Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

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November 26, 2008

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

Dear Mr. Gregori:

Air Quality Permit #3423-01 is deemed final as of November 26, 2008, by the Department of Environmental Quality (Department). This permit is for Southern Montana Electric Generation and Transmission Cooperative – 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,

Chuck Homer, Program Manager
Air Quality Permitting and Compliance Program
Air Resources Management Bureau
(406) 444-5279

CH
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Air Quality Permit #3423-01

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
3521 Gabel Road, Suite 5
Billings, MT 59102

November 26, 2008

MONTANA AIR QUALITY PERMIT

Issued To:	Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station 3521 Gabel Road, Suite 5 Billings, MT 59102	Permit: #3423-01 Application Complete: 9/29/08 Preliminary Determination Issued: 10/6/08 Department's Decision Issued: 11/10/08 Permit Final: 11/26/08 AFS #013-0038

An air quality permit, with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS), 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. Plant Location

The SME-HGS plant encompasses approximately 720 acres of property and is located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,268 km. The site elevation is approximately 3,290 feet above sea level.

B. Current Permit Action

On June 6, 2008, the Department of Environmental Quality (Department) received an "Addendum to Application for Air Quality and Operating Permits" from SME for Permit #3423-00. The addendum application included a proposed Best Available Control Technology (BACT) determination for particulate matter with an aerodynamic diameter equal to or less than 2.5 micrometers ($PM_{2.5}$). On September 29, 2008, the Department received a revised addendum application, and the Department determined the submitted application materials were complete.

The current permit action is a modification to Montana Air Quality Permit (MAQP) #3423-00 pursuant to the Order issued by the Board of Environmental Review (BER) in the matter of contested case number BER 2007-07 AQ. The modification establishes permit limitations, conditions and reporting requirements in accordance with the results of the $PM_{2.5}$ specific top-down BACT determination submitted by SME for the Circulating Fluidized Bed (CFB) Boiler. Additionally, SME requested 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 are included for hydrochloric acid (HCl), hydrofluoric acid (HF), as well as, boiler heat input rate and control technology requirements, as revisions to Section II.A.10; II.B.5 and 6; Section II.C.11, 12, 15, 19 and 20; and Section II.N.1g and h of the permit. Also included are corresponding reporting requirements in Section II.O and notification requirements in Section II.Q.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. SME-HGS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and ARM 17.8.752).

2. SME-HGS shall not cause or authorize emissions to be discharged into the atmosphere from haul roads, access roads, parking lots, or the general plant property without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308 and ARM 17.8.752).

3. SME-HGS 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.2 (ARM 17.8.752).

4. SME-HGS shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of airborne particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308 and ARM 17.8.752).

5. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60, Subpart Da).

6. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart Db).

7. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60, Subpart Y).

8. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart OOO (ARM 17.8.340 and 40 CFR 60, Subpart OOO).

9. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE) MACT (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).

10. SME-HGS shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), mercury content, fluoride content, and chlorine content (ARM 17.8.749).

11. SME-HGS shall obtain a written fuel oil analysis for each shipment of fuel oil received from each fuel oil supplier. The analysis shall contain, at a minimum, the sulfur content of the fuel oil and the vapor pressure of the fuel oil (ARM 17.8.749).

B. CFB Boiler Start-Up and Shutdown Operations

1. CFB start-up and shutdown operations shall be conducted as described in the *CFB Boiler Start-Up and Shutdown Procedures* included in Attachment 3 of Permit #3423-01 or according to another start-up and shutdown plan as may be approved by the Department in writing (ARM 17.8.749 and ARM 17.8.752).

2. CFB Boiler start-up operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the CFB Boiler (ARM 17.8.749).

3. During start-up and shutdown operations, the CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).

4. During start-up and shutdown operations, oxides of nitrogen (NO_x) emissions from the CFB Boiler stack shall not exceed 388 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. During start-up, SME shall begin operating the IC-FFB just prior to first firing of the boiler on start-up fuels and operation of other pollution control devices as applicable with increasing boiler temperature as described in Attachment 3 (ARM 17.8.752).

6. During shutdown, SME shall continue to operate the IC-FFB until the ID fan is deactivated and all other pollution control equipment shall remain online until minimum operation temperatures are reached as described in Attachment 3 (ARM 17.8.752).

C. CFB Boiler

1. The CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight except during periods of start-up or shutdown (ARM 17.8.749 and ARM 17.8.752).

2. SME-HGS shall operate an Integrated Emission Control System (IECS) including CFB limestone injection technology, enhanced hydrated ash re-injection (HAR) with lime injection technology, a selective non-catalytic reduction (SNCR) unit, and a fabric filter baghouse (FFB) using intrinsically Teflon™ coated woven fiber bags for CFB Boiler emissions control except as specified in Attachment 3 during start-up and shutdown operations (ARM 17.8.752).

3. SME-HGS shall not cause or authorize to be discharged into the atmosphere from the CFB Boiler stack any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Da).

4. Filterable particulate matter (filterable PM) emissions from the CFB Boiler stack shall be limited to 0.012 lb/MMBtu and 33.25 lb/hr (ARM 17.8.752).

5. Particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) emissions (filterable and condensable) from the CFB Boiler stack shall be limited to 0.026 lb/MMBtu and 72.04 lb/hr (ARM 17.8.752).

