Radii (km)	Significant Impact?
$PM_{2.5}$	24-Hour	1.2	2002	6.83	CC_SS	2.7	YES
	Annual	0.3	1999	0.79	CC_SS	1.1	YES
PM_{10}	24-Hour	5	2002	6.83	CC_SS	0.5	YES
	Annual	1	1999	0.79	CC_SS	0.0	NO
NO_x	Annual	1	1999	3.50	CC_SS	1.2	YES
SO_2	1-Hour	25	2000	7.9	ALL GROUPS	0.0	NO
	3-Hour	25	2003	5.18	ALL GROUPS	0.0	NO
	24-Hour	5	2003	2.07	CC_SS, 4SCE_CCW SS_SCE	0.0	NO
	Annual	1	1999	0.09	CC_SS	0.0	NO
CO	1-Hour	2,000	2003	328.60	CC_SS	0.0	NO
	8-Hour	500	2002	112.53	4SCE_CCW, SS_SCE	0.0	NO

As shown in Table VI.D.1, further modeling analysis was not necessary for SO_2 and CO since these pollutants did not exceed their corresponding significance levels. The maximum radius was 2.7 km from the 24-hour $PM_{2.5}$ HSG gas plant emissions.

Off-Site Facility Emission Sources: The following seven off-site facilities were included in the NAAQS/MAAQS, and Class II PSD increment modeling analyses. This list also includes their corresponding latest MAQP number.

- CHS Incorporated (previously, Land O'Lakes/Harvest States Feed) – MAQP #2842-01
- Malmstrom Air Force Base – MAQP #1427-08
- Malteurop North America – MAQP #3238-04 (Facility not constructed)
- Montana Ethanol Project, LLC. - MAQP #2835-06 (Facility not constructed)
- Montana Refining Company – MAQP #2161-21
- Montana Waste Systems – Operating Permit #OP2981-02
- Montgomery Great Falls Energy Partners LP – MAQP #3154-05 [4] (Facility not constructed)

[3] USEPA. 2007. 40 CFR Parts 51 and 52 [EPA-HQ-OAR-2006-0605; FRL-8470-1] RIN 2060-AO24 "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)." September 21, 2007. [Online]. Available: http://www.epa.gov/EPA-AIR/2007/September/Day-21/a18346.pdf.

[4] MAQP #3154-06 became final on August 7, 2009, after the HGS gas plant permit modeling analyses were completed. The emissions inventory in MAQP #3154-06 differed slightly from MAQP #3154-05, but are not anticipated to have any significant impact on the HGS gas plant air quality modeling analysis.

To reiterate, the HGS coal plant emissions (MAQP #3423-01) were included in the near-field modeling analyses, although MAQP #4429-00 was to have enforceable measures to ensure that the CFB stack and natural gas turbines did not operate concurrently previous to the revocation of MAQP #3423-01.

E. NAAQS/MAAQS Analyses

The $PM_{2.5}$, PM_{10}, and NO_x NAAQS/MAAQS analyses used the maximum emission rates from the HGS plants and all of the off-site facilities; the results are shown in Table VI.E.1. The same eight source groups (Table VI.C.4) were used as in the significance analysis with all of the off-site emissions added to each group.

For comparison to the hourly standards, the high-second-high (H2H) concentrations were selected (based on EPA guidance and the wording of the specific pollutant standards). For comparison to the daily standards, the high-first-high (H2H) concentrations were chosen, except for $PM_{2.5}$. For the 24-hour $PM_{2.5}$, the highest-eighth-high (H8H) modeled concentration was selected. For the annual averaging period, the highest (H1H) concentrations were chosen, regardless of the pollutant.

The Department background concentrations were added to these modeled concentrations for comparison to the applicable NAAQS, except for the particulates. The 24-hour and annual PM_{10} background concentrations were derived from one year of on-site PM_{10} monitoring data, which resulted in 23 and 7 $\mu g/m^3$, respectively. The $PM_{2.5}$ background concentrations were obtained from the Department Great Falls High School $PM_{2.5}$ monitoring site, 2005 – 2007 (http://deq.mt.gov/AirQuality/WhatsNew/PM25_NAAQS_MT_Review_Mar_2008.pdf). These three years of data determined the 24-hour and annual $PM_{2.5}$ design values for Great Falls. The corresponding $PM_{2.5}$ background concentrations were 18 and 5.9 $\mu g/m^3$, respectively. Finally, the Ozone Limiting Method was applied to adjust the 1-hour NO_x modeled concentrations to 1-hour NO_2 values. No adjustments were made to the annual NO_x concentration for conversion to annual NO_2 concentrations, which was a very conservative approach.

In the "Response to May 20, 2009 Department Request", page 30, Revised Table 4.5, the NAAQS/MAAQS results were reported for both Phase I (pre-steam Simple Cycle mode) and Phase II (Simple/Combined Cycle). For simplicity, the highest relevant modeled concentrations were selected for Table VI.E.1, regardless of the phase.

Table VI.E.1. NAAQS/MAAQS Results with the Potential HGS and Seven Off-Site Facility Emissions.

Pollutant	Averaging Period	Rank	NAAQS ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)	Met Year/ Source Group	Modeled Concentration [a] ($\mu g/m^3$)	Background Concentration [b] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Percent of NAAQS (%)	Percent of MAAQS (%)	Receptor Location UTM NAD27 Zone 12		Elevation (m)
											(mE)	(mN)	
$PM_{2.5}$	24-Hour	H8H	35	NA	NA/ CC_SS	6	18	24	69	NA	497520	5266097	1012
	Annual	H1H	15.0	NA	NA/ CC_SS	2	5.9	7.9	53	NA	497723	5266951	1003
PM_{10}	24-Hour	H2H	150	NA	2001/ ALL	11	23	34	23	NA	496700	5265400	1016
NO_x	1-Hour [c]	H2H	NA	564	2003/ SCSTEADY	237	75	312	NA	55	497420	5266093	1012
	Annual	H1H	100	94	1999/ CC_SS	4	6	10	10	11	497722	5266505	1006

a. The selected modeled concentrations were high-second-high (H2H) for the 24-hour averaging period and high-first-high (H1) for the annual averaging periods, except for 24-hour $PM_{2.5}$. The highest-eighth-high (H8H) modeled $PM_{2.5}$ concentrations was selected for comparison to the 24-hour standard.

b. All of the background concentrations are MDEQ defaults, except for the particulates. For PM10, the background concentrations were derived from one year of on-site PM10 monitoring data and the $PM_{2.5}$ background concentrations were from MTDEQ Great Falls High School $PM_{2.5}$ monitoring site, 2005 – 2007. These three years of data determined the 24-hour and annual $PM_{2.5}$ design values for Great Falls.

c. The Ozone Limiting Method was applied to adjust the modeled 1-hour NO_x concentrations to 1-hour NO_2.

None of the NAAQS/MAAQS were violated. The 24-hour $PM_{2.5}$ was the closest to a standard, about 69% of the NAAQS. The location of the corresponding receptor was on the fenceline near the southeast corner of the property. The other listed receptors were also on the fenceline (east, southeast, or south sides) near the emission sources, except for the high-second-high 24-hour PM_{10} concentration. This receptor was about 670 m south of the fenceline.

F. CLASS II PSD INCREMENT ANALYSES

As a conservative approach to the Class II PSD increment analysis, the same PM_{10} and NO_x modeled concentrations derived from the NAAQS/MAAQS analyses were used without the background concentrations and adjustment to the annual modeled NO_x to NO_2. This approach was conservative since the latest two-year average of actual emissions from the existing sources were only required. The results of the Class II PSD increment analysis are provided in Table VI.F.1

Table VI.F.1. PM_{10} and NO_x Class II PSD Increment Analysis.

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	Percent of Increment Consumed (%)	Compliance?
PM_{10}	24-Hour	11	30	37	YES
NO_x	Annual	4	25	16	YES

The PM_{10} HGS gas plant emissions had the most impact; about 37% of the 24-hour PM_{10} PSD Class II increment was consumed.

G. Summary of Class II Modeling Analyses

The $PM_{2.5}$, PM_{10}, and NO_x emissions from the HGS gas plant combined with the HGS coal plant emissions and the following six off-site industries did not violate any relevant NAAQS/MAAQS or Class II PSD increment: CHS Incorporated, Malmstrom Air Force Base, Malteurop North America, Montana Ethanol Project, Montana Refining Company, and Montgomery Great Falls Energy Partners LP.

H. Class I Area Modeling and Results

The HGS coal plant boiler stack emissions were not included in this modeling phase for several reasons. This CFB source would not be permitted to operate at the same time as the natural gas turbines. In addition, a Class I significant impact analysis was performed, which identified the potential impacts from the proposed emissions increase from the HGS gas plant. This can be considered as a screening technique; the predicted impacts were well below the significance levels for Class I areas so no further analysis was necessary. If further analysis was required, all near-by emission sources would be included such as the HGS coal plant and the other six off-site facilities used in the Class II analyses.

Visibility analysis was required since this permit action was for a modification at a PSD source and defined in the PSD rules, Subchapter 8 Prevention of Significant Deterioration of Air Quality (Administrative Rules of Montana 17.8.824 and 825) and Subchapter 11 Visibility Impact Assessment (ARM 17.8.1101-1111).

CALPUFF Modeling System Analysis

The Class I modeling analyses used the Federal Land Managers (FLM) Work Group guidance (FLAG, 2000)[5], IWAQM Phase II document (IWAQM, 1998)[6], the MDEQ Air Quality Permit Application guideline (MDEQ, 2007)[7], the Draft MDEQ CALPUFF BART Modeling Protocol for Federal Mandatory Class I Areas (CALPUFF Protocol), and USEPA guidance.[8] John Notar, National Park Service, provided several tables to apply Method 8, Mode 5, the new Monitoring of Protected Visual Environments (IMPROVE) equation to calculate light extinction (B_{ext}) from speciated aerosols.

Mr. Notar also requested the application of Method 2, which uses the original IMPROVE equation. This equation applies hourly relative humidity values from the CALPUFF visibility files with a maximum value of 95%. This method performs relatively well over a broad range of particle light scattering, but tends to underestimate the higher extinction values and overestimate the lowest ones. The new equation, Method 8, splits ammonium sulfate, ammonium nitrate, and organic carbon compound concentrations into two fractions: small and large. Site-specific rather than a network-wide Rayleigh scattering is used with the addition of two new terms for sea salt and absorption of NO_2. The average annual visibility conditions of the Class I areas was based on the information provided by Mr. Notar and the CALPUFF Protocol.

Class I Areas: Three distinct modeling analyses were performed: visibility, Class I PSD increment consumption, and deposition (not required). The following five federal mandatory Class I areas were considered. Also noted were the corresponding responsible FLMs and approximate distances from the HGS gas plant.

- Bob Marshall Wilderness Area (WA) - U.S. Forest Service (FS), 134 km
- Gates of the Mountains WA - FS, 88 km
- Glacier National Park - National Park Service (NPS), 192 km
- Scapegoat Wilderness Area - FS, 122 km
- UL Bend WA - U.S. Fish and Wildlife Service, 222 km

The responsible FLMs were provided the Application with the SME modeling analysis.

CALPUFF Modeling System: The following USEPA- approved versions were used:

Geophysical Data Processing:
- TERREL Version 3.684, Level 070327
- CTGCOMP Version 2.25, Level 070327
- CTGPROC Version 2.681, Level 070327
- MAKEGEO Version 2.29, Level 070327

[5] Federal Land Manager's Air Quality Related Values Workgroup (FLAG). 2000. "Federal Land Manager's Air Quality Related Values Workgroup (FLAG): Phase 1 Report." U.S. Forest Service. National Park Service. U.S. Fish and Wildlife Service. December 2000.

[6] Interagency Workgroup on Air Quality Modeling (IWAQM). 1998. "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts." EPA-454/R-98-019. December 1998.

[7] MDEQ. 2006. "Draft CALPUFF BART Modeling Protocol For Federal Mandatory Class I Areas." September 2006. Montana Department of Environmental Quality. Air Resources Management Bureau. P.O. Box 200901. Helena, Montana 59620-0901 [Online]. Available: http://www.epa.gov/region8/air/pdf/MontanaBARTProtocol0906.pdf

[8] USEPA. 2003. "Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule." EPA-454/B-03-005. Office of Air Quality Planning and Standards Emissions, Monitoring and Analysis Division. Air Quality Trends and Analysis Group. Research Triangle Park, NC. September 2003.

A more current CTGPROC version was available (Version 2.682, Level 070430). Bison reviewed the source code and notified the Department no change in the results would occur with the new version. This new program allows for use of compressed National Land Cover Data 1992 data, which was not used for this project.

Meteorological Preprocessors:
- SMERGE Version 5.57, Level 070627
- PXTRACT Version 4.25, Level 070327
- PMERGE Version 5.32, Level 070627
- READ62 Version 5.54, Level 070627

Main Models:
- CALMET Version 5.8, Level 070623
- CALPUFF Version 5.8, Level 070623

Postprocessors
- CALPOST Version 6.221, Level 070622
- POSTUTIL Version 1.56, Level 070627

The CALPUFF Protocol was used as the main document with some USEPA-regulatory defaults for the various CALPUFF modeling system input variables. The MESOPUFF II chemical transformation scheme, and wet and dry deposition calculations were applied. Through Department discussions, puff splitting was not used contrary to the CALPUFF Protocol. This decision was supported by the CALPUFF recommendations in the IWAQM report.[8] Members of IWAQM included the USEPA, U.S. Forest Service, the National Park Service, and the U.S. Fish and Wildlife Service. The last three organizations are the responsible parties of the federally mandated Class I areas.

Modeling Domain: The Department provided the GEO.DAT land use file to Bison, which defined the standard MDEQ CALPUFF modeling domain.

Land Use Data: For CALMET, land use data was obtained from the USGS website (http://edc2.usgs.gov/geodata/index.php). The data files for this project were 1:250,000 scale. Each land use cell was typically 200 m square, which was assigned a land use code.

Meteorology: Three years (2001 – 2003) of meteorological (met) data were used. The MDEQ provided the 2001 and 2003 CALMET data. Bison obtained the 2002 MM5 data through the Western Regional Air Partnership (WRAP) website (http://pah.cert.ucre.edu/aqm/308/bart.shtml). The MDEQ 2002 CALMET data contained missing periods of data between the months. The Department provided the surface met and precipitation data for 2002; no extrapolation was needed. The 2002 upper met data was obtained from the National Oceanic and Atmospheric Administration website (http://roab.fsl.noaa.gov). Upper air data substitution and extrapolation were accomplished as needed according to the Atmospheric Studies Group FAQ 2.3.4 (http://src.com/calpuff/FAQ-questions.htm). Refer to the CALPUFF Protocol for information about the upper and surface air, and precipitation data provided by the Department.

Receptors: The NPS provided the receptor sets for the Class I areas (http://www.nature.nps.gov/air/Maps/Receptors/index.cfm). The number of receptors for each area is as follows: Bob Marshall WA (788), Gates of the Mountains WA (194), Glacier National Park (790), Scapegoat WA (423), and UL Bend WA (134). These receptors were in longitude/latitude, NAD83. Bison did not convert to NAD27, the datum of this project, when converting the latitude/longitude to Lambert Conformal projection. A receptor in each of these two datum (NAD27 and NAD83) would be about 300 m apart in Montana. Due to the large distances between the HGS gas plant and the Class I areas, a few hundred meters would not affect the CALPUFF results.

Modeled Sources Data: Table VI.H.1 lists the HGS gas plant source emissions used in the Class I modeling analyses. The emission rates were identical to the Class II analyses, except Bison assumed 10% of the SO_2 emissions were sulfate (SO_4) emissions. The corresponding modeled source stack parameters did not change from the Class II analyses (Table VI.C.3).

Table VI.H.1. HGS Gas Plant Individual Source Maximum Hourly Emissions.

Description	HGS Gas Plant Emissions (lb/hr)			
	$PM_{10}/PM_{2.5}$	NO_x	SO_2	SO_4
SC SS West	4.80	36.58	0.57	0.057
SC SS East	4.80	36.58	0.57	0.057
CC SS West	7.20	4.16	0.69	0.069
CC SS East	7.20	4.16	0.69	0.069
SC SUSD West	4.80	36.58	0.57	0.057
SC SUSD East	4.80	36.58	0.57	0.057
CC SUSD West	7.20	26.12	0.69	0.069
CC SUSD East	7.20	26.12	0.69	0.069

The other HGS gas plant emission sources were not included since the turbine emissions were over 95% of the emissions. These turbine sources were arranged into four source groups: Simple Cycle Steady State, Combined Cycle Steady State, Simple Cycle SUSD, and Simple Cycle SUSD.

I. Class I PSD Increment Analysis

CALPOST was used to calculate the peak PM_{10}, NO_2, and SO_2 concentrations for comparison to the relevant Class I PSD increments and Class I Significant Impact Levels. For simplification, the highest concentrations were reported, regardless of the met year or operating mode (Simple or Combined Cycle). Tables VI.I.1 and VI.I.2 list the results for steady state and startup/down conditions, respectively.

Table VI.I.1. Maximum Class I PSD Increments for Steady State Conditions.

Pollutant	Averaging Period	Class I Wilderness Area	Met Year	Predicted Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
PM_{10}	24-Hour	Gates of the Mountains	2003	0.03467	8	0.3
	Annual	UL Bend	2002	0.00142	4	0.2
NO_2	Annual	Gates of the Mountains	2002	0.00254	2.5	0.1
SO_2	3-Hour	Gates of the Mountains	2001	0.01042	25	1.0
	24-Hour	Gates of the Mountains	2003	0.00238	5	0.2
	Annual	UL Bend	2002	0.00010	2	0.1

Table VI.I.2. Maximum Class I PSD Increments for Startup/Shutdown Conditions.

Pollutant	Averaging Period	Class I Wilderness Area	Met Year	Predicted Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
PM_{10}	24-Hour	Gates of the Mountains	2003	0.03512	8	0.3
	Annual	UL Bend	2002	0.00144	4	0.2
NO_2	Annual	UL Bend	2002	0.00262	2.5	0.1
SO_2	3-Hour	Gates of the Mountains	2001	0.01037	25	1.0
	24-Hour	Gates of the Mountains	2003	0.00241	5	0.2
	Annual	UL Bend	2002	0.00010	2	0.1

None of the Class I significance levels were exceeded so no further analysis was necessary (i.e., deposition). The Combined Cycle turbine PM_{10} emissions had the greatest impacts, about 12% and 0.4%, on the 24-hour PM_{10} Class I increment and significance level, respectively, at the Gates of the Mountains WA. In 11 out of 12 cases, the Combined Cycle emissions had the greatest effect, regardless of the operating mode. There were also little differences in the resulting concentrations between the two operating modes.

J. Class I Visibility Impacts

Both Method 2 and Method 8, the "new" IMPROVE reconstructed light extinction equation, were applied at the request of the NPS. The unit of visibility was the deciview (dv); the scale is linear with respect to the perceived visual change over the entire range of the scale. Both Methods compared the 98th percentile 24-hour change in visibilities from the HGS gas plant emissions to the 24-hour natural background visibility conditions at each Class I area; the 98th percentile was equivalent to the high-eighth-high (H8H) change in deciview (Δ dv). A change in 0.5 deciviews is essentially equivalent to a 5% change. The NPS considers a change greater than or equal to 5% in any one met year a violation and refined analysis would be required including the emissions from the near-by industrial sources.