6. The CFB Boiler's PM_{10} emission limit shall be used as a surrogate emission limit for radionuclides and trace metals (ARM 17.8.752).

7. Except during periods of start-up and shutdown, NO_x emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.10 lb/MMBtu based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.09 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.07 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

8. CO emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. CO emissions from the CFB Boiler stack shall not exceed 0.10 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

9. Sulfur dioxide (SO_2) emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.057 lb/MMBtu based on a 3-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.048 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.038 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

10. Volatile Organic Compounds (VOC) emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. VOC emissions from the Boiler stack shall not exceed 0.003 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

11. Hydrochloric Acid (HCl) Emissions

    a. HCl emissions from the CFB Boiler stack shall not exceed 0.00085 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.749).

    b. If, after initial source testing, SME demonstrates in writing that it is not technically feasible to operate the IECS equipment such that the above HCl limit can be met at a continuous equivalent heat input rate of 21,764,737 MMBtu rolling 12 month total, the HCl emission limit shall change to (in conjunction with heat input rate limits at Section II.C.15): HCl emissions from the CFB Boiler stack shall not exceed 0.00090 lb/MMBtu averaged over any 1-hour time period. This change will be effective upon written approval of the request and associated source test report by the Department (ARM 17.8.749).

12. Hydrofluoric Acid (HF) Emissions

    a. HF emissions from the CFB Boiler stack shall not exceed 0.00075 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.749).

    b. If, after initial source testing, SME demonstrates in writing that it is not technically feasible to operate the IECS equipment such that the above HF limit can be met at a continuous equivalent heat input rate of 21,764,737 MMBtu rolling 12 month total, the HF emission limit shall change to (in conjunction with heat input rate limits at Section II.C.15): HF emissions from the CFB Boiler stack shall not exceed 0.00080 lb/MMBtu averaged over any 1-hour time period. This change will become effective upon written approval of the request and associated source test report by the Department (ARM17.8.749).

13. Sulfuric Acid (H_2SO_4) mist emissions from the CFB Boiler stack shall not exceed 0.0054 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

14. Mercury Emissions

    a. Following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), mercury emissions from the CFB Boiler shall not exceed 0.0000015 lb/MMBtu (1.5 pounds per trillion Btu (lb/TBtu)) based on a rolling 12-month average, or an emission rate equal to a 90% or greater reduction of mercury in the as-fired coal, as measured in lb/TBtu and based on a rolling 12-month average. Mercury emissions from the CFB Boiler shall be controlled by the IECS or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency) (ARM 17.8.752).

    b. Prior to commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall install an activated carbon injection (ACI) control system or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency). Within 6 months after commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall operate the ACI control system, or an equivalent technology (equivalent in removal efficiency) (ARM 17.8.749).

15. Heat Input

    a. Heat input to the CFB-Boiler shall not exceed 21,764,737 MMBtu during any rolling 12-month time period (ARM 17.8.749).

    b. If, after initial source testing, SME demonstrates in writing that it is not technically feasible to operate the IECS equipment such that the HF or HCl limits at Sections II.C.11a and 12a can be met at a continuous equivalent heat input rate of 21,764,737 MMBtu rolling 12 month total, the heat input limit shall change to (in conjunction with acid gas limits at Sections II.C.11a and 12a): heat input to the CFB Boiler shall not exceed 21,110,000 MMBtu during any rolling 12-month time period. This change will become effective upon written approval of the request and associated source test reports by the Department (ARM 17.8.749).

16. The CFB Boiler stack height shall be maintained at a height of at least 400 feet above ground level (ARM 17.8.749).

17. Not later than 18 months after reference test methods for $PM_{2.5}$ are promulgated final by EPA, SME shall submit to the Department an application for permit modification to establish a $PM_{2.5}$ emission limit. $PM_{2.5}$ limits shall be requested and established based on measured $PM_{2.5}$ emission rates that correspond with operational practices that are in compliance with the condition at Section II.C.20 (ARM 17.8.749).

18. SME shall submit ED-FGD and IC-FFB design specifications to the Department along with a detailed explanation of how the system will achieve $PM_{2.5}$ emissions control. SME shall submit this information within 90 days of Permit #3423-01 being issued Final (ARM 17.8.752).

19. To control emission of $PM_{2.5}$, from the CFB Boiler, SME shall install an ED-FGD followed by IC-FFB technology, as they are described in Section III of the attached Permit Analysis and the record, in accordance with manufacturer's specifications (ARM 17.8.752).

20. To control $PM_{2.5}$ emission from the CFB Boiler, SME shall operate the ED-FGD and IC-FFB, as described in Section III. BACT Determination of the Permit Analysis, at all times except as specified in Attachment 3 as applicable during start-up and shutdown operations. In addition, SME shall maintain the ED-FGD and IC-FFB in accordance with manufacturer's specifications (ARM 17.8.752).

D. Auxiliary Boiler

1. The Auxiliary Boiler shall be limited to 850 hours of operation during any rolling 12-month time period (ARM 17.8.752 and 40 CFR 60, Subpart Db).

2. The Auxiliary Boiler shall combust only fuel-oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).

3. SO_2 emissions from the Auxiliary Boiler shall be limited to 12.63 lb/hr (ARM 17.8.749).

4. NO_x emissions from the Auxiliary Boiler shall be controlled by the installation and operation of dry low-NO_x (DLN) burners. NO_x emissions from the Auxiliary Boiler shall be limited to 46.80 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices. CO emissions from the Auxiliary Boiler shall be limited to 18.60 lb/hr (ARM 17.8.749 and ARM 17.8.752).

6. VOC emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

7. PM_{10} emissions from the Auxiliary Boiler shall be limited to 3.20 lb/hr (ARM 17.8.749).

8. The Auxiliary Boiler stack height shall be maintained at a height of at least 220 feet above ground level (ARM 17.8.749).

E. Coal Fuel Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any Standards of Performance for New Stationary Source (NSPS)-affected equipment shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Y).

2. All conveyors shall be enclosed or covered and all outdoor conveyor transfer points shall be covered and vented to a FFB or bin vent, except the following transfer points shall be controlled by wet dust suppression and any other necessary reasonable precautions (ARM 17.8.752):

   - Conveyor CC01 to Emergency Coal Pile;
   - Fly-ash Pug Mill 1 to Truck Load-out;
   - Fly Ash Truck Transport to On-site Ash Disposal Area;
   - Bed Ash Pug Mill 2 to Truck Load-Out; and
   - Bed Ash Truck Transport to On-site Ash Disposal Area.

3. All railcar coal deliveries/transfers shall be unloaded within the Rail Unloading Building via belly-dump to a below grade hopper. The Railcar Unloading Building shall be vented to FFB DC1 and maintained under constant negative pressure when coal is being unloaded and conveyed within the building (ARM 17.8.752).

4. PM_{10} emissions from FFB DC1 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

5. All coal deliveries to the Railcar Unloading Building shall be transferred via below ground feeders to a conveyor (MC02) (ARM 17.8.752).

6. Transfer Tower 16 shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

7. PM_{10} emissions from FFB DC2 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

8. The emergency coal pile shall be compacted and sprayed with water and/or chemical dust suppressant, as necessary, to maintain compliance with the reasonable precautions requirement and opacity limits (ARM 17.8.752).

9. Coal Silo (CS-1) shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

10. The Coal Crusher House shall be vented to FFB DC3 and shall be maintained under constant negative pressure when processing coal (ARM 17.8.752).

11. The coal crushers (2), surge bin, and rotary feeders (2) shall be enclosed within the Coal Crusher House and vented to FFB D3 (ARM 17.8.752).

12. PM_{10} emissions from FFB D3 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

13. All coal transfers through the tripper system to the day bins located in the CFB Boiler house shall be enclosed and routed to FFB DC4 (ARM 17.8.752).

14. PM_{10} emissions from FFB DC4 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

F. Limestone and Lime Material Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any NSPS-affected crusher shall not exhibit an opacity of 15% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

2. Visible emissions from any other NSPS-affected equipment, such as screens or conveyor transfers, shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

3. All limestone material shall be delivered to the facility via bottom dumping haul-trucks and unloaded within a limestone material unloading drive-through building. The limestone material unloading drive-through building shall be maintained under constant negative pressure and vented through FFB DC5 when limestone material is being unloaded and conveyed within the drive-through building (ARM 17.8.752).

4. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to FFB DC5 (ARM 17.8.752).

5. All limestone material transfers to the Bucket Elevator and the Limestone Silo shall be vented to FFB DC5 (ARM 17.8.752).

6. PM_{10} emissions from FFB DC5 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

7. Visible emissions from FFB DC5 shall not exhibit an opacity of greater than 7% averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

G. Fly and Bottom-Ash Material Processing, Handling, Transfer, and Storage Operations

1. Fly-ash shall be pneumatically transferred from the CFB Boiler FFB to the Fly-Ash Silo (AS1) (ARM 17.8.752).

2. Bed-ash shall be pneumatically transferred from the CFB Boiler to the Bed-Ash Silo (AS2) (ARM 17.8.752).

3. PM_{10} emissions resulting from the charging of AS1 and AS2 shall be controlled by fabric filter Bin vents DC6 and DC7, respectively (ARM 17.8.752).

4. Fly-ash and bed-ash shall be gravity-fed into haul trucks through a wet pug-mill (ARM 17.8.752).

5. Air displaced by ash loading into haul trucks shall be vented through AS1 and AS2 and associated bin vents DC6 and DC7, respectively (ARM 17.8.752).

6. PM_{10} emissions from each bin vent DC6 and DC7 shall be limited to 0.01 gr/dscf (ARM 17.8.752).

7. Visible emissions from bin vent DC6 and DC7 shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.752).

H. Coal Thawing Shed Operations

1. The Coal Thawing Shed Heater shall be limited to 240 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Coal Thawing Shed Heater shall combust only propane or pipeline quality natural gas (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Coal Thawing Shed Heater operations shall be controlled by proper design and operation, good combustion practices, and the combustion of propane or pipeline quality natural gas only (ARM 17.8.752).

I. Emergency Fire Pump Operations

1. The Emergency Fire Pump shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Fire Pump shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Fire Pump shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

J. Emergency Generator Operations

1. The Emergency Generator shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Generator shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Generator shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

4. NO_x emissions from the Emergency Generator shall be limited to 41.20 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Emergency Generator shall be limited to 2.70 lb/hr (ARM 17.8.749 and ARM 17.8.752).