The annual average natural background visibility conditions must first be calculated for the five Class I areas. To calculate the natural background conditions, six light extinction specie concentrations must be computed, which are entered into the each Method equation. Bison used the Department CALPUFF Protocol to calculate these specie background concentrations as listed in Table VI.J.1 although the NPS provided the annual average natural background data. Bison used the default average annual natural background aerosol concentrations for the "West" U.S.[10] To compute these background concentrations, Bison used "10" as the Rayleigh scattering value for all of the Class I areas. Using a higher Rayleigh value would have increased all of the background extinction specie concentrations whereas a lower one would have decreased the values. The values in Table VI.J.1 were not significantly different than the ones provided by the NPS, except for the Gates of the Mountains WA Coarse Particulate Matter (CPM). In this case, the NPS value was about half of the concentration used by Bison. However, this specie is a small factor in both Method equations that were used to calculate the light extinctions for the natural background conditions and the change in the light extinctions from the HGS gas plant emissions.

Table VI.J.1. Class I Area Background Extinction Specie Concentrations (μg/m^3)

Specie	Bob Marshall WA	Gates of the Mountains WA	Glacier NP	Scapegoat WA	UL Bend WA
Ammonium Sulfate (SO_4)	0.121	0.120	0.120	0.119	0.120
Ammonium Nitrate (NO_3)	0.101	0.100	0.100	0.099	0.100
Coarse Particulate Matter (PMC)	3.021	3.000	3.005	2.966	3.004
Organic Carbon (OC)	0.473	0.470	0.471	0.465	0.471
Soil	0.503	0.500	0.501	0.494	0.501
Elemental Carbon (EC)	0.020	0.020	0.020	0.020	0.020

Tables VI.J.2 and VI.J.3 list these results for steady state and startup/shutdown conditions, respectively, at each Class I area. Both Methods 2 and 8 were included with the number of days greater than or equal to 0.5 dv.

Table VI.J.2. H8H Maximum 24-Hour Visibility Impacts for Steady State Conditions.

Class I Area	Method 2				Method 8			
	Met Year	ΔB_{ext} (dv)	# of Days ΔB_{ext} (dv) > 0.5 dv	# of Days ΔB_{ext} (dv) > 1.0 dv	Met Year	ΔB_{ext} (dv)	# of Days ΔB_{ext} (dv) > 0.5 dv	# of Days ΔB_{ext} (dv) > 1.0 dv
Bob Marshall WA	2001, 2003	0.040	0	0	2001	0.027	0	0
Gates of the Mountains WA	2002	0.096	0	0	2002	0.084	0	0
Glacier NP	2001, 2002	0.014	0	0	2001, 2002	0.015	0	0
Scapegoat WA	2002	0.031	0	0	2002	0.031	0	0
UL Bend WA	2002	0.082	0	0	2002	0.061	0	0

Table VI.J.3. H8H Maximum 24-Hour Visibility Impacts for Startup/Shutdown Conditions.

Class I Area	Method 2				Method 8			
	Met Year	ΔB_{ext} (dv)[1]	# of Days ΔB_{ext} (dv) > 0.5 dv	# of Days ΔB_{ext} (dv) > 1.0 dv	Met Year	ΔB_{ext} (dv)	# of Days ΔB_{ext} (dv) > 0.5 dv	# of Days ΔB_{ext} (dv) > 1.0 dv
Bob Marshall WA	2003	0.045	0	0	2001	0.031	0	0
Gates of the Mountains WA	2002	0.096	0	0	2002	0.091	0	0
Glacier NP	2002	0.014	0	0	2001	0.016	0	0
Scapegoat WA	2001, 2002	0.029	0	0	2002	0.032	0	0
UL Bend WA	2002	0.107	0	0	2002	0.074	0	0

None of the values exceeded the threshold of 0.5 dv change at any Class I area. The maximum 24-hour change in visibility from natural background conditions was 0.107 dv at UL Bend WA from the NG HGS Simple Cycle turbine emissions, under startup/shutdown conditions. In most cases, the application of Method 2 produced higher 24-hour change in the light extinction values than Method 8. Regardless of the operating mode, the Simple Cycle turbine emissions had the greatest affect on the natural background visibilities at all of the Class I areas, probably due to the higher NO_x emission rates.

K. Class I Area Deposition Impacts

CALPUFF produces two binary files containing wet and dry flux rates for several nitrogen and sulfur-containing compounds. These compounds would be produced from atmospheric reactions over time. The CALPUFF postprocessor POSTUTIL combined the individual wet and dry deposition fluxes into total individual wet and dry nitrogen and sulfur deposition rates. The sulfur and nitrogen weighted species in the POSTUTIL input files were based on the IWAQM Phase 2 report, p. 31 Then CALPOST was used to estimate the total deposition (wet + dry) rates for each individual chemical specie. For sulfur, both wet and dry SO_2 and sulfate (SO_4) deposition were evaluated. Total nitrogen estimates included NO_x, nitric acid (HNO_3), and nitrate ion (NO_3). CALPOST calculated the total wet and dry deposition in micrograms per square meter per second ($\mu g/m^2$-s); Bison converted these units into kilograms per hectare per year (kg/ha-yr). The results were compared to the FS and NPS sulfur and nitrogen deposition thresholds. The FS deposition thresholds vary for different locations; however the lowest "green line" sulfur and nitrogen deposition values are 3 kg/ha-yr. The NPS West Deposition Analysis Thresholds (DATs) for sulfur and nitrogen is 0.005 kg/ha/yr.[9] For simplification, the maximum annual nitrogen and sulfur deposition rates were reported, regardless of the met year or operating condition. Tables VI.K.1 and VI.K.2 list the results for both steady state and startup/shutdown conditions, respectively.

[9] National Park Service. Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds. [Online]. Available: http://www2.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf.

Table VI.K.1. Maximum Deposition for Steady State Conditions.

Class I Area	Nitrogen		Sulfur	
	Met Year	Deposition (kg/ha/yr)	Met Year	Deposition (kg/ha/yr)
Bob Marshall WA	2002	2.09E-04	2003	1.17E-05
Gates of the Mountains WA	2002	1.01E-03	2002	4.57E-05
Glacier NP	2002	7.99E-05	2002	5.27E-06
Scapegoat WA	2003	3.12E-04	2003	1.85E-05
UL Bend WA	2002	5.57E-04	2002	3.03E-05

Table VI.K.2. Maximum Deposition for Startup/Shutdown Conditions.

Class I Area	Nitrogen		Sulfur	
	Met Year	Deposition (kg/ha/yr)	Met Year	Deposition (kg/ha/yr)
Bob Marshall WA	2003	2.10E-04	2003	1.13E-05
Gates of the Mountains WA	2002	9.55E-04	2002	4.53E-05
Glacier NP	2002	8.55E-05	2002	5.23E-06
Scapegoat WA	2002	3.01E-04	2003	1.82E-05
UL Bend WA	2003	6.06E-04	2002	3.05E-05

The results indicated that neither the FS green line nor NPS DAT was exceeded. Regardless of the operating mode, the higher Simple Cycle turbine NO_x emissions produced higher nitrogen deposition rates in contrast to the higher SO_2 and SO_4 emissions of the Combined Cycle turbines that caused higher sulfur deposition impacts.

L. Summary of Class I Analyses

The Simple and Combined Cycle turbine emissions did not consume any Class I PSD increment, reduce visibility, or cause acid deposition from nitrogen and sulfur-based compounds at the following Class I areas: Bob Marshall WA, Gates of the Mountains WA, Glacier NP, Scapegoat WA, and UL Bend WA.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (e.g., right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Southern Montana Electric Generation and Transmission Cooperative, Inc. – Highwood Generating Station Natural Gas Plant

Air Quality Permit Number: 4429-00

Preliminary Determination Issued: August 31, 2009
Department Decision Issued: October 16, 2009
Permit Final: November 1, 2009

1. *Legal Description of Site*: Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana

2. *Description of Project*: Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME) proposes to construct and operate a natural gas-fired power plant and combust natural gas at the Highwood Generation Station (HGS) facility ("the Project"), to generate electrical power. The proposed action is to issue Montana Air Quality Permit #4429-00 to SME, allowing construction and operation of two natural gas combustion turbines for electric power generation. Initially, the gas plant was planned as an addition to the formerly permitted HGS coal plant facility (MAQP #3423-01). Following submission of the HGS gas plant application, SME requested that the Department revoke MAQP #3423-01 for the HGS coal plant. Revocation of MAQP #3423-01 became final on August 20, 2009. The proposed HGS gas plant would be located within the existing boundary of the property on which the HGS coal plant was to have been built. SME proposes to build a 120-megawatt (MW) natural gas-fired power plant located approximately eight miles east-northeast of Great Falls, Montana, within Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana (Figure 1.) (Stanley, 2009a).

   Figure 2. is an image of how the gas plant facility would generally appear. The proposed Project would consist of the following main structures: 2 simple cycle combustion turbine generators, each with an 80 foot stack; 2 heat recovery steam generators (HRSG), each with a 105 foot stack; a 70 foot high control/administrative/maintenance activities and steam turbine generator building; a 45 foot high cooling tower structure; and a 30 foot high water treatment building

   Construction of the Project is estimated to require up to 320 construction workers over a period of 30 months. The number of workers on-site at any given time will vary throughout the course of construction. Operation of the facility would employ approximately 20 people full-time.

   Initially, the Project would include two natural gas-fired turbines, each powering dedicated electric generators. A second phase of the project would add a heat recovery steam generator following each natural gas turbine, and these steam generators would power an additional single electric steam turbine generator.

   The HGS would interconnect with existing electrical transmission facilities owned by Northwestern Energy. The initial interconnection would be with an existing 230 kV line that runs from the Great Falls Substation to the Broadview Substation, near the junction of Salem Road and Highway 228 and would not cross the NHL. There are a number of transmission facilities close to the HGS site. If

there is a need for future interconnection capacity, and that connection would involve an aerial crossing of the Missouri River, SME would be required to obtain any necessary permits for the crossing at that time. Currently, several transmission lines cross the Missouri River, and SME has stated that it would evaluate connecting with those lines, in determining future interconnection options.

A new natural gas line would be installed to connect the Project to existing gas transmission pipelines north of the Missouri River. Northwestern Energy would construct and operate the line, which would serve SME and SME understands that it may not only be sized to meet their needs but also the needs of future natural gas customers. Northwestern would have discretion regarding siting of the pipeline, however, SME has stated that it understands that the line would begin approximately 5 miles northeast of Great Falls, then proceed generally east to the HGS site, extending approximately 9.3 miles. The pipeline would cross under the Missouri River approximately 5 ½ miles west of the HGS facility, extend west across the property to the east of the river, and then cross the National Historic Landmark (NHL) in a northeasterly direction toward the HGS facility.

Much of the information for this EA is based on the significant body of research that was assembled for the HGS coal plant final Environmental Impact Statement (RUS and MDEQ, 2007a) issued in January 2007 ("the EIS") and a Record of Decision (ROD) issued in May 2007 (RUS and MDEQ, 2007b). A copy of the EIS is available for review on the Department web site at ***http://www.deq.mt.gov/eis.asp***, or a compact disc may be obtained from the Department upon request. The EIS was prepared by the Mangi Environmental Group, Inc. for the U.S. Department of Agriculture Rural Utilities Service (RUS) and the Department.

Figure 1. Vicinity Map of Project Site

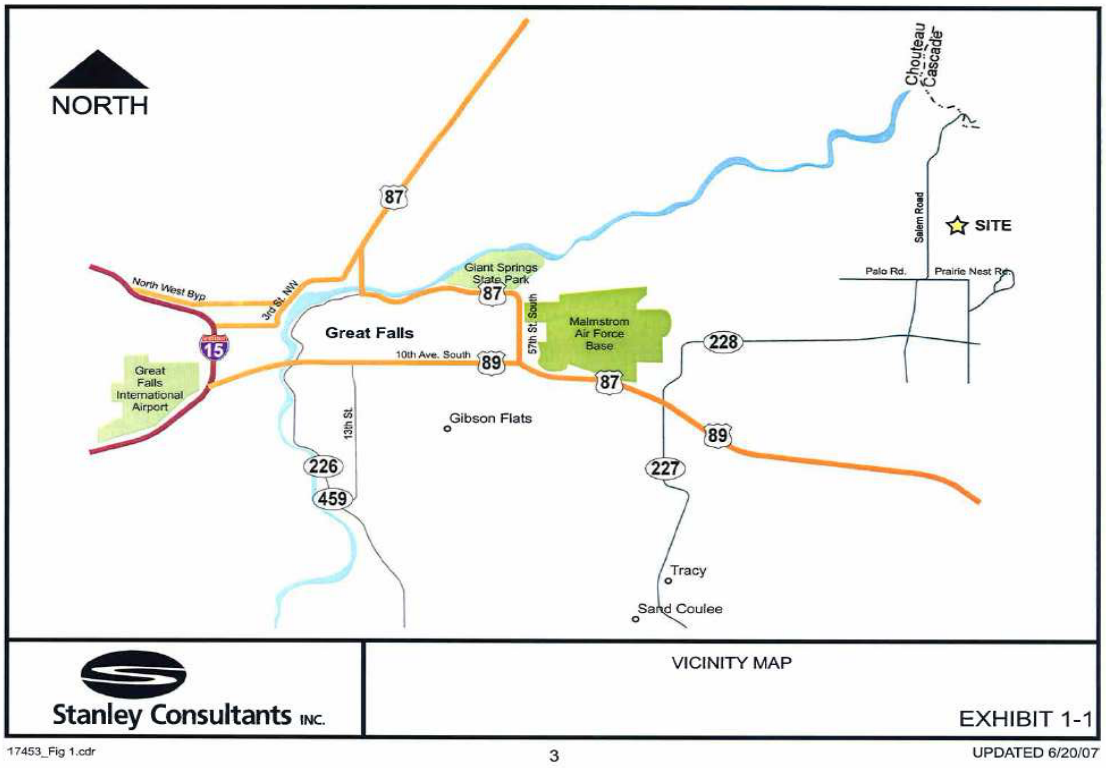
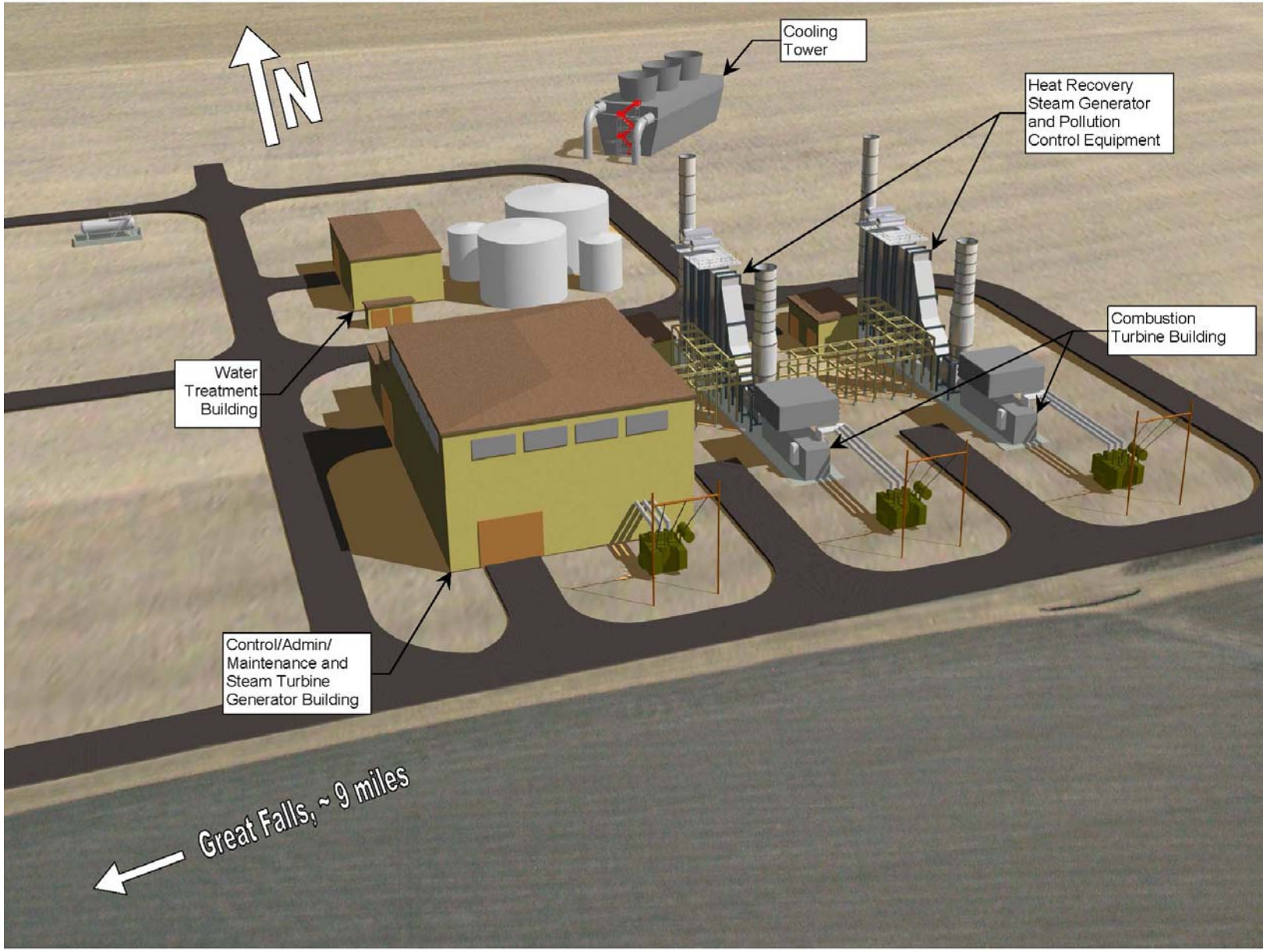


Figure 2.Isometric Image of the Project



3. *Benefits and Purpose of Project*: The objective of the Project is to fulfill a need for electric power. SME is a non-profit, member-owned electric generation and transmission cooperative based in Billings, Montana. It provides wholesale electricity and related services to five electric distribution cooperatives and to the City of Great Falls, Montana. Under its charter, SME is required to meet the electric power needs of its members, who are located throughout 58,000 square miles of Montana and a small section of Wyoming. The Project could provide reliable electricity at reduced rates for SME's customer base.

   SME previously identified a need to replace a substantial portion of its electrical power generation portfolio when existing power purchase agreements expire. SME commissioned a study in 2004 of alternative options to meet this demand. The study concluded that construction and operation of a 250 MW coal-fired power plant would optimize power supply security and costs for cooperative members. A related study identified the location of the proposed HGS gas plant as an optimum site for the coal-fired generation facility (SME, 2004b).

   Since publication of the final EIS, changing conditions in national and international economies and financial systems, in addition to projected new environmental regulations, combined to make construction of coal-fired power generation facilities more difficult than when the power generation project was initially planned.

   Although generally considered to be more expensive to operate than a coal-fired plant, a natural gas-fired plant costs substantially less to build, takes less time to construct, and is easier to finance. SME has stated that these factors led SME to modify its earlier plans with respect to the coal plant. SME has informed the Department that it has abandoned its plans to construct the coal-fired plant, and, instead, intends to meet its near and long-term power supply needs through the natural gas-fired facility. SME intends the facility to provide electrical power to Beartooth Electric, Fergus Electric, Mid Yellowstone Electric, and Tongue River Electric Cooperative. Yellowstone Valley Electric Cooperative is not participating in construction of the gas plant, and its electrical power supply requirements were not considered in determining the necessary capacity of the natural gas plant.

   To meet its interim power supply needs, SME has entered into short-term contracts with PPL Montana. PPL is providing this power with generation capacity from its Colstrip and Corette coal-fired electrical generation facilities. Southern Montana has a number of these power purchase contracts in place with PPL Montana. The last contract is scheduled to expire in 2019. However, SME has stated that these contractual purchase rights are not sufficient to meet SME's forecasted supply requirements and related ancillary service needs, including peaking and load following, and that the gas-fired generation facility would predictably, reliably, and economically fulfill those requirements. SME has also stated that the proposed facility will enable them to cost effectively follow system load and effectively manage the cost of the services it provides to its member systems. SME believes that the ability to provide this type of supply product is an essential attribute of SME's ability to meet the wholesale power and related energy services needs of the member systems it serves.

4. *Alternatives Considered:* As SME evaluated its power supply alternatives under the guidance of RUS, SME reviewed wholesale power supply alternatives capable of meeting the current and forecasted demand for wholesale electric energy and related service needs of the distribution member systems it serves. The conclusion reached in this evaluation of viable power supply alternatives was that the construction of a new fossil fuel power generation facility at the HGS site represented the best long-term power supply alternative to meet the growing needs of SME'S member systems. In the context of this analysis, SME evaluated alternative generation technologies and plant locations. Both studies are described in the EIS.

Subsequent to completion of the alternative evaluation study, there have been significant changes in the regulatory and financial environments. The net result of these changes materially impacted the viability of proposed and existing coal-fired electric generation facilities. SME has stated that, based on this marked change in the external conditions impacting electric generation capacity development, SME now believes that natural gas-fired generation, complemented with competitively priced power purchase agreements, represents the most reasonable near term solution to the power supply needs of SME and the member systems it serves. Based on its desire for a higher level of power supply certainty, SME decided to develop the natural gas-fired generation facility.

In Section 2.1.3 of the EIS, RUS and the Department rejected consideration of a number of non-combustible energy resources. Also, RUS and the Department analyzed placement of the HGS at the Great Falls Industrial Site in the EIS.

ARM 17.4.609(3)(f) requires the Department to consider, in an EA, reasonable alternatives to a proposed action whenever alternatives are reasonably available and prudent to consider. Under 75-1-201(5)(a) of the Montana Environmental Policy Act, an agency may not withhold, deny, or condition a permit based on MEPA. The Department's authority regarding this application is contained in the Clean Air Act of Montana and the rules adopted pursuant to it. That authority is to approve SME's permit application if it meets the requirements of the Act and rules and to disapprove it if the Act or rules are not met. Consequently, the alternatives that are reasonably available to the Department and prudent to consider in this EA are the alternatives of denial of the permit, which is the "no action" alternative, and issuance of the permit. Because the Department has no authority to require siting of the HGS at an alternative location as long as air quality laws and rules would be met at the Salem site or to require SME to use alternative energy sources, no other alternative sites or energy resources are analyzed in this EA.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in Permit #4429-00.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Aquatic and Terrestrial Life and Habitats			X			Yes
B	Water Quality, Quantity, and Distribution			X			Yes
C	Waste Management			X			Yes
D	Geology and Soil Quality, Stability and Moisture			X			Yes
E	Vegetation Cover, Quantity, and Quality			X			Yes
F	Aesthetics		X				Yes
G	Air Quality			X			Yes
H	Unique Endangered, Fragile, or Limited Environmental Resources			X			Yes
I	Demands on Environmental Resource of Water, Air and Energy			X			Yes
J	Historical and Archaeological Sites		X				Yes
K	Cumulative and Secondary Impacts			X			Yes

A. Aquatic and Terrestrial Life and Habitats

The area surrounding Great Falls is dominated by grassland and is used primarily for agricultural activities with isolated areas of urban, suburban, rural, and industrial development. The topography is mostly flat with some drainages created by creeks, rivers, and wind erosion. Shrubs and trees grow mostly in the drainages and canyon areas. The Project site currently is privately owned farmland used for producing small grains. SME has purchased the former farmland property on which it proposes to construct the HGS gas-fired plant. The HGS gas plant would reside within the property boundary previously identified for the HGS coal-fired plant.

Aquatic Life and Habitats

Wetlands within the general area are limited to the incised drainage habitat and narrow fringes of the Missouri River and its tributaries (WESTECH, 2005). Though limited, these wetlands provide an invaluable resource for the filtration and adsorption of stream nutrients and contaminants, and for waterfowl and wildlife habitat. Field surveys and reviews of aerial photographs revealed a few isolated wetlands along Box Elder Creek and the Missouri River (RUS AND MDEQ, 2007a).

Terrestrial Life and Habitats

Impacts to terrestrial life and habitats from construction and operation of the HGS gas plant would be minor because of the relatively small portion of land that would be disturbed. The total footprint of the Project would be approximately six acres. Some surface disturbance would occur beyond the plant site with the construction of at least one transmission line, a natural gas pipeline to the facility, and access roads.

Westech Environmental Services, Inc. (WESTECH) researched previously recorded wildlife sightings within a ten mile radius of the Project site and areas surrounding the proposed transmission lines (WESTECH, 2005). This research included interviews with landowners and with specialists from FWP.

Mule deer, white-tailed deer, and pronghorn antelope are known to be present in the area. Of these, mule deer are the most abundant. Mule deer inhabit the surrounding areas year round and frequent the area's many drainages and fields. White-tailed deer primarily inhabit drainages with riparian habitat. The area is not conducive to large pronghorn populations, as most of the native vegetation has been converted to agriculture.

The Project site is just to the west of a 70-square-mile area which is surveyed for deer populations four times per year by Montana Fish, Wildlife and Parks (FWP). Recent FWP counts of these species have shown populations of approximately 500 mule deer, 50 white-tailed deer, and 100 pronghorn in the surveyed area (RUS AND MDEQ, 2007a). Other wildlife species potentially in this area include bobcat, coyote, gray partridge, mountain lion, red fox, and sharp-tailed grouse.

Environmental Consequences

The HGS would interconnect with existing transmission facilities owned by Northwestern Energy. The initial interconnection would be with an existing 230 kV line that runs from the Great Falls Substation to the Broadview Substation, near the junction of Salem Road and Highway 228 and would not cross the NHL. There are a number of transmission facilities close to the HGS site. If there is a need for future interconnection capacity, and that connection would involve an aerial crossing of the Missouri River, SME would be required to obtain any necessary permits for the crossing at that time. Currently, several transmission lines cross the Missouri River, and SME has stated that it would evaluate connecting with those lines, in determining future interconnection options.

A new natural gas line would be installed to connect the Project to existing gas transmission pipelines north of the Missouri River. Northwestern Energy would construct and operate the line, which would serve SME as well as other Northwestern customers. Northwestern would have discretion regarding siting of the pipeline, however, SME's understanding is that the line would begin approximately 5 miles northeast of Great Falls, then proceed generally east to the HGS site, extending approximately 9.3 miles. The pipeline would cross under the Missouri River approximately 5 ½ miles west of the HGS facility, extend west across the property to the east of the river, and then cross the NHL in a northeasterly direction toward the HGS facility. Because the pipeline would be drilled under the river, impacts to aquatic habitats would be minor at most. However, Northwestern would be required to obtain all necessary state and/or federal permits, and environmental analysis would be conducted pursuant to MEPA, and NEPA if it applies, at that time.

Adverse effects to flora and fauna may occur through construction or operation of the facility or infrastructure as described in the coal-fired generation facility EIS (RUS AND MDEQ, 2007a, pp. 4-58 through 4-69). Wildlife could experience mortality directly due to construction or operation of the facility or its infrastructure, or indirectly through habitat loss, fragmentation, or conversion. Vegetation can be directly affected by its removal as the ground surface on which it occurs is developed, or indirectly through changing populations of wildlife that feed on plants. However, other than the few small buildings constructed or moved to the site and the construction that has occurred at the site to date for the coal plant, the HGS site currently consists of cultivated cropland, and it is surrounded by cultivated cropland. Neither the gas plant nor any of its infrastructure would be located in any wetlands.

SME would be required to follow the requirements identified in the Cascade County Weed and Mosquito Management District's document, "Weed Management and Revegetation Requirements for Disturbed Areas in Cascade County, Montana." This document specifies the actions that need to be taken prior to disturbance, during operation, and upon reclamation, to prevent the spread of noxious weeds in the county.

Impacts Summary

Impacts to biological resources from constructing and operating the HGS gas plant at the Project site and transmission line would be similar to, but less than, those that would have resulted from the coal-fired power plant. Similar to the analysis in the coal facility EIS (RUS AND MDEQ, 2007a), the biological impacts of the Project would be minor. The No Action Alternative would have no direct effects on biological resources at the Project site.

B. Water Quality, Quantity and Distribution

Surface Water

The primary drainage that would be nearest to the plant site is Belt Creek. It joins the Missouri just downstream of the Project site, approximately 15 river miles northeast of Great Falls.

There are several intermittent streams in the vicinity of the Project site. To the east, drainage from the site would flow into Rogers Coulee, a drainage channel that connects with Belt Creek just northeast of the site. To the west of the site, and located immediately west of Salem Road, there are several unnamed drainage channels with intermittent flows to the Missouri River. Rogers Coulee and these drainages are dry the majority of the year and contain flowing water only during major overland runoff events. Box Elder Creek is the first named tributary of the river located to the west of the site. Surface water flows in a north to northeast direction throughout this area, into the Missouri River.

Wetlands within the general area are limited to the incised drainage habitat and narrow fringes of the Missouri River and its tributaries (Westech, 2005). Though limited, these wetlands provide an invaluable resource for the filtration and adsorption of stream nutrients and contaminants, and for waterfowl and wildlife habitat.

Floodplains similarly follow the fringes of the perennial streams in the area. Along the Missouri River in the vicinity of the Project area, the floodplains do not extend over the river banks due to the fact that the river runs through a deeply incised channel with sides from sixty to over several hundred feet high (Nerud, 2006). The configuration and size of the channel, along with the area dams, prevent the Project site from receiving most flood waters.

Groundwater

The few producing water wells in the vicinity of the plant site are at least a mile away and are completed in the Kootenai and Madison formations.

The upper portion of the Kootenai Formation consists primarily of mudstone with some claystone and siltstone. The lower portion of the Kootenai is characterized by sandstone and siltstone, which are the common sources of groundwater in the formation (PBSJ, 2006). The Madison Formation is composed primarily of limestone, which contains the aquifer in that formation. Total well depths range from 356 to 605 feet. Production rates range from 3 to 350 gallons per minute (MBMG, 2009).

Alluvial groundwater is found along the Missouri River. No wells are recorded in this alluvial aquifer in the project's vicinity. SME plans to use alluvial wells as a source of process water. These would be drilled near Morony Dam. (MBMG 2009). Montana Bureau of Mines and Geology. 2009. Groundwater Information Center. Accessed on 8/28/09 at: http://mbmggwic.mtech.edu.

Environmental Consequences

Construction of the Project is expected to last up to 30 months. General construction impacts could indirectly affect water resources by increased storm water runoff from the Project site carrying sediment and contamination loads into surface water, and by contamination from construction equipment and activities infiltrating area soils and percolating down into the groundwater. Direct impacts to water resources may result from construction activities including the alluvial wells adjacent to the Morony Reservoir, and the installation of a transmission line and water and natural gas pipelines within the watershed of the Missouri River. The routes for the transmission line and gas pipeline are discussed above under "Aquatic Life and Habitats." The route for the water pipeline is described in the EIS (RUS and MDEQ, 2007a, pp. 4-62. As with almost any construction project involving the use of heavy equipment, there is some risk of an accidental fuel or chemical spill, which could adversely affect water quality if the spilled chemical were to percolate into groundwater or directly enter an adjacent surface water body. The gas plant, transmission line, and natural gas pipeline would not be located in any wetlands.

Potable water needs for the plant would be satisfied by delivery of fresh potable water from the City of Great Falls water lines through installation of a 55,000 foot pipeline or by transporting potable water to the facility from offsite.

The Project would obtain water required for its operation from water drawn from wells and transported to the project site through a pipeline. SME met with the U.S. Army Corps of Engineers on August 27, 2009, in Portland, Oregon to bring closure to all permits and related activities under the jurisdiction of the U.S. Army Corps of Engineers associated with the abandoned coal fired facility. The need for interaction with the U.S. Army Corps of Engineers was primarily a function of a need to install a raw water intake structure in Morony Pool. At this time SME does not see a need to submit a new application for permission to place an intake structure in the Missouri River at Morony Pool.

SME's raw water needs will now be met with water drawn from wells and transported to the project site through a pipeline that will be located on an easement purchased across private property that will not require any additional permitting. The wells would be projected to be adjacent to Morony Reservoir, approximately 0.4 mile upstream of Morony Dam on the Missouri River. As discussed in the EIS, withdrawal of larger quantities of water from the Missouri River would have a minimal impact on river flows. The development of wells adjacent to the Morony Reservoir would pull surface water from Morony Reservoir and potentially could impact the groundwater resources in the area; however, those impacts are expected to be localized in the alluvial aquifer immediately adjacent to the reservoir. Groundwater aquifers at the plant site would not be affected.

SME's needs for raw water at the Project site have been reduced from approximately 3,100 gallons per minute to less than 100 gallons per minute during simple cycle operation. Water consumption may be approximately 700 gallons per minute when operating in combined cycle mode. The approximate water usage for the Project is summarized in the table below:

Estimated Average Water Usage for the Highwood Generating Station Gas Plant

Operational Mode	Water Intake (GPM)	Cooling Towers Evaporation (GPM)	Misc. Water Use (GPM)	Water Discharge (GPM)
Simple Cycle	100	0	100	0
Combined Cycle	700	400	100	200

The power plant would generate a maximum of 216 gpm of wastewater that must be treated and would consist of concentrated river water and trace amounts of cooling tower water and boiler water treatment chemicals (RUS and MDEQ, 2007a). The wastewater would be discharged back to the City of Great Falls through 55,000 feet (10 miles) of wastewater pipeline for disposal at its existing wastewater treatment facility or would be treated and evaporated on-site, resulting in zero wastewater discharge from the Project site. Sanitary waste water would be routed to a septic leach field adjacent to the plant. The City of Great Falls wastewater treatment facility is licensed and permitted to treat and discharge up to 21 million gpd into the Missouri River (MPDES MT 0021920). An Industrial Wastewater Permit would be required from the City of Great Falls for these discharges. In addition, a wastewater pond would be constructed on site in order to provide surge control and to contain steam cycle blowdown and sump discharges from turbine and transformer areas. The sump discharges would undergo treatment in a standard oil/water separator unit prior to entering the basin. No toxic organic compounds would be present in the discharged wastewater. SME would be required to install and operate wastewater sampling and monitoring equipment. Because all process-related discharges from the facility would be sent to the Great Falls sanitary sewer or treated on-site, there would be no adverse impacts on water resources from operation of the facility.

Storm water run-off from the Project site would be channeled into plant storm ponds and managed in accordance with the facility Storm Water Permit. SME or its contractor would be required to obtain, from the Department, a General Permit for Storm Water Discharges Associated with Construction Activities, and SME would be required to obtain coverage under a General Permit for Storm Water Discharges Associated with Industrial Activity or obtain an individual National Pollutant Discharge Elimination System (NPDES) permit. SME also would be required to develop a Storm Water Pollution Prevention Plan (SWPPP) for the Project. Pursuant to the permits and SWPPP, SME would be required to: use Best Management Practices (BMPs) during construction, such as use of silt fences, straw bales, and other temporary measures to control erosion from storm runoff; to construct temporary sediment basins before mass grading begins and maintain them until site vegetation is firmly established; revegetate all disturbed areas; during operation, contain storm water run-off from the Project site in plant storm ponds or manage storm water runoff in accordance with the facility Storm Water Permit; and, to reduce the potential for water resource contamination, store and maintain all fuels in a designated equipment staging area, away from water bodies.

Additional permits and authorizations that may be required for construction activities in or adjacent to water bodies include: U.S. Army Corps of Engineers Section 10 and Section 404; Montana DEQ 401 Certification and 318 Authorization; and Cascade County 310 and Floodplain permits. Section 10 Permit (Federal Rivers and Harbors Act) - regulates construction of any structure in or over any federally listed navigable waters of the United States, the excavation from or depositing of material in such waters, or the accomplishment of any other work affecting the course, location, condition, or capacity of such waters (U.S. Army Corps of Engineers); 404 Permit (Federal Clean Water Act) controls discharge of dredged or fill materials in wetlands and other water of the U.S. (U.S. Army Corps of Engineers); 401 Certification (Federal Clean Water Act) before issuing a 404 Permit, the Corps of Engineers must obtain certification of compliance with the Department's water quality standards; Short-Term Water Quality Standard For Turbidity

(318 Authorization) (Montana Water Quality Act) required for any activity in any state water that will cause unavoidable short-term violations of the Department's water quality standards for turbidity; 310 Permit (Montana Natural Streambed and Land Preservation Act) required to perform work that physically alters or modifies the bed or banks of a perennial stream (Cascade County Conservation District); Cascade County Floodplain Permit (Montana Floodplain and Floodway Management Act) required to build permanent structures or to place fill in a designated flood plain (Cascade County Planning Department). Northwestern may also be required to obtain some of these permits for action undertaken on the pipeline.

Impacts Summary

Construction of the facility for up to a 30-month period would have the potential to generate storm water runoff that could impact nearby water bodies. SME would be required to manage storm water runoff in accordance with a Department-approved Storm Water Permit and SWPPP for the project, to mitigate this potential to the point of negligible impacts.

Potable water needs would either be satisfied by fresh potable water supply from the City of Great Falls water lines or by transporting potable water to the facility from offsite. Either case is anticipated to have minor impacts on water resources.

Water supply for operations at the Project would have the potential to impact the nearby alluvial groundwater. As described in the EIS, water withdrawals from alluvium immediately adjacent to the Morony Reservoir would be expected to directly connect to surface water in the reservoir, and would have only a localized impact on alluvial groundwater. As outlined above, impacts of water use by the Project on water resources are anticipated to be minor.

Wastewater discharge from the Project either would be returned to the City of Great Falls sanitary sewer system or would be treated and evaporated on-site to the point of zero discharge of wastewater. Either case is anticipated to have minor impacts on water resources. The No-Action Alternative would have no effect on the groundwater or surface water resources around the Project site.

C. Waste Management

As described in the EIS (RUS and DEQ, 2007a), the primary landfill in the Great Falls area is the High Plains Sanitary Landfill and Recycle Center (HPSL). This landfill is a licensed Class II landfill. Four other landfills exist in the area, but these all are privately owned and accept limited quantities of waste from outside sources. Non-exempt regulated hazardous waste must be delivered to a permitted hazardous waste destination, such as an incinerator or hazardous waste landfill, the nearest of which are located out of state in Oregon and Utah.

Environmental Consequences

Construction of the Project would generate construction debris waste, which would require proper disposal or reuse. Any non-hazardous construction debris that could not be reused or recycled would be disposed of at the HPSL. The construction contractor would be responsible for ensuring that the waste material generated was properly disposed. Portable restrooms for employee use during the construction period would be provided by a private contractor. The contractor would be required to have portable toilets serviced by a septic tank pumper licensed by the Department to perform these services.

The Project would generate relatively low volumes of non-hazardous wastes and possibly small quantities of hazardous wastes. These waste streams would consist primarily of boiler blowdown waste, cooler blowdown waste, demineralizer regenerant, and boiler chemical cleaning wastes.