K. Cooling Tower

1. PM_{10} emissions from the Cooling Tower shall be controlled by drift eliminators (ARM 17.8.752).

2. The Cooling Tower drift rate shall be limited to 0.002% of the total circulating water flow, by manufacturer's design (ARM 17.8.752).

L. Fuel Storage Tank

SME-HGS shall not store any liquid fuel with a vapor pressure greater than 3.5 kilopascals (kPa) in the 275,000-gallon capacity fuel storage tank (ARM 17.9.749).

M. CFB Boiler Refractory Brick Curing Heaters

1. SME-HGS shall operate the CFB Boiler refractory brick curing heater(s) only for the purpose of curing CFB Boiler refractory brick. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation during any rolling 12-month time period (ARM 17.8.752).

2. The CFB Boiler refractory brick curing heaters shall combust propane fuel only (ARM 17.8.752).

3. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 2771 MMBtu/hr (ARM 17.8.749).

4. SME-HGS shall not operate the CFB Boiler refractory brick curing heater(s) when electricity is being generated through CFB Boiler operations or when the boiler fuel feed (diesel or coal) is operational (ARM 17.8.749).

N. Testing Requirements

1. CFB Boiler Testing Requirements

a. SME-HGS shall initially test the CFB Boiler for opacity within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the applicable opacity limit (ARM 17.8.749).

b. SME-HGS shall initially test the CFB Boiler for filterable PM emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

c. SME-HGS shall initially test the CFB Boiler for PM_{10} (filterable and condensable) emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/ monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

d. SME-HGS shall initially test the CFB Boiler for NO_x emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler. SME-HGS shall conduct the initial performance source testing for NO_x and CO, concurrently. SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the continuous emissions monitoring system (CEMS), as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the NO_x CEMS to monitor compliance with the applicable NO_x emission limits (ARM 17.8.105 and ARM 17.8.749).

e. SME-HGS shall initially test the CFB Boiler for CO emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for CO and NO_x, concurrently (ARM 17.8.105 and ARM 17.8.749).

   After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

f. SME-HGS shall initially test the CFB Boiler for SO_2 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler. 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 (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   After the initial source test, SME-HGS shall use the data from the SO_2 CEMS to monitor compliance with the applicable SO_2 emission limits (ARM 17.8.749).

g. SME-HGS shall initially test the CFB Boiler for HCl emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

   After the initial source test, additional testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

h. SME-HGS shall initially test the CFB Boiler for HF emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

   After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

i. SME-HGS shall initially test the CFB Boiler for H_2SO_4 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

   After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

j. SME-HGS shall monitor compliance with the applicable mercury emission limit(s) pursuant to 40 CFR 60.48a through 60.52a and 40 CFR 75, Subpart I. Any mercury CEMS used must be operated in compliance with 40 CFR 60, Appendix B. 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 (ARM 17.8.105, ARM 17.8.749, 40 CFR 60, Subpart Da, and 40 CFR 75, Subpart I)

2. Coal Fuel, Limestone, and Ash Processing, Handling, Transfer, and Storage Operations Testing Requirements

a. Compliance with the opacity limit for FFB DC1, controlling emissions from rail unloading material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

b. Compliance with the PM_{10} emission limit for FFB DC1 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every-5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

c. Compliance with the opacity limit for FFB DC2, controlling emissions from coal silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

d. Compliance with the PM_{10} emission limit for FFB DC2 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

e. Compliance with the opacity limit for FFB DC3, controlling emissions from coal crusher material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

f. Compliance with the PM_{10} emission limit for FFB DC3 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

g. Compliance with the opacity limit for FFB DC4, controlling emissions from tripper deck plant silos material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

h. Compliance with the PM_{10} emission limit for FFB DC4 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

i. Compliance with the opacity limit for FFB DC5, controlling emissions from limestone material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

j. Compliance with the PM_{10} emission limit for FFB DC5 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

k. Compliance with the opacity limit for bin vent DC6, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749).

l. Compliance with the opacity limit for bin vent DC7, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749)

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).

O. Operational Reporting Requirements

1. SME-HGS shall submit to the Department 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-HGS shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or that would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, at least 10 days prior to start up 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(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by SME-HGS 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).

4. SME-HGS shall document, by month, the total heat input to the CFB Boiler. By the 25th day of each month, SME-HGS shall total heat input to the CFB Boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month boiler heat input limitation (ARM 17.8.749).

5. SME-HGS shall document, by month, the hours of operation of the Auxiliary Boiler. By the 25th day of each month, SME-HGS shall total the operating hours of the Auxiliary Boiler for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

6. SME-HGS shall document, by month, the hours of operation of the Emergency Generator. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Generator for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

7. SME-HGS shall document, by month, the hours of operation of the Emergency Fire Water Pump. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Fire Water Pump for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

8. SME-HGS shall document, by month, the hours of operation of the Coal Thawing Shed Heater. By the 25th day of each month, SME-HGS shall total the operating hours of the Coal Thawing Shed Heater for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

9. SME-HGS shall maintain on site the coal fuel and fuel oil analyses required under Section II.A and submit this information to the Department upon request (ARM 17.8.749).