The power plant most likely would be regulated as a "conditionally exempt small quantity generator" of hazardous waste, and SME would be required to comply with rules applicable to conditionally exempt small quantity generators of hazardous waste. Conditionally exempt small generators are required to determine which of the wastes they generate are hazardous and keep records of any test results, waste analyses or other determinations used to characterize hazardous waste, for at least 3 years from the date of final disposition of the waste. They may dispose of hazardous waste at a legitimate recycling facility, a permitted hazardous waste treatment, storage, or disposal facility, or a Class II municipal solid waste landfill. SME would be required to use either of the first two options for disposal of any regulated hazardous wastes.

SME would discharge aqueous wastes, including sanitary wastes, to the City of Great Falls wastewater treatment facility in accordance with conditions established by the City or would treat and evaporate wastewater on site. SME would be required to comply with conditions established for discharging wastes to its water treatment facility.

Impacts Summary

Impacts from waste generation and disposal at the Project site would be typical of many industrial and commercial operations. Compliance with applicable solid waste rules, disposal of non-hazardous wastes at the HPSL, disposal of any regulated hazardous waste at an appropriate facility, and treatment of wastewater at the City of Great Falls wastewater treatment facility, or treatment and evaporation of wastewater onsite, would ensure that impacts to the environment from the Project's waste streams would be minor.

D. Geology and Soil Quality, Stability and Moisture

Great Falls is located within the Missouri Plateau region of the Great Plains physiographic area, which is characterized by several levels of rolling upland plains, small mountainous masses, and flat-topped buttes. The area is dissected by the Missouri River and its tributaries.

The regional topography in the Great Falls vicinity consists primarily of gently rolling northern Great Plains and prairie with little change in relief. Elevations in the area range from about 3,300 to 3,600 feet above mean sea level (MSL). Nearby mountain ranges partially encircle the Great Falls portion of the Missouri River valley. These include the Highwood and Little Belt Mountains, which are about 30 miles away to the east and south, respectively. The Big Belt Mountains are 40 miles distant to the southwest and the Front Range of the Rocky Mountains varies between 60 and 100 miles distance to the west and northwest.

The elevation at the planned facility location is approximately 3,310 feet above sea level. Site topography is gently sloping and undulating, sloping downward to the west and north toward the Missouri River.

A hydrogeologic report completed for this area in September 2005 (PBSJ, 2005) identified the following strata of geologic formations below the Great Falls area: Madison limestone is the deepest, followed by the Swift Formation, then Morrison sandstone and shale beds, and finally the Kootenai Formation with an upper portion consisting mainly of mudstone and a lower portion consisting of sandstone and siltstone. Unconsolidated sediments extend 125 to 150 feet below ground to the Kootenai Formation. These sediments consist of wind-blown deposits of silty sand, underlain by glacial lake bed and glacial till deposits.

Surface soils at the site consist entirely of Pendroy Clay soils with 2-8% slopes. The Pendroy Clay soils have a fine-grained inorganic clay content of 60-75% down to approximately 40 inches below the surface and a 50-65% clay content at depths between 40 to 70 inches. They exhibit very slow rates of water transmission and infiltration and a high degree of plasticity.

Environmental Consequences

Construction of the facility is expected to last approximately 30 months. The total footprint of the Project would be approximately six acres. Some surface disturbance would occur beyond the plant site with the construction of a transmission line, gas pipeline, and access roads. All, or the majority, of the site would be contoured to an even grade with soil removed from high areas used to fill low areas. Little or no soil stockpiling is expected. Existing aggregate roadways currently leading to the site would be maintained for access during construction. These would be re-graded and paved at the end of the construction period. An 1,800-foot long paved access road into the site would be constructed and maintained from the existing Salem Road. Construction equipment to be used during site development would include bulldozers, backhoes, earth scrapers, motor graders, heavy haul trucks, large tractors, concrete trucks, asphalt pavers, concrete pavers, rollers, and compactors.

Some potential for soil contamination exists during construction and operation due to spills and leaks of fuels and chemicals. Construction equipment may compact soil, reducing its porosity and resulting in a slight increase in the amount of surface runoff in the immediate area. As noted above, the underlying soil in the area has a potential for high runoff and relatively high soil erosion potential. However, this potential is limited by the relatively gentle slopes in the immediate area of the plant site.

SME would be required to obtain a General Permit for Storm Water Discharges Associated with Construction Activities from the Department and either obtain coverage under a General Permit for Storm Water Discharges Associated with Industrial Activity or obtain an individual NPDES permit and would be required to develop a Storm Water Pollution Prevention Plan (SWPPP) for the Project. These documents would identify potential disturbances and the appropriate erosion and sediment control methods to be used to minimize effects. Measures that would be required, such as limiting the area of disturbance and the use of silt-fences, straw mulch, temporary runoff diversions, sediment basins, temporary grading and other methods, would limit short-term erosion. Permit requirements would minimize long-term erosion through requirements for re-grading and re-vegetating as quickly as possible following disturbance. Regular inspections by the Department during and following construction would ensure proper implementation of erosion control techniques. Erosion would be mitigated naturally by the level nature of the Project site and much of the surrounding area.

SME also has stated that it would minimize soil erosion on temporary and permanent roads by use of proper drainage with dips, waterbars, or other methods to prevent water from concentrating on roadways. SME has stated that it would minimize soil compaction by limiting vehicle use to established travel and construction routes and that, if any reclaimed areas became compacted, they would be treated by ripping, plowing, disking, or other appropriate methods prior to re-vegetation of the areas.

Impacts Summary

No significant direct, indirect, or cumulative adverse impacts to the soils, topography or geological resources of the Project area are anticipated as a result of the Project as proposed, including mitigation and monitoring measures. Construction or operation of the Project would not substantially alter the geography or topography of the area, would not result in soil erosion that could cause measurable sediment increases in surrounding surface water, and would not cause widespread soil compaction that would inhibit plant growth. The no-action alternative would not affect this resource in any way.

E. Vegetation Cover, Quantity, and Quality

WESTECH identified several State species of concern that have been observed in the Great Falls area, although not necessarily near the Project site. (WESTECH, 2005). The identified plant species of concern are listed in Table 1.

Table 1. Montana Species of Concern Recorded Within Ten Miles of Great Falls

Species		Suitable Habitat
Common Name	**Scientific Name**	
Plants		
Roundleaf water hyssop	*Bacopa rotundifolia*	Muddy shores of ponds and streams; last recorded in 1891
Many-headed sedge	*Carex sychnocephala*	Moist meadows; lake shores; thickets at low elevations; last recorded in 1890
Chaffweed	*Centunculus minimus*	Drying vernal pools (seasonal wetlands); last recorded in 1891
	Entosthodon rubiginosus	Moss; last recorded in 1887
	Funaria Americana	Moss; last recorded in 1902
Guadalupe water-nymph	*Najas guadalupensis*	Submerged in shallow fresh water of oxbow sloughs and ponds; drying vernal pools; last recorded in 1891
Dwarf woolly heads	*Psilocarphus brevissimus*	Drying vernal pools; last recorded in 1891
California waterwort	*Elatine californica*	Shallow waters and mudflats along the edges of wetlands; last recorded in 1891

Source: Montana Natural Heritage Program, 2005 and USFWS letter dated May 12, 2005.

The amount of wetlands in the area surrounding the Project site is limited. Field surveys and reviews of aerial photographs revealed a few isolated wetlands along Box Elder Creek and the Missouri River (RUS AND MDEQ, 2007a).

Several species of noxious weeds are known to be present in the Great Falls area. These include Canada thistle, field bindweed, whitetop, leafy spurge, spotted knapweed, and Dalmatian toadflax. Only Canada thistle and spotted knapweed are common and widespread, while whitetop and leafy spurge are less abundant. Dalmatian toadflax and field bindweed were not observed near the Project area during biological resources field surveys.

Environmental Consequences

Adverse effects to flora may occur through construction or operation of the facility or infrastructure as described in the EIS (RUS AND MDEQ, 2007a, p. 4-58, et seq.), as well as due to the construction of the gas pipeline. Vegetation can be directly affected by its removal as the ground surface on which it occurs is developed, or indirectly through changing populations of wildlife that feed on plants.

However, as discussed above, the site where the Project would be located currently is entirely cultivated cropland, and the site is surrounded by cultivated cropland, including the NHL, except for coulees within the NHL that are too steep for cultivation. The transmission line would extend along the Salem Road corridor to the south from the HGS facility and then west along the Highway 228 corridor to the Broadview Substation. The gas pipeline would cross under the Missouri River approximately 5 ½ miles west of the HGS facility, extend west across the property to the east of the river, and then cross the National Historic Landmark (NHL) in a northeasterly direction toward the HGS facility.

SME would be required to follow the requirements identified in the Cascade County Weed and Mosquito Management District's document, "Weed Management and Revegetation Requirements for Disturbed Areas in Cascade County, Montana." This document specifies the actions that need to be taken prior to disturbance, during operation, and upon reclamation, to prevent the spread of noxious weeds in the county.

Impacts Summary

Similar to the analysis in the coal facility EIS (RUS AND MDEQ, 2007a), the impacts of the Project on vegetation would be minor. The No Action Alternative would have no direct effects on vegetation at the Project site.

F. Aesthetics

ACOUSTIC ENVIRONMENT

The Project site is located in a rural area approximately eight miles (13 km) east of Great Falls in Cascade County. The surrounding land use is agricultural cultivated cropland with scattered rural residences, most of which are farms. Approximately ten residences are located within three miles of the Project site, and the closest residence is located about 0.5 mile (0.8 km) northwest of the Project site. Primary noise sources include traffic on county roads, farm equipment, noise generated by wind blowing through grass, water flowing in nearby creeks, wildlife, insects, birds, and aircraft flying overhead (BSA, 2007). These noise sources are characteristic of rural settings.

For environmental noise studies, noise levels typically are described using A-weighted equivalent noise levels, Leq, during a certain time period. The Leq metric is useful because it uses a single number to describe the constantly fluctuating instantaneous ambient noise levels at a receptor location during a period of time, and it accounts for all of the noises and quiet periods that occur during that time period.

The 90th percentile-exceeded noise level, L90, is a metric that indicates the single noise level that is exceeded during 90 percent of a measurement period, although the actual instantaneous noise levels fluctuate continuously. The L90 noise level typically is considered the ambient noise level, and often is near the low end of the instantaneous noise levels during a measurement period. It typically does not include the influence of discrete noises of short duration, such as car doors closing, bird chirps, dog barks, car horns, wind gusts, etc.

The day-night average noise level, Ldn, is a single number descriptor that represents the constantly varying sound level during a continuous 24-hour period. The Ldn typically is calculated using 24 consecutive one-hour Leq noise levels. The Ldn includes a 10 dBA penalty that is added to noises that occur during the nighttime hours between 10:00 p.m. and 7:00 a.m., to account for people's higher sensitivity to noise at night when the background noise level typically is low.

As a result of the Noise Control Act of 1972, the U.S. EPA developed acceptable noise levels under various conditions that would protect public health and welfare with an adequate margin of safety. The EPA identified outdoor Ldn noise levels less than or equal to 55 dBA as sufficient to protect public health and welfare in residential areas and other places where quiet is a basis for use (EPA, 1978). Although the EPA guideline is not an enforceable regulation, it is a commonly accepted target noise level for environmental noise studies.

In late August and early September 2005, the acoustical consulting firm Big Sky Acoustics (BSA) conducted ambient (background) noise level measurements at the Project site, in general accordance with the American Society for Testing and Materials (ASTM) E1014, Standard Guide

for Measurement of Outdoor A-weighted Sound Levels (ASTM, 2000). These measurements were taken to establish the typical ambient noise levels within approximately three miles of the Project site where the primary noise-sensitive receptors are located. Short-term measurements of 10-minute duration were conducted at a total of three Project site locations, and the Leq and L90 for each 10- minute period were recorded. BSA completed two continuous 24-hour measurements, and the Leq and L90 in 30- minute increments were also recorded (BSA, 2007). Around the Project site, the L90 ambient short-term noise levels ranged from 20 to 47 dBA, and were influenced by chirping insects as seen in Table 2.

Table 2. Measured Short-term Ambient Noise Levels at the Project Site

Measurement Location	Date and Start Time(hours)	Measured Leq (dBA)	Measured L90 (dBA)	Dominant Noise Sources
1A	8/25/05 at 2151	29	25	Insects
	8/26/05 at 0837	34	31	Insects and wind in grass
	9/01/05 at 1814	48	47	Insects
1B	8/25/05 at 2211	22	20	Insects
	9/01/05 at 1832	46	45	Insects
1C	8/25/05 at 2241	28	23	Insects
	9/01/05 at 1843	47	38	Insects and birds

Source: BSA, 2007

The table does not list farm machinery, which, apparently, was not operating in the vicinity at the time of the study.

BSA also conducted 24-hour measurements to determine the general existing ambient noise level trends throughout the day in the vicinity of the proposed Project site. The 30-minute Leq data were used to calculate the Ldn levels at the measurement locations. The calculated noise levels based on the measurements were Ldn 47 dBA at the Project site (BSA, 2007). Because the measurements were completed in the summer months, insect noise appears to have influenced the measured Ldn values. Based on site observations and the 10-minute measurement results around the site (Table 6-2), the estimated Ldn values during quiet periods would be approximately Ldn 30 dBA at the Project site (BSA, 2007).

Environmental Consequences

Construction-related activities and traffic would result in minor acoustic impacts to the surrounding area, including nearby farms and residences, the Salem Road, and the portion of the NHL near the Project site. Construction of transmission lines and the gas pipeline would also result in minor, short-term, acoustic impacts.

As described above, approximately ten scattered rural residences are located within three miles of the Project site. The closest residence is located approximately one-half mile northwest of the Project site. A Lewis and Clark Staging Area Interpretative Site (Staging Area), which interprets the Great Falls Portage NHL, is located approximately two miles north of the Project site.

To analyze the effects of adding the gas plant to the HGS, along with the coal plant, Big Sky Acoustics (BSA) conducted an additional noise analysis in 2009 (BSA, 2009). The additional noise analysis included addition of a 120-MW natural gas-fired combined cycle power plant to the Project site.

Drawings of the revised Project site and updated equipment lists (Stanley, 2009b), as well as noise level data for the gas turbine model under consideration (General Electric LM6000), a Deltak HRSG, and cooling towers for the HGS gas plant (Stanley, 2009c) were provided to BSA. BSA also used noise data for typical equipment associated with other HGS gas plant noise sources, such as the steam turbine, pumps, transformers, etc., for the analysis (EEI, 1984).

For the analysis, BSA assumed that four wind turbines and the HGS gas plant were operating simultaneously and continuously during a 24-hour period. BSA considered this to be conservative because operation of the wind turbines would have varied with wind speed. Subsequent to BSA's analysis, SME decided not to construct the wind turbines. Therefore, the analysis was even more conservative for the areas that would have been affected by the wind turbines because the analysis included their contributions.

The predicted noise levels for the HGS gas plant and wind turbines are provided in Table 3.

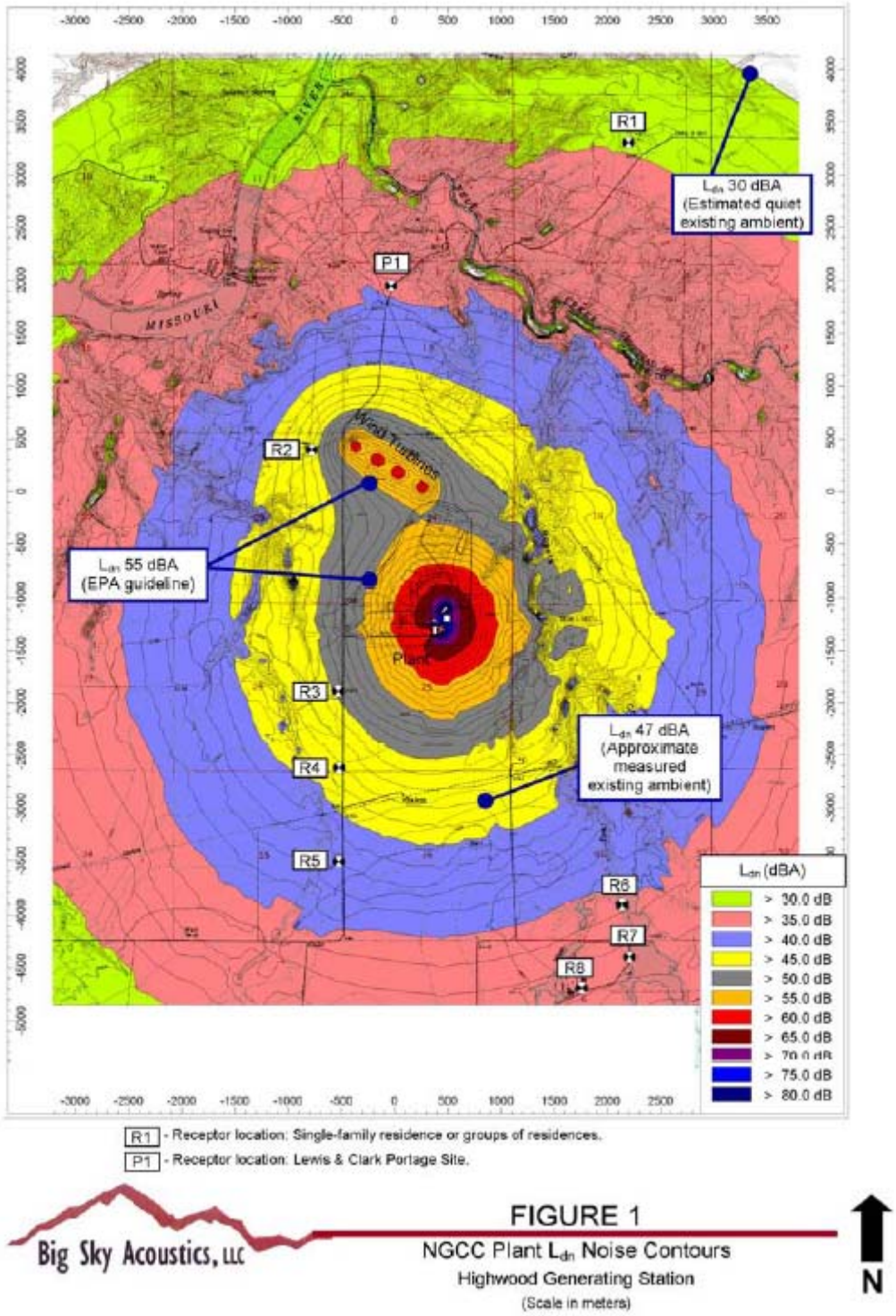
Table 3: Predicted Noise Levels at Nearby Receptors

Receptor Locations	Type of Receptor	Noise Level Leq (dBA)	Noise Level Ldn (dBA)
R1	Single-family residence	28	35
P1	Lewis and Clark Interpretive Site (i.e., Portage Staging Area)	33	39
R2	Single-family residence	43	50
R3	Single-family residence	44	51
R4	Single-family residence	40	47
R5	Single-family residence	37	43
R6	Single-family residence	33	39
R7	Three single-family residences	31	38
R8	Single-family residence	31	37

Source: BSA, 2009

Figure 3 shows the predicted Ldn noise level contours for the HGS gas plant and wind turbines overlaid on a USGS topographic map. As shown in the figure, the noise levels are not predicted to radiate equally in all directions. As shown, the EPA Ldn 55 dBA guideline (EPA, 1978) is predicted to be met within 0.6 mile of the plant location and 0.1 mile of the previously proposed wind turbines. For comparison, according to EPA, the day-night average sound level for a "wooded residential" area is 51 dB, and the day-night average sound level for an "old urban residential area" is 59 dB. (EPA, 1978). The measured existing ambient noise level of Ldn 47 dBA (BSA, 2007) is predicted to be met within approximately 1.2 miles of the plant location and 0.5 mile of the previously analyzed wind turbines. For comparison, the day-night average sound level for "agricultural crop land" is 44 dB. (EPA, 1978). The estimated quiet ambient noise level of Ldn 30 dBA, without the influence of insect noise (BSA, 2007), is predicted to be met within approximately 3.7 miles (Figure 3).

Figure 3. Predicted Noise Levels Contours Surrounding HGS Gas Plant



Source: BSA, 2009

The predicted noise impacts of the HGS gas plant with wind turbines are similar to those from the analysis of the HGS coal plant with wind turbines (BSA, 2007; BSA, 2009). The typical Ldn noise levels are predicted to be less than or equal to the Ldn 55 dBA EPA guideline at identified receptor locations (BSA, 2007; BSA, 2009).

Elimination of the wind turbines from the Project should lessen the noise impacts of the Project to the north and northwest, including the Staging Area Interpretive Site, and the noise levels in those areas should be lower than the noise levels predicted by BSA, as shown above. Elimination of the wind turbines from the Project is not expected to lessen the noise impacts of the Project in other directions, and impacts at receptors in other directions likely would be based on noise from the gas plant.

However, the BSA study demonstrates that predicted impacts would be less than the Ldn 55 dbA EPA guideline level at all receptors representing residences, at the Staging Area Interpretive Site, and at any point along Salem Road. At the Interpretive Site, the only area within the NHL to which the public has access, the predicted noise level is 39 dBA, slightly above the 30 dBA "quiet level" and below the 47 dBA natural background noise level generated by insects and birds.

As discussed above, the area surrounding the Project site consists almost exclusively of privately owned cultivated cropland farms, including most of the NHL. Most of these farms, including those within the NHL, are posted against trespassing, and normal farm machinery operations for growing grain occur on all sides of the Lewis and Clark Staging Area Interpretive Site and on both sides of the road south of that Site past the site of the proposed HGS. Also, a public road runs north and south between the Project site and the Interpretive Site and continues to, and past, that Site.

Any impacts on wildlife would be minor due to the nature of the existing agricultural use in the vicinity of the proposed plant.

Impacts Summary

The typical Ldn noise levels are predicted to be less than or equal to the Ldn 55 dBA EPA guideline at all the receptor locations. The noise levels of typical daily plant operations are not predicted to exceed the EPA guideline of Ldn 55 dBA beyond 0.6 mile from the plant location. The measured existing ambient Ldn level of 47 dBA is expected to be met at a distance of 1.2 miles from the plant location. As a result of these predicted noise levels, the Project is not expected to have a significant adverse impact on receptors where people live or work on the farms in the area or where the public will have access in the surrounding environment, including the Interpretive Site.

In the EIS for the coal plant, the Department and RUS concluded that: " . . . because of NPS policies to preserve the environment of the areas it administers, such as the surrounding Great Falls Portage NHL, at the Salem site, any degradation of the existing natural (or rural) ambient soundscape, such as that represented by HGS construction and operation, would be considered significantly adverse." (RUS and MDEQ, 2007a, EIS, p. 4-77.) The finding of a significant impact was based solely upon the proximity of the NHL to the Project site. Upon further consideration of this categorical conclusion and evaluation of the existing acoustic environment, the Department believes that this determination was incorrect.

The Department is not aware of any basis to characterize any level of additional sound, no matter how insignificant or minor, as causing a significant impact, for purposes of MEPA. Further, the acoustic environment of the NHL does not resemble the environment of the area as it existed at the time of the Lewis and Clark Portage. Numerous cultivated cropland farms, with their attendant noises, are located near and within the NHL, and a public road, with attendant traffic noise, runs through the NHL and into and by the Interpretive Site. All of the NHL near the Project site is posted against trespassing and public access. Therefore, except for the Interpretive Site, the public would observe the NHL in the vicinity of HGS from Salem Road, likely from within a vehicle.

Also, acoustic impacts at the Interpretive Site, which is located two miles from the Project site and which is the only portion of the NHL that is open to the public other than the road right of way, were rated at 33 Leq and 39 Ldn, and these values appear to have been influenced by sound from the four wind turbines, which now will not be constructed, but which were proposed at that time to be located between the gas plant and the Interpretive Site. The acoustic impacts of the gas plant without wind turbines on the portion of the NHL surrounding the proposed site of the wind turbines and on the Staging Area Interpretive Site would be substantially less than the acoustic impacts of the coal plant with the wind turbines.

The Department believes that construction and operation of the Project would have an adverse impact on the acoustic resource of the surrounding rural area. Considering the historical and cultural qualities of the NHL, construction and operation of the Project also would have an adverse impact on the acoustic resource of the NHL near the Project site. However, given that the HSG would be approximately two miles from the Interpretive Site and that areas closer to the HSG are accessible only along Salem Road, the Department believes that the acoustic impact from the Project on the NHL, without the wind turbines, and given the existing development in the area and the level of noise to be expected from that development, would be moderate at most.

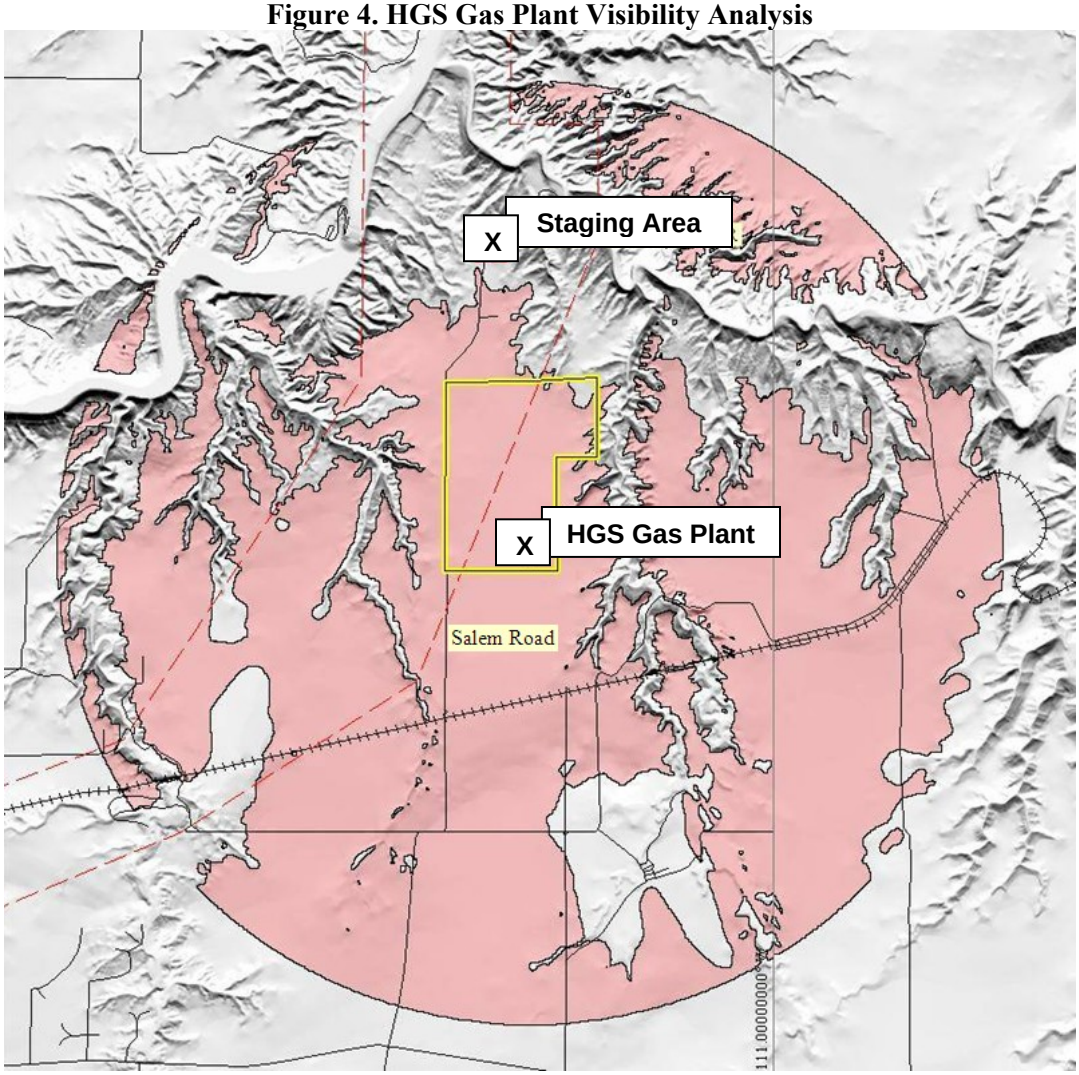
VISUAL RESOURCES

The Project site is characterized by a gently sloping landscape ranging from about 3,260 ft. MSL to about 3,320 ft. MSL. Off-site, this plateau-like landscape is incised by steep-sided coulees or gullies (e.g., Rogers Coulee just to the east of the project site) that cut into the land surface and range from a few feet deep to 100-200 feet deep. The lands on the site itself and in the immediate vicinity are farmed (except for the coulees), with wheat being the dominant crop. The Highwood Mountains are prominently visible to the east at a distance of about 15 miles. Looking toward the south, the Little Belt Mountains, which rise to over 9,000 ft. MSL, also are visible about 30-40 miles away. Looking westward, the front range of the main Rocky Mountains also can be seen on clear days.

The EIS utilized the Visual Resource Management System (VRM) developed by the Bureau of Land Management (BLM) to assess the current visual resources in the vicinity of the Project site (BLM, no date). Although the land in the area of the Project is private land, including the NHL, and the National Park Service administers the Lewis and Clark National Historic Trail and NHL, the Department is not aware of any formal visual resource assessment method other than the BLM method. The VRM assigns a ranking system by rating the visual appeal of a tract of land, measuring public concern for scenic quality, and determining whether the tract of land is visible from travel routes or observation points. Classes I and II are the most valued, Class III represents a moderate value, and Class IV represents the least value. The VRM analysis of the Project site yielded a visual resource ranking of Class III; that is, as possessing moderate visual or scenic values (RUS and MDEQ, 2007a).

Bison Engineering ("Bison") conducted an additional viewshed analysis for a 5 km radius around the HGS gas plant. The radius included the Lewis and Clark Staging Area. This analysis identified areas within the 5 km radius from which a six foot tall observer would be able to see any part of the HGS gas plant, including the 105 ft combined cycle stacks. In Figure 4, the red shaded areas indicate where the HGS gas plant would be visible.

Figure 4. HGS Gas Plant Visibility Analysis



Environmental Consequences

Construction-related activities and traffic would result in minor to moderate visual impacts to the surrounding area, including nearby farms and residences, the Salem Road, and the portion of the NHL near the Project site. Larger construction vehicles would be present on site as well as the emitting units for the Project being assembled.

As seen in Figure 2, the proposed Project would consist of consist of the following main structures: 2 simple cycle combustion turbine generators, each with an 80 foot stack; 2 heat recovery steam generators (HRSG), each with a 105 foot stack; a 70 foot high control/administrative/maintenance activities and steam turbine generator building; a 45 foot high cooling tower structure; and a 30 foot high water treatment building. The viewshed analysis indicates that the HGS gas plant structures would not be visible from the Staging Area, which is two miles away and downslope from the Project site. Some steam plume may be visible in the distance from that point. However, the gas plant would be visible from other portions of the NHL.

The tallest structure would be the 105-foot stacks. The gas plant's footprint and profile would be much smaller than those of the previously proposed coal-fired plant. The tallest structure at the previously proposed coal-fired plant would have been the 400-foot CFB boiler stack. SME no longer intends to construct the previously proposed four wind turbines within the NHL, which

will significantly reduce the visual impacts of the Project in the area and, specifically, will significantly reduce the visual impacts of the Project on the NHL. Much of the visual impact of the coal-fired plant would have resulted from siting the four wind turbines within the NHL and the fact that the top of the 400-foot stack would have been visible from the Interpretive Site. The gas plant still would be visible from various points along Salem Road and from portions of the NHL. However, those portions of the NHL consist of privately owned farms and cultivated cropland and are posted against trespassing and public access. With removal of the wind turbines from the Project, and the decrease in stack height, no part of the Project would be visible from the Staging Area Interpretive Site (Stanley, 2009d), except for any portion of a steam plume that might be visible in the direction of the Project from the Interpretive Site.

The HGS facility would interconnect with existing transmission facilities owned by NorthWestern Energy. The initial interconnection would be with an existing 230 kV line that runs from the Great Falls Substation to the Broadview Substation, near the junction of Salem Road and Highway 228, southwest of the HGS facility. The transmission line from the facility would follow the Salem Road corridor south then follow the Highway 228 corridor west and would not cross the NHL. There are a number of transmission facilities close to the HGS site. If there is a need for future interconnection capacity, and that connection would involve an aerial crossing of the Missouri River, SME would be required to obtain any necessary permits for the crossing at that time. Currently, several transmission lines cross the Missouri River, and SME has stated that it would evaluate connecting with those lines, in determining future interconnection options.

As with the previously proposed coal plant, lighting from the gas plant would be expected to decrease the darkness of the sky in the area at night, although this affect could be reduced with use of downward lighting.

The current view south from the Lewis and Clark Staging Area Interpretive Viewpoint is shown in Figure 5.

Figure 5. Looking South from Lewis and Clark Staging Area Interpretive Site, December 2005

Source: RUS and MDEQ, 2007

As seen in Figure 5, the existing view from the Staging Area Interpretive Site is much changed from the view at the time of the Lewis and Clark Expedition. The photo shows the view to the south-east toward the Project, with existing power poles and a wooden post, barbwire fence around the Interpretive Site. The Interpretive Site, itself, consists of a graveled parking area, interpretive signs, and concrete benches. Although not shown in the photo, farm houses are visible in most directions from the Interpretive Site, and the Interpretive Site is surrounded by cultivated fields. The view to the east includes a house approximately two miles away. The view to the west includes two houses several miles away and two portions of Morony Dam Road. The view to the south includes two existing utility lines, one of which adjoins the road from Belt Creek and extends past the Staging Area and south past the HGS site, a few pieces of old farm machinery in the adjacent field, and a small portion of a petroleum pipeline. The view to the north includes a house approximately 1.5 miles away, another house several miles away, and a power line.

Cascade County zoning regulations require SME to use landscaping to mitigate the visual impacts of the Project. In 2008, SME hired a professional landscape architect, Land Design, Inc. ("Land Design"), to develop a comprehensive landscape plan for the Project site. Land Design developed the landscape plan based on the findings of the EIS (Land Design, 2009) and altered SME's original landscaping plan by substituting more of a scrubland appearance for the original plan to use tall trees. The purpose of this plan is to better blend the landscaping with the surrounding landscape. The plan includes creating earthen mounds around the HGS boundary planted with various trees, shrubs, and grasses. The proposed landscape plan has been approved by Cascade County as part of the location conformance permit required to construct an electrical generating facility at the Project site.

The artist renderings of the proposed landscape plan applied to the gas plant are presented in Figures 6 and 7. The application of the landscaping mitigation measures would substantially reduce visual impacts of the proposed natural gas facility from points of public access.

Previously, to address concerns from historic preservation parties over the potential impact of the coal plant on the aesthetics of the NHL, SME agreed to relocate the HGS coal plant to a site approximately one-half mile south of the originally proposed location and outside the boundary of the NHL.

Figure 6. View of Entry to the HGS Gas Plant

Source: Stanley Consultants, 2009d

Figure 7. View South of the HGS Gas Plant From Salem Road

Source: Stanley Consultants, 2009d

To reduce visual impacts further, SME agreed to use earth tone colors on buildings and transmission towers when designing the coal-fired facility. The design also would maximize the use of directional lighting to reduce the visual impacts at night. These mitigating actions (use of earth tone colors and maximizing directional lighting) would be implemented for the HGS gas plant.

Impacts Summary

In the EIS, RUS and the Department determined that, due to the rural setting and impacts on the NHL, the visual impacts of the previously proposed coal-fired plant, wind turbines, and transmission lines at the Salem site would be "significant and adverse." (RUS and MDEQ, 2007a, EIS, p. 4-95). Upon further evaluation and consideration of the existing development within the NHL, including at the Interpretive Site and surrounding the NHL, the Department now believes that this determination may not have been correct and that visual impacts at this site could have been rated as moderate. However, visual impacts of the current Project would be much less than the visual impacts of the coal plant and wind turbine project, due to elimination of the wind turbines and construction and operation of a much smaller power plant, including much lower 105-foot stacks, rather than the 400-foot stack proposed for the coal-fired plant.

Considering the historical and cultural qualities of the NHL viewshed, the Department believes that construction and operation of the Project, would have an adverse impact on the visual resources of the surrounding rural area, including the NHL, and on the experience of a visitor to the Interpretive Site, as the visitor travels along Salem Road past the Project to the Interpretive Site, and, possibly, from within the Interpretive Site, if steam or the affect of lighting at the plant on the night sky is visible from that location, depending upon the time of day. However, given the relatively small profile of the gas plant and the existing development in the area, including the existing transmission lines, residences, and farmed cropland within the NHL and surrounding the Interpretive Site, the Department believes that the impact of the Project on the visual resources of these areas, including the NHL and Interpretive Site, would be moderate, at most. The No-Action alternative would not impact visual resources and would not require mitigation and monitoring.

G. Air Quality

Project Potential Emissions

The area in which the Project is located is classified as a Prevention of Significant Deterioration (PSD) Class II area (40 CFR 52.1382). The Project and surrounding areas are designated as attainment or unclassifiable in accordance with 42 USC 7407 (d)(1)(A)(ii) and (iii). Accordingly, these areas have been shown or presumed to comply with NAAQS for all pollutants for which such standards have been promulgated.

The Project and surrounding areas also are considered to be in compliance with all MAAQS based on the modeling demonstration that has been conducted. A portion of the City of Great Falls near 10th Avenue South was designated as a non-attainment area for carbon monoxide at one time. The area was re-designated as attainment/unclassifiable in May 2002.

The Federal Clean Air Act (CAA) defines PSD Class I areas as national parks over 6,000 acres, national wilderness areas and national memorial parks over 5,000 acres, and international parks that were in existence as of August 7, 1977. In Montana, three Indian reservations have been redesignated as Class I areas, but are not considered mandatory Federal Class I areas.

The PSD Class I area nearest the Project site is the Gates of the Mountains Wilderness located approximately 88 km from the facility. Five PSD mandatory Federal Class I areas are located within 250 km of the facility and are listed below in Table 4.

Table 4: Mandatory Federal Class I Areas Within 250 km of the Project

Class I Area	Distance from Facility (km)
Gates of the Mountains Wilderness	88
Scapegoat Wilderness	122
Bob Marshall Wilderness	134
Glacier National Park	192
UL Bend National Wildlife Refuge	222

The Project area consists of active dryland farmland. Nearby existing sources of air pollutant emissions primarily are fugitive in nature and include farming related activities, windblown dust from tilled farmland, and road dust from traffic on unpaved county roads.

Significant adverse effects to ambient air quality could occur if air emissions resulted in ground-level pollutant concentrations that exceed national and/or state standards or if the combustion turbine plant operates in a manner that does not comply with air quality permit limits and conditions.