10. SME-HGS shall maintain a record of CFB Boiler start-up operations. SME-HGS shall document the total start-up operating hours from initial fuel feed to the CFB Boiler for each start-up period. The information shall be submitted to the Department upon request. The information will be used to monitor compliance with the CFB Boiler start-up operating hour limit (ARM 17.8.749).

11. SME-HGS shall monitor and analyze the CFB Boiler mercury control performance data following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH). By the 25th day of each month, SME-HGS shall summarize the applicable mercury emissions data (percent reduction and/or emission rate). SME-HGS shall submit this information to the Department quarterly, or according to another reporting schedule as may be approved by the Department in writing. The information will be used to verify the IECS mercury control capabilities (ARM 17.8.749).

12. SME-HGS shall document, by month, the hours of operation of the refractory brick curing heaters. By the 25th day of each month, SME-HGS shall total the operating hours of the refractory brick curing heaters for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

13. SME shall log and report annually (along with information reported in accordance with the condition at Section O.1 of the Permit) operational parameters including lime and ash injection rates in the ED-FGD, pressure drop across the IC-FFB, temperature and flow rate, bag cleaning records, equipment maintenance and replacement logs, and any other pertinent or critical operation and maintenance information as identified in the Operation and Maintenance Manual. (ARM 17.8.752)

P. Continuous Emissions Monitoring Systems (CEMS/COMS)

1. SME-HGS shall install, operate, calibrate, and maintain CEMS as follows:

   a. A CEMS for the measurement of SO_2 shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   c. A CEMS for the measurement of NO_x shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   d. A COMS for the measurement of opacity shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on the CFB-Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   f. A continuous monitoring methodology for the measurement of mercury shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).

2. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, #3, and #12A) (ARM 17.8.749 and 40 CFR 60).

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

4. SME-HGS shall inspect and audit the COMS annually, using neutral density filters. SME-HGS shall conduct these audits using the applicable procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.749).

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

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

Q. Notification

1. Within 30 days after commencement of construction of the SME-HGS facility, SME-HGS shall notify the Department of the date of commencement of construction (ARM 17.8.749).

2. Within 30 days after commencement of construction of the CFB Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749).

3. Within 15 days after actual startup of the CFB Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

4. Within 30 days after commencement of construction of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749).

5. Within 15 days after actual startup of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

6. Within 30 days after commencement of construction of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

7. Within 15 days after actual startup of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

8. Within 30 days after commencement of construction of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter bin vent(s) (ARM 17.8.749).

9. Within 15 days after actual startup of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter bin vent(s) (ARM 17.8.749).

10. Within 30 days after commencement of construction of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of commencement of construction of the affected unit(s) and provide the maximum heat input capacity of the affected unit(s) (ARM 17.8.749).

11. Within 15 days after actual startup of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of actual startup of the affected unit(s) (ARM 17.8.749).

12. Within 180 days of start-up, SME shall provide to the Department a complete Operation and Maintenance Manual for the ED-FGD and IC-FFB apparatus and ancillary equipment. The manual shall identify critical operating parameters such as temperature, pressure drop, gas flow rate, maintenance, cleaning schedules and any other operational parameters essential to proper function of the equipment (ARM 17.8.749).

13. Within 180 days of start-up, SME shall provide a one-time notification to the Department that the ED-FGD and IC-FFB were constructed to the design specifications provided in accordance with Section II.C.18 (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – SME-HGS shall allow the Department's representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) 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-HGS fails to appeal as indicated below.

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

D. Enforcement – Violations of 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 17.8.763.

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 by SME-HGS to pay the annual operation fee may be grounds for revocation of this permit, as allowed by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 18 months after permit issuance of Permit #3423-00 and proceed with due diligence until the project is complete or Permit #3423-01 shall expire. If the permit expires, SME-HGS shall not commence construction until SME-HGS has applied for and received a new air quality permit pursuant to Sections 75-2-204 and 75-2-211, Montana Code Annotated, and ARM 17.8.740 *et seq*., as amended (ARM 17.8.762).

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 start up, shut down, 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 start up, shut down, 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[a] /total hours of point source operation during reporting period)) x 100

a - 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 <u>all</u> 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.

Attachment 2

EXCESS EMISSIONS REPORT

PART 1 – General Information

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 ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

l. Percent of Time Out of Compliance: Opacity ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

m. Amount of Product Produced
During Reporting Period ______________________________

n. Amount of Fuel Used During Reporting Period ______________________________

Attachment 2

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO_2 NO_x O_2 CO_2 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 SO_2 NO_x 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 ______________________________

Attachment 2

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

Attachment 2

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

Attachment 2

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	To	Duration	Operating Parameters	Corrective Action

Attachment 2

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S 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. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	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. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

[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
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-01

CFB Boiler start-up and shutdown operations shall be conducted as described in this attachment, recognizing that these are typical operational procedures, and that variations may occur. For the purposes of this procedure and associated permit limits and conditions start-up is defined as the period beginning with the commencement of loading bed material into the furnace and ending when boiler has reached 70% of maximum load or heat input rate of 1939 MMBtu/hr. Shutdown is defined as the period beginning when the boiler is decreased to 70% of load or a heat input rate of 1939 MMBtu/hr and ending when the ID cooling fan is deactivated.

I. CFB Boiler Start-Up Operations

Startup of a circulating fluidized bed (CFB) boiler is a three-phase operation that can take up to 48 hours depending on the initial furnace temperature and conditions of the fluidized bed. During the three-phase startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, particulate mater (PM), oxides of nitrogen (NO_x), and sulfur dioxide (SO_2) emissions may vary until air pollution control equipment can be operated at a minimum continuous load.

A. Phase 1 - CFB Boiler Bed Material Preparation

Phase 1, the first step in the startup of a CFB, involves loading the initial bed material into the furnace. Either sand or used bed ash is loaded into the bed utilizing a pneumatic system. This step can take several hours to complete, during which time there is no fuel combustion taking place. The emissions present during the ash loading cycle are particulate matter. The fabric filter baghouse will not be operational during this first phase; however, entrained particulate matter is expected to remain within the boiler.

B. Phase 2 – Introduction of Startup Fuel

Introduction of startup fuel in Phase 2 is estimated to take approximately 12 hours. Once the bed material is loaded into the furnace, the fans are started and the CFB boiler begins to fire on the startup fuel. The startup fuel is utilized to warm the bed material and the CFB Boiler components. Startup fuel use is increased until the temperature inside the cyclone reaches approximately 1150°F. From a cold start, this process may take 14 hours or longer. During this warm-up period, NO_x is controlled through efficient low NO_x burners; SO_2 is minimized through the use of low sulfur fuels; and particulate matter is controlled through use of the IC-FFB. Carbon monoxide (CO) emissions may be higher than full load operation due to combustion conditions in the furnace during this period. The firing is expected to be approximately 831 million British thermal units per hour (MMBtu/hr) (30% of the maximum CFB Boiler heat input rate of 2,771 MMBtu/hr).

C. Phase 3 – Introduction of Coal

Phase 3 starts after the temperature inside the cyclone reaches 1150°F and typically lasts approximately 6 hours, but may last longer. During Phase 3, coal and limestone are introduced into the furnace and the feed rate is increased over the next 2 hours until the coal becomes the primary fuel source. During this time, both startup fuel and coal are combusted together. The startup fuel feed rate is slowly reduced and is eventually shut off. During this transition, NO_x is controlled by the use of low NO_x burners and the staged combustion of the coal. SO_2 is controlled by the use of low sulfur fuels and the addition of limestone to the fluidized bed, and particulate matter is controlled through the use of the IC-FFB.

At approximately 50% of full load the NO_x is further reduced by adding ammonia injection via the Selective Non-catalytic Reduction (SNCR) system. In addition, approximately 4 hours after the limestone is injected into the fluidized bed, the secondary flue gas desulphurization (FGD) (hydrated ash reinjection) unit is activated to further reduce SO_2 emissions. At this point in the boiler start-up process, all emissions control equipment is fully activated. Start-up operations are limited by permit to no longer than 48 hours.

II. CFB Boiler Shutdown

Several steps are required for a controlled shutdown of the boiler and the associated ancillary equipment. The first step of the process is to shut down the coal feed into the furnace. In order to accomplish this, the coal feed and firing rate is gradually reduced. As the temperature is reduced below minimum requirements for the secondary FGD (hydrated ash reinjection) and SNCR systems, these systems are turned off. The furnace is brought down to the minimum coal firing rate. At this point the coal feed is completely shut off and the furnace is purged with air. The air will be used to gradually lower the boiler temperature for inspection or maintenance. Once the boiler is cooled off, the ID Fan will be turned off. If no access into the furnace is required, the bed ash will be discharged and pneumatically conveyed to the ash silo, where it will be stored until the next startup. In the event that the boiler shutdown is only for a short period, and the re-operation of the unit is anticipated, the fans will be turned off, and the ID Fan control damper will be closed in order to bottle up the furnace and maintain the maximum amount of heat.

Permit Analysis
Southern Montana Electric Generation and Transmission Cooperative –
Highwood Generating Station
Permit #3423-01

I. Introduction/Process Description

A. Permitted Equipment

Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS) operates a net 250-megawatt (MW) electrical power generating plant located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above sea level.

The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler) with an average annual heat input value of 2,626 million British thermal units per hour (MMBtu/hr) and a maximum short-term heat input capacity of 2,771 MMBtu/hr to produce approximately 1.8 million pounds of steam per hour. The steam is routed to a steam turbine, which drives an electric generator capable of producing an estimated 270 gross MW of electrical power. Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in the approximate net power production capacity of 250 MW. The following equipment/emission sources are permitted for this facility:

- 2771 MMbtu/hr heat input capacity coal fired CFB Boiler (2626 MMBtu/hr average)
- 225 MMBtu/hr heat input capacity diesel fuel-oil, propane, or natural gas fired Auxiliary Boiler
- 2000 kilowatt (kW) emergency diesel fuel-oil fired generator set
- 230 kW emergency diesel fuel-oil fired Emergency fire pump
- 40 MMBtu/hr heat input capacity propane/natural gas fired Coal Thawing Shed Heater
- Cooling Tower
- Fabric Filter Baghouse (FFB) DC1 controlling rail unloading material transfers
- FFB DC2 controlling coal silo material transfers
- FFB DC3 controlling coal crusher operation and material transfers
- FFB DC4 controlling tripper deck plant silos material transfers
- FFB DC5 controlling limestone material transfers
- Fabric Filter bin vent DC6 controlling fly ash silo (AS-1) material transfers
- Bin vent DC7 controlling bottom ash silo (AS-2) material transfers
- Emergency Coal Storage Pile
- Ash Storage/Disposal Monofill
- 275,000 gallon capacity diesel fuel-oil storage tank
- Haul Roads/vehicle traffic
- 2771 MMBtu/hr heat input capacity portable/temporary propane fired CFB Boiler refractory brick curing heater(s)