Construction activity air emissions would consist primarily of fugitive particulate emissions resulting from surface grading and vehicular traffic. Temporary localized emissions of gaseous combustion pollutants (i.e. exhaust) also would result from construction-related traffic and miscellaneous activities. All construction-related air emissions would be intermittent, of limited duration, and similar with respect to air emissions that normally occur in the area.

Because the proposed facility's combustion turbines would use natural gas fuel that would be transported by pipeline to the facility, and because the environmental controls proposed do not require large quantities of solid materials to function, vehicle and fugitive dust emissions are expected to be minor during operation of the plant.

The Project would be constructed in two phases. Phase I of construction would include installation of two simple cycle combustion turbines, with all support equipment and structures, including the simple cycle stacks. Support equipment at the facility would include an emergency diesel generator, a fire pump, and building heaters. Phase II construction would include installation of two HRSGs, emissions control equipment, a steam turbine, and combined cycle exhaust stacks. During both the initial Phase I period of simple cycle operation and the Phase II operation after steam plant installation, simple cycle hours of operation would be limited to 3,200 hours per year. Combined cycle operation hours would not be limited.

The natural gas-fired combustion turbines would be the largest sources of air emissions associated with the Project. The gas-fired turbines would have the potential to emit the following criteria pollutants (pollutants for which National Ambient Air Quality Standards (NAAQS) have been established): NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, and Pb. Other point sources of air pollutant emissions include the cooling towers and the emergency generator. Table 5 presents estimated potential annual emissions of criteria pollutants from the facility.

Table 5. Facility Annual Potential to Emit Summary

Source	Annual Emissions (TPY)						
	PM	**PM_{10}**	**$PM_{2.5}$**	**NO_x**	**CO**	**VOC**	**SO_2**
Turbine East	31.54	31.54	31.54	89.11	244.08	11.41	3.02
Turbine West	31.54	31.54	31.54	89.11	244.08	11.41	3.02
Emergency Generator	0.04	0.04	0.04	6.04	0.55	0.13	0.09
Fire Pump Engine	0.04	0.04	0.04	1.02	0.24	0.04	0.02
Cooling Towers	1.14	1.14	1.14	--	--	--	--
Building Heaters	0.09	0.09	0.09	1.68	1.01	0.07	0.01
Haul Roads	5.68	1.57	--	--	--	--	--
Total	70.07	65.96	64.39	186.96	489.96	23.06	6.16

In addition to the criteria pollutants addressed above, the Federal and Montana Clean Air Acts specifically regulate hazardous air pollutants (HAPs), including 189 individual compounds or groups of compounds. Table 6 presents a summary of potential HAP emissions from the Project. The Project would be classified as an area (or non-major) source of HAP emissions, according to CAA definitions.

Table 6. Hazardous Air Pollutants Emission Inventory (TPY)

Hazardous Air Pollutant	**CAS Number**	**Turbines [1]**	**Black Start Generator [2]**	**Fire Pump [3]**	**Total Facility**
Organic HAPs					
1,3-Butadiene	106-99-0	0.002	0.0E+00	2.45E-05	0.002
Acetaldeyde	75-07-0	0.157	9.2E-05	4.81E-04	0.157
Acrolein	107-02-8	0.025	2.9E-05	5.80E-05	0.025
Benzene	71-43-2	0.047	2.8E-03	5.85E-04	0.050
Ethyl benzene	100-41-4	0.125	0.00	0.00	0.125
Formaldehyde	50-00-0	2.783	2.9E-02	7.40E-04	2.813
Naphthalene	91-20-3	0.005	4.7E-04	5.32E-05	0.006
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	0.009	7.7E-04	1.05E-04	0.010
Propylene Oxide	75-56-9	0.114	1.0E-02	1.62E-03	0.125
Toluene	108-88-3	0.510	1.0E-03	2.57E-04	0.511
Xylenes	1330-20-7	0.251	7.0E-04	1.79E-04	0.252
Total Organic HAPs		**4.03**	**0.045**	**0.004**	**4.08**
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	0.00
Total Inorganic HAPs		**0.00**	**0.00**	**0.00**	**0.00**
Total Calculated Maximum Potential HAP Emissions		**4.03**	**0.045**	**0.004**	**4.08**

1. Turbine emission factors obtained from AP-42, Tables 3.1-2a and 3.1-3; calculations assume worst case operation, i.e., two turbines operating in combined cycle mode with duct firing for 8,760 hours per year.
2. Generator emission factors obtained from AP-42, Tables 3.4-3 and 3.4-4; calculations assume 500 hours of operation per year.
3. Fire pump emission factors obtained from AP-42, Table 3.3-2; calculations assume 500 hours of operation per year.

Based on estimated actual operation, the facility would emit roughly 250,000 tons of CO_2 per year, assuming two General Electric LM-6000PF combustion turbines operate for 4,380 hours, at 91.5^o F, and 100% load, with duct burners running. Calculations are based on the emission factor for the duct burners from the US EPA publication AP-42, Table 1.4-2, and the emission factor for the turbines is from GE. Based on 8,760 hours of operation per year, the facility would emit roughly 500,000 tons of CO_2 per year. This compares to an estimated 2.1 million tons of CO_2 per year that would have been emitted by the previously proposed coal-fired plant (RUS and MDEQ, 2007a). Also, the estimated CO_2 emissions from the recently permitted Basin Electric Power Cooperative 100 MW simple cycle natural gas power plant facility would be 147,600 tons per year.

Impacts Analysis

Estimated air quality impacts were determined for the area immediately surrounding the Project site, all of which is designated as a PSD Class II area, and for locations distant from the proposed site that are designated as PSD Class I areas. Air dispersion models were used to perform the analyses. These models use hourly meteorological data, terrain elevation data, and emission source data to calculate ground-level pollutant concentrations that would result in the Project's worst-case emissions at a set of defined locations. These pollutant concentrations are then measured against established thresholds to determine impacts and regulatory compliance from the Project. Conditions for both Phase I and Phase II operating scenarios were modeled.

As part of the MAQP application #4429-00, SME submitted a modeling analysis of ambient air quality dispersion. Bison provided the modeling demonstrations on behalf of SME. When SME submitted the modeling demonstration, the SME property upon which the Project is to be constructed was also permitted for the HGS coal plant (MAQP #3423-01). The modeling demonstration that SME submitted for the Project analyzed combined worst case emissions from both the HGS coal plant and the HGS gas plant as if emissions from each facility were to occur simultaneously. This worst case analysis demonstrated compliance with Montana Ambient Air Quality Standards (MAAQS), NAAQS, and PSD Class II and Class I increments.

If emissions of a particular pollutant from a facility would result in a peak concentration over a specific averaging period that is below a related modeling significance threshold, then that source is considered incapable of contributing to a violation of an air quality standard or increment limit. In other words, the source's impacts on ambient concentrations of that pollutant for that averaging period are deemed to be "insignificant."

The Project's impacts to Class II area ambient concentrations of SO_2 and CO for all regulated averaging periods were shown through modeling to be insignificant, and no further analyses were performed for these pollutants. Further analyses of impacts to Class II area ambient concentrations of NO_x, PM_{10}, and $PM_{2.5}$ were conducted below. Table 7 summarizes the pollutants analyzed and the results of the significant impact levels.

Table 7. Significance Impact Levels

Pollutant	Averaging Period	Significance Level ($\mu g/m^3$)	Modeled Concentration ($\mu g/m^3$)	Significant Impact?
$PM_{2.5}$	24-Hour	1.2	6.83	YES
	Annual	0.3	0.79	YES
PM_{10}	24-Hour	5	6.83	YES
	Annual	1	0.79	NO
NOx	Annual	1	3.50	YES
SO_2	1-Hour	25	7.9	NO
	3-Hour	25	5.18	NO
	24-Hour	5	2.07	NO
	Annual	1	0.09	NO
CO	1-Hour	2,000	328.60	NO
	8-Hour	500	112.53	NO

The PSD permitting program requires an analysis to assess impacts to Class I areas. The PSD permitting program establishes PSD increments, which are maximum allowable increases in air contaminant concentrations in attainment or unclassified areas. PSD increments have been established for PM_{10}, SO_2, and NO_x. No increments have been established for $PM_{2.5}$. Unique Class I area impact limits are specified for NO_x and PM_{10} ambient concentrations. Modeling analyses demonstrated that the Project's NO_x and PM_{10} emissions would result in "insignificant" impacts to ambient concentrations in all surrounding Class I areas. The following tables (Tables 8 and 9) summarize the modeling analysis demonstration.

Table 8. Maximum Class I PSD Increments for Steady State Conditions.

Pollutant	Averaging Period	Class I Wilderness Area	Modeled Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
PM_{10}	24-Hour	Gates of the Mountains	0.03467	8	0.3
	Annual	UL Bend	0.00142	4	0.2
NO_2	Annual	Gates of the Mountains	0.00254	2.5	0.1

Table 9. Maximum Class I PSD Increments for Startup/Shutdown Conditions.

Pollutant	Averaging Period	Class I Wilderness Area	Modeled Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
PM_{10}	24-Hour	Gates of the Mountains	0.03512	8	0.3
	Annual	UL Bend	0.00144	4	0.2
NO_2	Annual	UL Bend	0.00262	2.5	0.1

Impacts to ambient concentrations of VOC and lead were not evaluated for this project. As shown in Table 6, lead emissions are expected to be negligible. VOC emissions are considered to be insignificant and alone would be considered below the minor source permitting threshold.

The $PM_{2.5}$, PM_{10}, and NO_x NAAQS/MAAQS analyses used the maximum emission rates from the HGS coal and gas plants, and all of the off-site surrounding facilities. Table 10 compares modeled peak concentrations of NO_x, PM_{10}, and $PM_{2.5}$ with the appropriate MAAQS and NAAQS. Note that the modeled concentrations shown in Table 10 include background

concentrations and concentration impacts resulting from potential emissions of other permitted facilities in the region. As shown, the Project would not result in a violation of any ambient air quality standards.

Table 10: Ambient Air Quality Analyses

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)	Modeled Concentration ($\mu g/m^3$)
$PM_{2.5}$	24-Hour	35	NA	24
	Annual	15.0	NA	7.9
PM_{10}	24-Hour	150	NA	34
NO_x	1-Hour	NA	564	312
	Annual	100	94	10

Note: SO_2 and CO were found to be insignificant and were not carried through in the modeling analysis.

The Project is required to demonstrate compliance with Class II increments for NO_x and PM_{10} with SO_2 concentrations below the significance level. As a conservative approach to the Class II PSD increment analysis, potential emissions of PM_{10} and NO_x which were modeled concentrations derived from the NAAQS/MAAQS analyses were used rather than the required latest two-year average of actual emissions. The results of the Class II PSD increment analysis using potential emission are provided in Table 11. No increments were exceeded in this Class II modeling analysis.

Table 11. PM_{10} and NO_x Class II PSD Increment Analysis.

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
PM_{10}	24-Hour	11	30
NO_x	Annual	4	25

The PSD program requires evaluation of impacts on air quality related values, including visibility, in mandatory Federal Class I areas. A Class I significant impact analysis was performed to identify the potential impacts from the proposed emissions increase from the HGS gas plant. The predicted impacts were well below the significance levels for Class I areas so no further analysis was necessary. The data are summarized above in Tables 12 and 13 demonstrating the predicted Class I impacts.

Table 12. Maximum Class I PSD Increments for Steady State Conditions.

Class I Area	Pollutant	Averaging Period	Predicted Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
Gates of the Mountains WA	PM_{10}	24-Hour	0.03467	8	0.3
UL Bend WA		Annual	0.00142	4	0.2
Gates of the Mountains WA	NO_2	Annual	0.00254	2.5	0.1
	SO_2	3-Hour	0.01042	25	1.0
		24-Hour	0.00238	5	0.2
UL Bend WA		Annual	0.00010	2	0.1

Table 13. Maximum Class I PSD Increments for Startup/Shutdown Conditions.

Class I Area	Pollutant	Averaging Period	Predicted Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
Gates of the Mountains WA	PM_{10}	24-Hour	0.03512	8	0.3
UL Bend WA		Annual	0.00144	4	0.2
	NO_2	Annual	0.00262	2.5	0.1
Gates of the Mountains WA	SO_2	3-Hour	0.01037	25	1.0
		24-Hour	0.00241	5	0.2
UL Bend WA		Annual	0.00010	2	0.1

Impacts to natural background visibility are expressed in terms of percentage change in background light extinction averaged over a 24-hour period. The Federal Land Manager Air Quality Related Values Workgroup (FLAG document) guidance suggests that a predicted change in extinction of less than 0.5 deciview, resulting from a single source, generally should be acceptable. A predicted change in extinction between 0.5 and 1.0 may warrant a cumulative analysis that includes impacts from certain other nearby sources. A change in 0.5 deciviews is essentially equivalent to a 5% change. The NPS considers a change greater than or equal to 5% in any one met year a violation and refined analysis would be required including the emissions from the near-by industrial sources.

Simple Cycle turbine emissions had the greatest effect on the natural background visibilities at all of the Class I areas, probably due to the higher NO_x emission rates. However, none of the values exceeded the threshold of 0.5 dv change at any Class I area. The maximum 24-hour change in visibility from natural background conditions was 0.107 dv at the UL Bend Wilderness Area from the HGS gas plant Simple Cycle turbine emissions, under startup/shutdown conditions.

The PSD program also requires evaluation of acid deposition in mandatory Federal Class I areas. The HGS gas plant emissions were included in this modeling phase. The FLAG document provided guidance for evaluating rates of acid deposition, within Class I areas, resulting from a proposed new or modified facility. Following guideline analysis methods, acid deposition rates

resulting from the Project's potential emissions would be far below the guideline threshold of 0.0050 kilograms per hectare per year in each of the surrounding Class I areas. Tables 14 and 15 list the results for both steady state and startup/shutdown conditions, respectively.

Table 14. Maximum Deposition for Steady State Conditions.

Class I Area	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Bob Marshall WA	2.09E-04	1.17E-05
Gates of the Mountains WA	1.01E-03	4.57E-05
Glacier NP	7.99E-05	5.27E-06
Scapegoat WA	3.12E-04	1.85E-05
UL Bend WA	5.57E-04	3.03E-05

Table 15. Maximum Deposition for Startup/Shutdown Conditions.

Class I Area	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Bob Marshall WA	2.10E-04	1.13E-05
Gates of the Mountains WA	9.55E-04	4.53E-05
Glacier NP	8.55E-05	5.23E-06
Scapegoat WA	3.01E-04	1.82E-05
UL Bend WA	6.06E-04	3.05E-05

MAQP Summary

Pursuant to ARM 17.8.308, SME would be required to take reasonable precautions to control emissions of airborne particulate matter. SME and its contractors would use best management practices to limit fugitive dust during construction and operation of the Project. These practices could include; applying water and/or dust suppression chemicals to roadways and disturbed surfaces, as needed; ensuring that its contractors and employees observe speed limits on access roads; and reseeding or otherwise stabilize disturbed areas.

Montana air quality rules require that a best available control technology (BACT) analysis be completed and the determinations will require mechanisms control emissions from the proposed facility. By definition, BACT is determined on a case-by-case basis. For this Project, the Department has determined the following controls are BACT for controlling emissions from the combustion turbine in simple cycle mode and combined cycle mode and from the emergency generator and emergency fire water pump.

Table 16. Simple Cycle Mode

Pollutant	BACT
NO_x	Dry low NO_x Burners (DLN) and fuel selection. For simple cycle, NO_x control is cost-prohibitive above the baseline of fuel selection and DLN.
CO and VOC	Proper system design and operation. Add-on controls are not cost-effective.
SO_2	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.
$PM/PM_{10}/PM_{2.5}$	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.

Table 17. Combined Cycle Mode

Pollutant	BACT
NO_x	DLN, Selective Catalytic Reduction (SCR), and fuel selection.
CO and VOC	Catalytic oxidation.
SO_2	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.
$PM/PM_{10}/PM_{2.5}$	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.

Table 18. Emergency Generator and Emergency Fire Water Pump

Pollutant	BACT
NO_x	Proper design and operation. Operate only in emergencies and for required maintenance. Permit limit of 500 hours per year per engine.
CO and VOC	
SO_2	
$PM/PM_{10}/PM_{2.5}$	

Compliance assurance monitoring (CAM) requirements are pollutant-specific and apply to certain emissions units at a facility for which a Title V air quality operating permit is required. SME would be required to obtain an operating permit for the generation facility, but only the natural gas combustion turbines would meet the CAM applicability criteria, and the criteria would apply only to NO_x and CO emissions. The applicability of the CAM requirements is determined in accordance with ARM 17.8 subchapter 15**.** SME will be required to provide the Department with a formal CAM plan when applying for their operating permit. NO_x emissions would be monitored and recorded using a continuous emissions monitoring system which will not only be a requirements of the operating permit, but is also a requirements of MAQP #4429-00.

Impacts Summary

In its air quality permit application for the Project, SME demonstrated compliance with all applicable ambient air quality regulatory and guideline limits, including ambient standards, PSD increments, and visibility and acid deposition impact guidelines. SME would be required to obtain air quality construction and operating permits and comply with all permit requirements including testing, monitoring, and reporting requirements.

Based on the analyzes conducted and the information contained above and within MAQP #4429-00 the impacts to air quality from the Project would be considered minor. The no-action alternative would not affect air quality in the Great Falls area.

H. Unique Endangered, Fragile, or Limited Environmental Resources

State Species of Concern

WESTECH researched previously recorded wildlife sightings within a ten mile radius of the Project site and areas surrounding the proposed transmission lines (WESTECH, 2005). The research included interviews with landowners and with specialists from the FWP. This research identified several State species of concern that have been observed in the Great Falls area. The Department also conducted a species of concern search through the Montana Natural Heritage Program. The identified species of concern are listed in Table 19.

Table 19. Montana Species of Concern Recorded Within Ten Miles of Great Falls [1]

Species		Suitable Habitat
Common Name	**Scientific Name**	
Plants		
Roundleaf water hyssop	*Bacopa rotundifolia*	Muddy shores of ponds and streams; last recorded in 1891
Many-headed sedge	*Carex sychnocephala*	Moist meadows; lake shores; thickets at low elevations; last recorded in 1890
Chaffweed	*Centunculus minimus*	Drying vernal pools (seasonal wetlands); last recorded in 1891
	Entosthodon rubiginosus	Moss; last recorded in 1887
	Funaria Americana	Moss; last recorded in 1902
Guadalupe water-nymph	*Najas guadalupensis*	Submerged in shallow fresh water of oxbow sloughs and ponds; drying vernal pools; last recorded in 1891
Dwarf woolly heads	*Psilocarphus brevissimus*	Drying vernal pools; last recorded in 1891
California waterwort	*Elatine californica*	Shallow waters and mudflats along the edges of wetlands; last recorded in 1891
Fish		
Blue sucker	*Cycleptus elongates*	Missouri River below Morony Dam
Sauger	*Sander Canadensis*	Missouri River below Morony Dam
Amphibians – none		
Reptiles		
Spiny softshell turtle	*Apalone spinifera*	Missouri River below Morony Dam
Greater short-horned lizard	*Phrynosoma hernandesi*	Missouri River below Morony Dam
Mammals – none		
Birds		
Ferruginous hawk	*Buteo regalis*	Sagebrush steppe, grasslands with rolling to steep slopes
Bald eagle [2]	*Haliaeetus leucocephalus*	Larger rivers, lakes and Reservoirs
Burrowing owl	*Athene cunicularia*	Grasslands with rodent and badger burrows
White-faced ibis	*Plegadis chihi*	Wetlands
Black-crowned night heron	*Nycticorax nycticorax*	Wetlands
Franklin's gull	*Larus pipixcan*	Wetlands
Common tern	*Sterna hirundo*	Wetlands
Black tern	*Chlidonias niger*	Wetlands

1. Source: MNHP, 2005 and USFWS letter dated May 12, 2005.
2. Bald eagles were removed from the endangered species list in June 2007.

The blue sucker, sauger, and spiny softshell turtle are known to be present below Morony Dam (WESTECH, 2006a). The dams along the Missouri River likely have restricted the movement of these species (RUS and MDEQ, 2007a). Avian species of concern potentially in the Project area include ferruginous hawks, burrowing owls, whitefaced ibis, black-crowned night heron, Franklin's gull, common tern, and black tern. Only the Franklin's gull was observed during 2005 surveys (WESTECH, 2005).

A bald eagle nest is located near the confluence of the Missouri River and Belt Creek (Dubois, 2005; WESTECH, 2005). The site is approximately two miles from the generation facility site. The nest was active in 2005 and produced one fledgling (Taylor, 2005; WESTECH, 2005). No other bald eagle nests are known to be in the area (Taylor, 2005; WESTECH, 2005).

Wetlands and Noxious Weeds

The amount of wetlands in the area surrounding the Project site is limited. Field surveys and reviews of aerial photographs revealed a few isolated wetlands along Box Elder Creek and the Missouri River (RUS AND MDEQ, 2007a).

Several species of noxious weeds are known to be present in the Great Falls area. These include Canada thistle, whitetop, leafy spurge, and spotted knapweed. Only Canada thistle and spotted knapweed are common and widespread, while whitetop and leafy spurge are less abundant.

Environmental Consequences

Adverse effects to flora and fauna may occur through construction or operation of the facility or infrastructure as described in the coal-fired generation facility EIS (RUS AND MDEQ, 2007a). Wildlife could experience mortality directly due to construction or operation of the facility or its infrastructure, or indirectly through habitat loss, fragmentation, or conversion. Vegetation can be directly affected by its removal as the ground surface on which it occurs is developed, or indirectly through changing populations of wildlife that feed on plants.

SME would be required to follow the requirements in the Cascade County Weed and Mosquito Management District's document, "Weed Management and Revegetation Requirements for Disturbed Areas in Cascade County, Montana." This document specifies the actions that need to be taken prior to disturbance, during operation, and upon reclamation, to prevent the spread of noxious weeds in the county.

The Montana Bald Eagle Management Plan limits high intensity activities in areas requiring special protection for bald eagle nests. Construction contractors would be required to conduct activities, such as developing aggregate sources, gravel crushing, staging and stockpiling, well outside of areas requiring special protection for bald eagle nests along the Missouri River. Any questions SME or its contractors have concerning application of requirements intended to protect this species should be directed to the USFWS and/or FWP.

Impacts Summary

Similar to the impacts of constructing and operating the coal facility (RUS AND MDEQ, 2007a), the biological impacts of constructing and operating the gas plant Project would be minor. The No Action Alternative would have no direct effects on biological resources at the Project site.

I. Demands on Environmental Resource of Water, Air and Energy

As described in Section 7.B of this EA, impacts to area water resources would be minor because the demands for water would be relatively low and the resulting amount of wastewater generated would be small. Also, SME is not proposing to directly discharge any material to surface or ground water resources in the area. Wastewater would be discharged to the City of Great Falls wastewater treatment facility or treated and evaporated onsite, as discussed above.

As described in Section 7.G of this EA, any impact to the air resource in the area of the facility would be minor. MAQP #4429-00 would contain conditions limiting the emissions from the facility. Air emissions from the facility would be controlled and relatively low due to the

dispersion characteristics of the facility and local area. Dispersion modeling of worst case conditions (including operation of the HGS coal plant, for which MAQP #3423-01 has since been revoked) demonstrated that emissions from the proposed facility would not cause exceedances of ambient air quality standards, PSD increments, or guidelines intended to protect air quality related values in mandatory Federal Class I areas.

Impacts to energy resources would result from increased access to natural gas as a result of gas pipeline installation. Impacts to energy would also result from the consumption of natural gas to power the combustion turbine generator and building heaters, and from consumption of diesel fuel to power the emergency generator and fire pump. Total facility energy consumption would be 7,873,268 MMBtu/yr, with turbines and buildings operating 8,760 hours per year, and the emergency generator and fire pump each operating 500 hours per year. The Project would have a maximum heat input of approximately 7,840,000 MMBtu/year, assuming 8,760 hours of operation per year. This would compare to a maximum heat input of approximately 192,500,000 MMBtu/year for the PPL Colstrip Steam Electric Station Units 1-4.

J. Historical and Archaeological Sites

As part of the EIS for the coal-fired facility, archaeologists conducted a records search for previously recorded cultural resource sites within the general vicinity of the Project site (Dickerson, 2005). Records from the Montana State Historic Preservation Office (SHPO) records center and the cultural resource site files at the Department of Anthropology, University of Montana, Missoula, were reviewed.

A professional archaeologist at Renewable Technologies, Inc. (RTI) completed a cultural resource inventory of the HGS site in 2005 (Dickerson, 2005). The inventory encompassed a total of 1,180 acres, covering the proposed HGS plant site and various infrastructure corridors. Because the natural gas plant footprint would be materially smaller in magnitude and fit within the overall footprint of the previously proposed coal-fired HGS, pertinent inventories are carried forward into this assessment for the natural gas-fired facility.

Ten cultural properties were found to lie within the area of potential effect of SME's HGS site. The ten cultural properties include five previously recorded sites, and five sites discovered and recorded as part of the project (Dickerson, 2005). For nine of the ten sites, the sites were fully recorded or site records were amended. One newly discovered farmstead (field number RTI-05025-04) was identified but not fully documented due to lack of access to the property. Table 20 lists the ten sites documented within the Project area. Detailed descriptions and record forms for each site are contained in the RTI report (Dickerson, 2005).

Table 20. Cultural Sites Documented Within SME's Project Area

Site Number	Description	Legal Location*	National Register Eligibility/Status
24CA238	Great Falls Portage National Historic Landmark	T20N, R5E, Secs 3-7; T21N, R5E, Secs 13-14, 23-27, 33-35	Listed, National Historic Landmark
24CA264	Chicago, Milwaukee, St. Paul & Pacific Railroad	T20N, R4E, Sec 1; T20N, R5E, Secs 5, 6; T21N, R5E, Secs 32-35	Eligible; portion lying within SME's project area is a contributing element
24CA289 Feature 2	Morony Transmission Line	T21N, R4E, Secs 24-26	Contributing Element of an Eligible District
24CA291 Feature 34	Rainbow Transmission Line	T21N, R4E, Secs 24-26	Contributing Element of an Eligible District
24CA416	Rainbow-Ryan Road	T21N, R4E, Secs 25, 26; T21N, R5E, Sec 19	Eligible
24CA986	Historic Farmstead	T21N, R5E, Sec 23	Ineligible
24CA987	Historic Farmstead	T21N, R5E, Sec 26	Ineligible
24CA988	Historic Farmstead	T21N, R5E, Sec 26	Ineligible
24CA989	Cooper Siding	T20N, R5E, Sec 6	Ineligible
RTI-05025-4	Historic Farmstead	T21N, R5E, Sec 35	Unevaluated; presumed ineligible**

Source: Dickerson, 2005
* The legal locations listed above encompass only those portions of sites situated within SME's project area.
** Property RTI-05025-4 was noted in the field, but not formally recorded or evaluated for National Register eligibility.

Great Falls Portage National Historic Landmark (24CA238)

The Great Falls Portage NHL (24CA238) is a historic landscape area associated with the portage of the Lewis and Clark Corps of Discovery around the Great Falls of the Missouri River in 1805. The site first was recorded in 1976, with revisions to the National Landmark nomination form in 1984 (Witherell, 1984). The Great Falls Portage NHL is an approximately one-mile wide discontinuous corridor spanning from the lower portage camp, located immediately north of the mouth of Belt Creek, to White Bear Island at the southern outskirts of Great Falls. RTI's 2005 inventory covered portions of the northern section of the NHL corridor extending northeast from the eastern boundary of Malmstrom Air Force Base. Within the inventory project area, RTI found no physical evidence of the Corps of Discovery's portage activities. No camp features, artifacts, or similar evidence were found on the surface. Currently, ownership of the property within the NHL is held by SME and other neighboring landowners.

Environmental Consequences

On January 20, 2006, RUS sent letters to eight organizations in the Montana-Wyoming Tribal Leaders Council informing them of the HGS proposal and EIS process and inviting comment and participation. By way of this letter, RUS formally requested consultation with the tribes on SME's proposal. RUS also asked tribal representatives to advise RUS if they had specific concerns regarding either of the proposed locations of the HGS, and in particular, asked for any information they may have on the possible presence of Traditional Cultural Properties (TCPs) or sacred sites at either of the proposed locations under study.

Two responses were received from tribes to this request for consultation. The Northern Cheyenne Tribe expressed concern about cumulative air quality impacts and asked to receive the Draft EIS. The Blackfeet Tribal Historic Preservation Office requested a site visit, which was held on March 24, 2006. To date, no TCPs have been identified at the Project site.

As described above, ten cultural properties are found in the vicinity of the Project. The ten include five previously recorded sites, and five discovered and recorded as part of investigations supporting the EIS. Of these ten properties, only the Great Falls Portage NHL (24CA238) would be impacted by the proposed Project.

In 2007, the National Park Service issued a report regarding an evaluation of the impacts of the previously proposed HGS coal-fired plant on the NHL (NPS, 2007). In the report, the NPS concluded that construction and operation of the HGS would have significant and adverse impacts to the Lewis and Clark National Historic Trail and could result in de-listing of most, if not all, of the NHL. Although the NPS clearly opposes construction of any power plant at the Salem site, the conclusions in the NPS report were based, in large part, on SME's proposal at that time to construct four 300-foot tall wind turbines and an electrical transmission line within the NHL and to construct a coal-fired power plant with a 400-foot stack. As discussed above, SME has modified its proposal since issuance of this report. SME does not intend to construct the wind turbines, only one electrical transmission line is proposed, and that line would not cross the NHL.

Because potential RUS funding was involved in SME's proposal to construct a coal-fired power plant at the HGS site, the finding in the coal plant EIS of an adverse impact on the NHL triggered a requirement, under Section 106 of the National Historic Preservation Act, for a consultation between parties interested in the NHL. RUS initiated, but did not complete, a Section 106 consultation with interested parties, including the State Historic Preservation Office (SHPO), the National Park Service, the Advisory Council on Historic Preservation, and other local and national groups. Before the consultation process concluded, potential RUS funding for the project was eliminated as part of a general curtailment of RUS funding for coal-fired electrical generation facilities. With elimination of RUS involvement in the Project, in 2008, the U.S. Army Corps of Engineers ("Corps") assumed the role of completing the Section 106 consultation process. In March 2009, the Corps held a meeting with involved parties, received follow-up comments from meeting participants, toured the site, and requested additional information from SME. At the time the Corps engaged in these activities, the air quality permit for the previously proposed coal-fired plant still was valid and the parties viewed the proposed gas plant as an additional action at the site.

Because revocation of the air quality permit for the coal plant eliminated the potential impacts of that facility on the NHL, the scope of the Section 106 consultation process has changed. The Corps has requested that SME submit a new application for any Section 10 or Section 404 permits that may be necessary for the gas-fired plant Project. The Corps withdrew its request for Section 106 consultation in a letter to the Advisory Council on Historic Preservation (dated September 22, 2009). In the letter, the Corp states that it received a request to withdraw SME's existing permit request for the coal-fired facility, and in a letter dated September 10, 2009, the Corps withdrew SME's original application that had been submitted April 16, 2008. The Corps' September 2009 letter continues, stating that SME has submitted a new application on September 3, 2009, for a natural gas-fired combined cycle generating facility, and "Under this revised proposal, the only activity regulated by the Corps will be an aerial crossing of the Missouri River by a redundant 230 KV electric transmission line," which will cross the river approximately 7 miles west of the boundary of the Lewis & Clark Great Falls Portage National Historic Landmark. The letter concludes, "Our evaluation of the new permit application led to a determination that the Corps lacks sufficient Federal control or responsibility under Section 10 to expand its analysis to include activities undertaken outside waters of the United States," and "Consequently, the Corps analyses under NEPA and NHPA will address only the revised project's construction of the 230kv aerial transmission lines across the Missouri River and the towers immediately supporting the transmission line crossing."

The NHL's integrity is based predominantly on visual landscape qualities that are reportedly similar to those that existed during the early 19th century when the Corps of Discovery traveled through the area. While portions of the visual landscape qualities of the Great Falls Portage NHL

are similar to those that existed at the time of the Lewis and Clark expedition, other portions are not. The NHL is privately owned and is posted against trespassing and public access in the vicinity of the Project. The view of the NHL from the only public access points in the area of the Project, Salem Road, and the Staging Area Interpretive Site, is largely of cultivated cropland. The view also includes existing power lines and farm houses. From the Interpretive site, a portion of the Morony Dam Road also is visible, as are some old farm equipment and a small above-ground portion of a petroleum pipeline. In the greater area of the NHL, the visual landscape also is quite changed, including damming of the Great Falls of the Missouri, development of the City of Great Falls, development of Malmstrom Air Force Base, development of numerous farmsteads and accompanying facilities, residential and commercial development, and installation of numerous transmission lines across the Missouri River.

In the Draft EIS, RUS and the Department found a significant adverse effect to the NHL if SME were to proceed with the development of a coal-fired generating station located on the NHL. As explained below, SME proposed mitigation measures, including shifting the coal plant site off the NHL. In the Final EIS, RUS and the Department also found a significant adverse effect, although noting the reduction of impacts resulting from mitigation.

As discussed above, the proposed natural gas-fired generation facility would have a much smaller profile than the previously proposed coal-fired plant and would not be visible from the Staging Area Interpretive Site, except for any steam that might be visible from that site. Construction and installation of the transmission lines and gas pipeline across the NHL may have minor, short-term impacts.

Mitigation

SME proposed, and RUS agreed with, proposed mitigation measures for the HGS coal-fired power plant and wind turbine project. Many of these proposals were completed or contemplated by SME in designing the coal-fired project. SME shifted the footprint of the coal plant outside of the NHL's designated boundaries, and the proposed natural gas facility would be located outside the boundary of the NHL.

To reduce visual impacts further, SME agreed with RUS to:

> Use earth tone colors on buildings and transmission towers, when feasible, in designing the coal-fired facility;
>
> To maximize use of downward directional lighting where appropriate and safety measures allow, in order to reduce visual impacts at night;
>
> to construct HGS infrastructure using materials and techniques to lessen visual impacts on the NHL, such as use of self-weathering (Corten) steel transmission poles, burying pipelines and re-vegetating the disturbed area, and constructing new access roads in a manner similar to existing roads; and
>
> To evaluate whether it is feasible to utilize landscaping around the facility.

These mitigating actions would be implemented for the Project. SME developed a landscaping plan for the coal-fired plant, which was approved by Cascade County, and SME would follow the landscape plan for the natural gas plant.

As recommended by RUS and the Department in the HGS EIS, SME also implemented an Archeological Monitoring Plan in conjunction with starting construction of HGS; this monitoring would be continued for further construction activities associated with the natural gas-fired generation facility.

Impacts Summary

The proposed natural gas-fired facility would be located off the NHL, wind turbines would not be constructed, and the gas plant would fit within the footprint of the previously proposed coal-fired facility, with a much smaller profile than the coal-fired plant, including stacks that would be much lower than the stack for the coal plant. The impacts of the gas plant on the NHL, in general, and on the Staging Area Interpretive Site, would be much less than the impacts of the coal plant evaluated in the EIS. Based on the level of these lower impacts and the existing development on the NHL and the surrounding area, construction and operation of the gas plant would not have a significant adverse impact on the NHL, and impacts would be moderate, at most. The no-action alternative would not affect this resource. However, continuing residential, commercial, agricultural, or industrial development in the vicinity of Great Falls is likely to impact the NHL regardless of the proposed action.

K. Cumulative and Secondary Impacts

Air quality emissions from the Project would add to background air pollutant concentrations. Acoustic and visual impacts of the Project would add to the acoustic and visual impacts of the existing development in the vicinity of the Project and would add to the existing impacts on the historical resource of the NHL.

8. *The following table summarizes the potential economic and social effects of the proposed project on the human environment.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue			X			Yes
D	Agricultural or Industrial Production			X			Yes
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities			X			Yes
G	Quantity and Distribution of Employment				X		Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity			X			Yes
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			Yes

A. Social Structures and Mores
B. Cultural Uniqueness and Diversity

The proposed project would not have any effect on social structures and mores of the proposed area of operation. The project area is located in a sparsely populated rural region, in an area whose predominant agricultural use would not change as a result of the proposed project.

Further, the facility would be required to operate according to the conditions that would be placed in Permit #4429-00, which would limit the effects to social structures and mores because air emissions would be limited by compliance with the established permit conditions.

C. Local and State Tax Base and Tax Revenue

Because of the influx of capital and employment, the existing socioeconomic environment would be affected to some degree. The increase in employment and expenditures from the construction and operation of the facility would be a direct impact to the community. Besides local expenditures by employees in the area, income may be generated in the community by the purchase of local construction material.

The operation of the Project would employ approximately 20 permanent employees with average salaries of $60,000 a year. The total annual payroll would be approximately $1.2 million. The positions would include plant operations, maintenance personnel, and engineering staff. The Project's addition of 20 well-paying, technical and professional jobs to the Great Falls region would create a minor, sustained, and beneficial economic impact on the region for the lifetime of the facility.

Another potential long-term benefit of the Project would be an increase in annual taxes to Cascade County and to the State of Montana. Annual county taxes from the Project are estimated to be $3.1 million. This estimated annual tax figure of $3.1 million was based on the tax rate for electric cooperative facilities located in Cascade County. The estimated tax was developed for the natural gas fired facility only using the tax rate in mils as published by Cascade County for general taxing/fund purposes, the tax rate associated with State Schools, the tax rate associated with District Schools, and Additional County mils for roads, library, Planning Board, Community Decay and Health Department. The estimated tax will vary as a function of the difference between the estimated and actual cost of the project.

D. Agricultural or Industrial Production

In Cascade County, just over 80 percent of all land, or 1,388,530 acres, is farmland. Of this land, 507,107 acres is cropland, with 41,901 acres irrigated. The remaining farmland (881,423 acres) is rangeland and pasture. Nearly all the undeveloped land surrounding the proposed Project site is used for cultivation, with the primary agricultural crop being winter wheat, followed by spring wheat and barley (USDA, 2003).

The proposed Project site is located entirely on Pendroy Clay soils. Pendroy Clays typically are used for dryland crops as well as rangeland, and are not listed as prime or any other important farmlands in the Cascade County soil survey (NRCS, 2004). The land evaluation productivity index for Pendroy Clays for the state Land Evaluation and Site Assessment (LESA) system is 46 of 100 (NRCS, 2002). A rating under 50 generally means that the soil is of marginal quality for agricultural uses, and that approximately 73 percent of soils ranked have a higher quality (NRCS, 2002).