B. Source Description

1. CFB Boiler

The CFB Boiler will combust low-sulfur coal except during periods of start-up and shutdown when pipeline quality natural gas, propane, or low-sulfur diesel fuel-oil may be combusted. Regulated pollutants emitted from the CFB-Boiler will be controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS).

The CFB Boiler technology uses a bed of crushed coal and limestone and recycled heavy ash particles suspended (fluidized) in an upwardly flowing air stream. Air enters near the bottom of the furnace and is staged through air distribution nozzles to minimize the formation of NO_x. The coal and limestone are metered and fed into the furnace bed. Combustion takes place in the fluidized bed, which is limited in temperature to reduce the formation of NO_x. The fine particles of limestone react with the sulfur in the coal and reduce the formation of SO_2. The heavier combustion byproduct particles are carried in the flue gas through the furnace, collected in a cyclone separator, and are then circulated back into the furnace.

The SNCR system is used to control NO_x emissions. Ammonia (NH_3) is injected into the cyclone separator and mixed with the flue gas. The NH_3 reacts with the flue gas to convert NO_x into nitrogen gas (N_2), and water vapor (H_2O). The HAR system is used to control SO_2 emissions. The HAR is a dry flue gas desulfurization (FGD) process; the system mixes water with fly ash and available lime (produced during heating of the limestone in the CFB Boiler) to react with the SO_2 in the flue gas to form particulate, which is collected downstream in FFB. The FFB is used for particulate emissions control. The fabric filter consists of multiple fabric bags that capture lighter particles in the exhaust gases downstream of the cyclone separator. These lighter particles include fly ash and lighter solids created in the chemical reaction processes. Carbon monoxide (CO) and Volatile Organic Compounds (VOC) emissions will be controlled by best management practices (BMP) and staged combustion of air ensuring proper operation of the CFB Boiler. Limestone injection in the CFB Boiler and the HAR system, collectively, will also remove acid gases including sulfuric acid (H_2SO_4), hydrochloric acid (HCl) and hydrofluoric acid (HF). In addition, the FFB will reduce emissions of metals including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, mercury, and manganese. A co-benefit of mercury emission reduction will result from the overall IECS design. Absorption of mercury will be realized in the CFB Boiler due to the source of unburned carbon, use of limestone injection, SNCR, and the HAR system. The mercury in particulate form will then be collected in the FFB. In addition, mercury specific activated carbon injection (ACI) emission controls (or equivalent) must be installed prior to commencement of commercial operations and operated after a 6-month IECS operational period. After passing through the FFB, the flue gas will exit to atmosphere through the 400-feet tall CFB Boiler stack. The height of the stack was selected to minimize the visual impact of the plant while maintaining adequate dispersion.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Pump, and Coal Thawing Shed

The auxiliary boiler will combust #2 diesel fuel, natural gas, or propane and will be in operation only during periods of CFB Boiler startup, shutdown, and commissioning, and during extended downtimes of the CFB Boiler during winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will combust only low-sulfur diesel fuel-oil and operate only during emergencies and during required maintenance. The Coal Thawing Shed Heater will only operate on propane or natural gas and during times when the coal is frozen in the coal train cars.

3. Cooling Tower

A wet cooling tower 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 tower. The cooling tower will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling tower will be approximately 2,250 gallons per minute (gpm). Water will be delivered to the facility via pipeline from the Missouri River.

4. Coal Fuel Processing, Handling, Transfer, and Storage Operations

Facility operations will utilize several proposed conveyors, transfer points, and storage facilities to handle the coal fuel material required for the operation of the CFB Boiler. The coal storage and handling system begins with coal delivered by railcars to the SME-HGS facility. Coal deliveries are estimated to be two trains per week or approximately 22,000 tons of coal per week.