Pendroy Clay soils are in land capability class 4e, which consists of soils that have very severe limitations that restrict the choice of plants or require careful management, or both. The limitations of the Pendroy Clays primarily are due to their susceptibility to erosion (RUS and MDEQ, 2007a).

The Project site previously consisted of unincorporated county land zoned A-2. A-2 is a broad classification that allows a variety of uses in addition to agriculture, such as schools, hospitals, electrical substations, etc. (Zadick, 2009). Cascade County rezoned the property to heavy industrial on March 11, 2008, at the request of the former property owners to facilitate its use for

electrical generating facilities (Zadick, 2009). The site is located east of the intersection between Salem Road and an abandoned railroad bed. The historical use of the area generally has been limited to agricultural activities.

Environmental Consequences

The area of land that would be directly affected and/or altered by the construction of the Project at the Project site includes the footprint of the power plant, roadways, and utility corridor zones required to make the plant operation-ready. Specifically, the Project would require the construction of the following elements:

- The power plant and associated facilities on a total footprint of approximately six acres;
- An 1,800-foot-long paved access road from the existing Cascade County road (Salem Road) into the site;
- The interconnection with existing transmission facilities owned by Northwestern Energy. The initial interconnection would be with an existing 230 kV line that runs from the Great Falls Substation to the Broadview Substation, near the junction of Salem Road and Highway 228 and would not cross the NHL.
- A new natural gas line would be installed to connect the Project to existing gas transmission pipelines north of the Missouri River. Northwestern Energy would construct and operate the line, which would serve SME as well as other Northwestern customers. SME's understanding is that the line would begin approximately 5 miles northeast of Great Falls, then proceed generally east to the HGS site, extending approximately 9.3 miles. The pipeline would cross under the Missouri River approximately 5 ½ miles west of the HGS facility, extend west across the property to the east of the river, and then cross the NHL in a northeasterly direction toward the HGS facility. Installation of the pipeline may have minor, short-term impacts to agricultural production if it interferes with farming activity.
- Potable water needs for the plant would be satisfied by 55,000 feet (10 miles) of fresh potable water supply from the City of Great Falls water lines or by transporting potable water to the facility from offsite.
- The power plant would generate a maximum of 216 gpm of wastewater that must be treated and would consist of concentrated river water and trace amounts of cooling tower water and boiler water treatment chemicals (RUS and MDEQ, 2007a). The wastewater would be discharged back to the City of Great Falls through 55,000 feet (10 miles) of wastewater pipeline for disposal at its existing wastewater treatment facility or would be treated and evaporated on-site, resulting in zero wastewater discharge from the Project site.

The conversion of agricultural lands to an industrial plant with supporting facilities and infrastructure would be considered only a minor impact, though the impact would be permanent. Because the agricultural land that would be converted is not prime farmland or farmland of statewide importance and does not have a significant productivity rating, the conversion of this land in context to the amount and quality of farmland in other areas of Cascade County is not considered significant.

Construction of the facility is expected to last approximately 30 months. Construction activities could cause some impacts to adjacent landowners, such as noise, dust, and increased traffic. While these impacts could nearby residents, the impacts would not affect the actual uses of adjacent land.

The operation of the power plant would cause no additional direct impacts to land use or farmland. No additional amounts of land would be developed for the plant once the construction phase is completed.

Mitigation and Monitoring

Mitigation measures taken to minimize construction and operation impacts to resource areas (e.g., reduction in noise, visibility, and air quality impacts) would directly lessen the impacts to area residents. As discussed above, SME would be required to use best management practices to minimize the ground areas disturbed by the Project's infrastructure.

Impacts Summary

The Project would involve the direct conversion of agricultural lands to an industrialized facility with supporting infrastructure. In the context of the amount of quality farmland in other areas of Cascade County, the impacts of the actual conversion, or development, of the land required for the plant would be minor. The overall impacts on land use from construction and operation of the Project would be minor. The No Action Alternative would not adversely affect or alter existing land uses at or near the Project site.

E. Human Health

On July 1, 2004, a Phase I Environmental Site Assessment (ESA) was completed on the Project site to identify recognized environmental conditions (SME, 2004c). A recognized environmental condition (REC) is defined as the presence or likely presence of any hazardous substances or petroleum products on a property, under conditions that indicate an existing release, a past release, or a material threat of a release of any hazardous substances or petroleum products into structures on the property or into the ground, groundwater, or surface water of the property. The Phase I ESA was completed in general accordance with procedures outlined in American Society for Testing and Materials (ASTM) E1527-00, Standard Practice of Environmental Assessments: Phase I ESA Process. The ESA included evaluation of individual properties adjacent to and within one mile of the Project site. There were no recognized environmental conditions or concerns identified during the site assessment at the Project site.

Environmental Consequences

Construction workers would be exposed to short-term health and safety risks typically faced in the construction industry, considered high-risk by the National Institute for Occupational Safety and Health (NIOSH). Additionally, traffic volumes and the presence of heavy construction equipment on site access roads potentially cause a negligible to minor increase in vehicular accidents. Overall, impacts on human health and safety from the construction phase of the power plant would be minor.

Operation-related impacts on human health and safety for the Project site would be minor. Occupational hazards attendant to working in an industrial electrical generation setting would be mitigated as described below. The Project has demonstrated that it can meet the requirements of law for the issuance of an air quality permit. Dispersion modeling analyses conducted for this EA and for the air quality permit indicated that concentrations of pollutants resulting from the Project would be below standards set by EPA and the Montana Board of Environmental Review to protect public health and safety.

F. Access to and Quality of Recreational and Wilderness Activities

The nearest designated wilderness area is Gates of the Mountains, about 55 miles away. The nearest state park is Giant Springs, about 8 miles from the Project site. Also near the Project site is the Lewis and Clark Historic Trail Interpretive Center, 9 miles west of the Project site (FWP, no date).

The nearest public access site is the Lewis and Clark Expedition Staging Area Interpretive Site approximately 2 miles away from the HGS gas plant site. This site provides educational and historical opportunities. Public fishing opportunities in the nearby Morony Reservoir itself are reported to be nonexistent because public access onto PPL-Montana property is prohibited (Urquhart, 2005).

Other recreational opportunities near Morony Reservoir and Morony Dam include hunting, fishing, paddling, boating and recreational trails. An extensive public trails network is located along the Missouri River in the vicinity of Great Falls. On the north side of the river, the River's Edge Trail and Sulphur Spring Trail provide users views of the NHL. The Missouri River is a free flowing river for 200 miles downstream of the Morony Dam, making for popular pubic river access.

Environmental Consequences

Construction and operation of the HGS gas plant at the Project site would entail, at most, minor impacts on recreation in the immediate project vicinity and wider Great Falls area. Development of the site would not affect access to, or the quality of, wilderness areas or other recreational opportunities. There is one cultural/educational site in the immediate vicinity that could be impacted by the Project: the Lewis and Clark Staging Area Interpretive Site. While the Project would not restrict access to it, during construction such access might be made more difficult because of heavy construction traffic. As discussed in Section 7.F of this EA, the HGS gas plant would not be visible from the Staging Area, although it is possible that steam from the plant could be visible and that plant lighting could have some effect on the darkness of the night sky in the area of the plant, as seen from the Staging Area. Also, based on a preliminary analysis of the proposed route, the transmission line would not be visible from the staging area, although existing power lines are visible from the Interpretive Site. Neither the Staging Area Interpretive Site, nor access to it, would be significantly affected by the Project.

Potential impacts of the Project to the quality of distant recreation opportunities in national park and wilderness areas, as a result of its impacts on air quality and visibility, are discussed under air quality.

Impacts Summary

Construction and operation of the Project would entail negligible to, at most, minor impacts on recreation in the immediate project vicinity and wider Great Falls area. Wilderness activities would not be affected. The No Action Alternative would not result in any direct impacts on recreation facilities or opportunities at the Project site.

G. Quantity and Distribution of Employment

Because the economic impacts of the Proposed Action at the Project site extend beyond the political boundaries of Great Falls, evaluating impacts to the Great Falls Labor Market Area (LMA) provides a comprehensive look at the affected economic environment of the region. A labor market area is an economically integrated geographic area within which individuals can reside and find employment within a reasonable distance or can readily change employment without changing their place of residence (BLS, 2005). Normally, it is based on a 60-mile radius from some pre-set point, such as the county seat, 60 miles being about a one-hour drive. The Great Falls Development Authority estimates that approximately 14,900 workers are available to employers (GFDA, no date).

The construction phase of the Project could take up to 30 months. The Project's construction would employ up to 320 workers during the peak of activity. Wage rates for construction workers would vary from approximately $20/hr to close to $40/hr. Most of the construction and engineering jobs would be highly-skilled, specialized, well-paying positions. Due to the specialized expertise required, the construction workforce is expected to be drawn primarily from outside Cascade County. Most of the workers would live in the area temporarily and would not bring their families. A relatively small fraction of the workers associated with the construction of the plant would stay for the duration of the project and potentially could relocate their families, becoming permanent residents of the Great Falls area. In an area with a population of over 55,000, this increase would be expected to have a modest economic impact and little impact on public services such as public schools.

The construction activities also could create a number of jobs indirectly from project-related spending and the spending decisions of workers. This effect, known as the employment multiplier effect, takes the impacts from project-related spending into account to determine the number of indirect or induced jobs created in the local economy by an action. Using a PC-based regional economic analysis system named IMPLAN®, the Montana Governor's Office of Economic Opportunity developed an employment multiplier of 1.5 (GOEO, 2005). Using this employment multiplier, the 320 jobs created during construction of the plant potentially could result in the creation of as many as 160 additional jobs in the community, for a total of 480 temporary jobs created by construction of the Project. Thus, the construction phase of the HGS at the Project site would have a primarily positive and beneficial effect on the socioeconomic environment of the local and regional area.

The operation of the Project would employ approximately 20 permanent employees with average salaries of $60,000 a year. The total annual payroll would be approximately $1.2 million. The positions would include plant operations, maintenance personnel, and engineering staff. The Project's addition of 20 well-paying, technical and professional jobs to the Great Falls region would create a minor, sustained, and beneficial economic impact on the region for the lifetime of the facility.

Impacts Summary

Overall, construction of the Project would have a beneficial effect on the socioeconomic environment of the local and regional area, including increases in employment opportunities, total purchases of goods and services, and an increase in the tax base. During the lifespan of the facility, the Project would result in beneficial socioeconomic impacts on aggregate income and employment in the City of Great Falls and Cascade County.

Under the No Action Alternative, the Project would not be constructed at the proposed site. The direct and indirect economic benefits to the local economy from short-term (construction) and long-term (operation) job creation would be forgone under this alternative. These are not adverse impacts, but rather a lost opportunity to realize economic benefits to the local community from the Project.

Under this alternative, SME's member cooperatives and consumers would be unprotected from possible future increases in the price of electricity on the open market. Given the volatility of this market, consumers could be paying substantially higher electric rates, although it is not possible to quantify precisely how much higher.

H. Distribution of Population

The entire project would not affect the normal population distribution in the area, because excluding the 20 jobs that would result from the facility's operation, the remainder of the jobs created from this project would be temporary. Neither the 20 positions created as a result of

operation of the facility, nor the numerous temporary construction-related positions, likely would affect the distribution of population in the area. Therefore, the Department believes that the distribution of population would not be affected.

I. Demands for Government Services

Increases would be seen in traffic on existing roadways in the area while the facility is constructed, and a lesser increase in traffic would be seen from operation of the facility. In addition, government services would be required for acquiring the appropriate permits for the proposed project and to verify compliance with the permits that would be issued. Because SME would be required to pay taxes and would require few government services, the effects on government services from this facility would be minor. Overall, any demands for government services would be minor. Details on transportation impacts follow.

TRANSPORTATION

Roads and Traffic

The HGS site is located beside the Salem Road, north of S-228 (Highwood Road), in the northeastern part of Cascade County. The portion of the county-maintained Salem Road (designated L07-204 by MDT) in Cascade County is 6.5 miles (10.5 km) long. On the east side of Belt Creek, it crosses into Chouteau County. It is an unpaved, graded, gravel road (MDT, 2001b). Salem Road is a lightly traveled, local, rural road used primarily by farmers and rural residents in the area. Based on a traffic study conducted in 2005, the average daily traffic (ADT) near Highwood Road is 36, while the ADT in the northern segment toward the HGS site is 21 (Peterson, 2005).

S-228 (Highwood Road) is a paved, two-lane, state secondary road on the Montana Secondary Highway System several miles south of the Project site that would be used to access it from Great Falls during both the construction and operation of the facility. S-228 continues east past the Salem Road intersection and intersects with S-331, a two-lane highway extending north–south. The nearest ADT measurement taken by the Montana Department of Transportation (MDT) is approximately seven miles (11 km) from its intersection with the Salem Road. The combined (both directions) ADT in 2004 was 585 (Stanley, 2009e).

US-87/89 is a four-lane highway extending southeast to northwest and intersecting S-228 southeast of Great Falls. S-227 continues south from the S-228 and US-89 intersection. US 87/89 meets 57th Street South at an angle and forms a T-intersection before continuing west. US 87/89 also is known as 10th Avenue South/S-200 within the city limits.

Environmental Consequences

Stanley Consultants developed an updated Traffic Impacts Study in 2009 based on the revised inputs of the Project (Stanley, 2009e). The construction phase of the Project is expected to last approximately 30 months and employ up to 320 construction workers during the peak six months of the construction period (Stanley, 2009e). For comparison, the estimated coal-fired power plant construction workforce was estimated at 550 employees during the peak nine months of the 43-month construction period (Stanley, 2008). In the Record of Decision for the coal plant EIS, RUS and the Department determined that the traffic impacts would be moderate and short-term during construction (RUS and DEQ, 2007b). Using this as a baseline, the traffic impacts of the Project are expected to be less due to the smaller construction workforce and shorter construction period.

From Great Falls, plant access would be from southbound U.S. Route 87/89 to eastbound S-228 to northbound Salem Road, then to the site. During the peak of the construction phase, it is anticipated that the Project would generate 648 vehicle trips per day, including material delivery trips (Stanley, 2009e). Most of the traffic related to the Project would consist of passenger cars, however, the material delivery traffic would consist of heavy vehicles. Most of the traffic would occur early in the morning and mid-to-late afternoon when workers are arriving and departing the construction site. At other times, most of the morning, mid-day, evening, and nighttime, traffic related to the Project would be minimal.

Stanley's 2009 Traffic Impact Study determined that increased traffic during the construction phase would result in the greatest potential impacts at two intersections: 1) the intersection of US 87/89 and S-228 (eastbound US 87/89 traffic turning left onto S-228 in the morning and westbound traffic turning right onto US 87/89 from S-228 in the afternoon); and 2) the intersection of 10th Ave South and 57th Street (Stanley, 2009e). Similar traffic volume increases (580 ADT) would be expected at both of these intersections. Mitigation measures for these impacts are discussed in the following Mitigation and Monitoring section.
The Project is expected to employ approximately 20 commuting workers during normal operation (Stanley, 2009e). A maximum of 10 one-way material delivery trips per week are anticipated. During the long-term operation of the HGS, traffic impacts from 20 commuting workers and 10 delivery trips per week are expected to be minimal (Stanley, 2009e).

Mitigation

Stanley Consultants developed an updated Traffic Impacts Study in March of 2009 and submitted the study to MDT for review. In the updated traffic study, Stanley proposed monitoring the traffic impacts during the construction phase to determine whether mitigating actions would be necessary.

As mentioned in the prior Environmental Consequences section, the greatest traffic impacts are likely to occur at two intersections during the construction phase: 1) the intersection of US 87/89 and S-228 and, 2) the intersection of 10th Ave South and 57th Street. Stanley evaluated three possible mitigation measures to address these impacts: 1) temporary or permanent traffic signals at one or more intersections, 2) using shuttle buses to deliver the construction workers, and 3) using a staggered start time for half of the Project workers to reduce traffic loads by 50 percent during the AM and PM peak hours.

The 2009 traffic study determined that using shuttle buses to deliver workers would have a minor beneficial impact on traffic congestion (Stanley, 2009e). The use of traffic signals at both intersections and implementing a staggered start time for half of the construction workers during the peak of the construction phase was found to measurably reduce traffic impacts at these intersections. These recommendations have been submitted to MDT and would be implemented as needed and as directed. SME has stated that it also would:

> Cooperate with MDT to implement mitigation measures identified in the 2009 Traffic Impacts Study that MDT determines to be effective and necessary;
>
> Take standard measures to minimize traffic congestion on public roads during large construction projects, including using appropriate signage to alert motorists approaching turnoffs to the construction site from both directions at distances of approximately 200 to 400 yards;
>
> If temporary detours and/or street closures are necessary at any location, ensure that road crews and signs safely and efficiently redirect oncoming traffic to the detour;

Promptly remove any material, such as aggregate or fill, falling from trucks, so as not to present a traffic hazard;

Promptly repair any damage to road surfaces from increased traffic or heavy equipment;

Maintain existing aggregate roadways to be used for construction access;

Prior to significant construction activity at the main plant site, construct roadway improvements to mitigate potential traffic problems;

Maintain Salem Road throughout construction; and

At the end of the construction phase, refurbish and pave Salem Road.

Impacts Summary

SME has identified mitigating measures and would work with MDT to implement them during construction, as needed. SME also states that it would maintain Salem Road during construction and pave it upon completion of construction.

The small workforce at the plant is expected to have minor adverse effects on traffic and roadways in the Project's vicinity during the facility's operation. Operation of the facility is expected to have negligible effects on roads in the larger Great Falls area. The No Action Alternative would not contribute directly to transportation impacts at the Project site.

J. Industrial and Commercial Activity

The facility would represent a minor increase in industrial and commercial activity in the Great Falls area. Construction activities associated with the facility would result in temporary increases in commercial activity. Currently, there is no industrial or commercial activity, other than farms, in the vicinity of the Project.

K. Locally Adopted Environmental Plans and Goals

In March 2008, the Cascade County Commissioners re-zoned the property where the Project would be located to Heavy Industrial (zoning classification I-2). The Montana Environmental Information Center and owners of some other properties in the area challenged this decision in district court. The district court upheld the County's decision. The district court's decision currently is on appeal before the Montana Supreme Court. Unless a court rules to the contrary, the current zoning permits construction and operation of the HGS facility at the Salem site.

L. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from this project on the social and economic aspects of the human environment would be minor because some new full-time employment opportunities might result, temporary construction related employment opportunities would be available, state and local taxes would be generated, and the facility could sell power to residents and industries in Montana. Overall, the HGS gas plant project would result in additional jobs for the area. As described in this EA, the facility would employ approximately 20 full-time people and approximately 320 people during the peak construction phase. The possible "day-to-day" normal operation positions and the construction-related positions created by SME would bring additional revenue into the economy.

Recommendation: No impacts from the HGS gas plant would be greater than the impacts from the previously proposed HGS coal plant, had it been built, and, in most respects, impacts from the gas plant would be less than those of the coal plant. All impacts of the natural gas plant Project would be minor except for acoustic and visual impacts, which could be moderate, at most. The natural gas plant Project would not have any significant environmental impacts. An environmental impact statement or a supplemental environmental impact statement is not required.
Other groups or agencies contacted or that may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office; Natural Resource Information System – Montana Natural Heritage Program; USDA Rural Utilities Service.

Individuals or groups contributing to this EA: Bison Engineering, Inc., on behalf of SME.; Montana Department of Environmental Quality–Air Resources Management Bureau; Montana Historical Society–State Historic Preservation Office; Montana Natural Heritage Program–Natural Resource Information System; USDA Rural Utilities Service.

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