The coal delivery railcars will pass through the Coal Thawing Shed, which will thaw frozen wintertime coal shipments before the railcars enter the Rail Unloading Building. Inside the Rail Unloading Building the coal railcars will be unloaded via a belly dump into a below-grade hopper. From the hopper, the coal will be transferred onto a covered belt conveyor (MC02). The Rail Unloading Building will be vented to an induced draft FFB DC1, which will maintain a constant negative pressure within the building. FFB DC1 will provide emission control for coal transfers from the below-grade feeders to conveyor MC02. MC02 will deliver the coal to the enclosed Transfer Tower 16. The Transfer Tower will be vented to the induced draft FFB DC2 located near the coal silo. The Transfer Tower will direct the coal to either the coal silo or to the outdoor long-term coal storage pile (emergency coal pile). The emergency coal pile will store enough coal to supply the CFB Boiler for approximately one month and be used during interruptions in coal deliveries. The emergency coal pile will be compacted and sprayed with water or surfactant to minimize coal dust emissions. Coal transferred to the emergency coal storage pile will be diverted to the Coal Stackout Conveyor (CC01) and will then enter the Lowering Well where emissions will be controlled by the Lowering Well design. Coal will be reclaimed from the coal storage pile by below-grade vibrating reclaim hoppers and a belt feeder. The reclaimed coal will be moved onto the Coal Reclaim Conveyor (CC03) and returned to Transfer Tower 16. Coal not directed to the emergency coal pile or reclaimed from the emergency coal pile will be transferred to the Coal Transfer Conveyor (CC02) inside Transfer Tower 16. CC02 feeds the Coal Silo (CS-1), which is sized to hold coal for several days of CFB Boiler operations. The coal transfers associated with CC04 are controlled by FFB DC2 located at the coal silo. FFB DC2 will also control coal dust emissions from the transfer of coal from the feeder located at the bottom of CS-1 to the Coal Feeder Conveyor (CC04). CC04 transfers coal to the Coal Crusher House which encloses a coal surge bin, two rotary feeders, and two coal crushers and is controlled by FFB DC3, which also controls emissions from the Coal Transfer Conveyor CC05. Crushed coal on CC06 is transferred to the Tripper System (comprised of the Tripper Conveyor and Traveling Tripper) and is controlled by FFB DC4.

5. Limestone Processing, Handling, Transfer, and Storage Operations

Covered, over-the-highway, bottom-dumping trucks will deliver limestone material to the SME-HGS facility and will be unloaded in a drive-through building, which is controlled by FFB DC5. The Limestone Transfer Conveyor (LC01) will move the delivered limestone to the Limestone Bucket Elevator (LC02), and discharge into the Limestone Silo (LS1). LS1 loading and unloading limestone dust emissions from this silo will also be controlled by FFB DC5. Limestone unloaded from the silo will be transferred to a feed chute by the Limestone Weight Feeder (LC03). The feed chute dumps directly into the Limestone Mills, which feed directly into the furnace of the boiler.

6. Fly and Bed Ash Handling, Transfer, and Storage/Disposal Operations

Combustion of coal in the CFB Boiler will produce two types of dry ash: bed ash (20-30%) and fly ash (70-80%). Both fly ash and bed ash will be dry and will be collected in two separate ash silos. Fly ash collected by the baghouse will be pneumatically transferred to the fly ash silo (AS1). Air displaced by fly ash silo charging will be controlled by Bin-Vent DC6, while bed ash from the CFB Boiler will be transferred pneumatically to the bed ash silo (AS2) where emissions will be controlled by a bin vent DC7. Bed ash and fly ash will be gravity-fed into trucks through a pug mill where water and ash are mixed to reduce dust generation. Air displaced by ash loading into trucks will be vented through AS1 and AS2 and their associated bin vents DC6 and DC7, respectively. The ash will be transferred from AS1 and AS2 to trucks and disposed of in the on-site ash monofill. In addition to disposal on-site, SME-HGS is researching beneficial uses for the ash.

7. Fuel-Oil Storage Tank

The diesel fuel will be used for CFB Boiler startup, shut-down, and commissioning operations, auxiliary boiler operations, emergency generator operations, and emergency fire pump operations, and will be stored in an above-ground fuel tank. The tank will hold up to 275,000 gallons of #2 diesel fuel. The tank will be limited to the storage of fuels with a vapor pressure of 3.5 kilopascals (kPa) or less to avoid 40 CFR 60, Subpart Kb, applicability.

8. Haul Roads

Trucks will be used for the delivery of limestone and the transport of ash to the monofill. The facility will also have bulldozers and front-end loaders, which will be utilized to maintain the emergency coal storage pile. SME-HGS will use reasonable precautions, including water sprays, to reduce fugitive emissions from unpaved work areas and roadways.

9. CFB Boiler Refractory Brick Curing Heaters

SME-HGS formulated a conservative refractory brick curing scenario (i.e., scenario with conservatively high emission rates). This scenario includes a total heat input to cure the CFB Boiler refractory brick that would not exceed the maximum hourly heat input to the CFB Boiler of 2771 MMBtu/hr. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation per year and shall combust only propane fuel.

C. Permit History

The Department issued its preliminary determination on air quality **Permit #3423-00** on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. Further, on April 25, 2006, Bison Engineering, Inc., 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 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 Permit #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 Permit #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 Permit #3423-00 includes the following changes:

- Modification of the mercury emission control requirements contained in Section II.C.14.b to require installation of activated carbon injection (ACI) control technology, or an equivalent technology (equivalent in removal efficiency), prior to commencement of commercial operations and operation of ACI, or an equivalent technology (equivalent in removal efficiency), after a 6 month IECS operational period.
- Modification of the CFB Boiler Start-Up and Shutdown Plan contained in Attachment 3 to Permit #3423-00.
- Modification of CFB Boiler Start-Up and Shutdown requirements contained in Section II.B.1 to allow for future changes to the *CFB Boiler Start-Up and Shutdown Procedures* contained in Attachment 3, upon written approval of the Department.
- Removal of the Start-Up and Shutdown CO emission limit of 194 lb/hr. The Best Available Control Technology (BACT)-determined CO emission limit of 0.10 lb/MMBtu contained in Section II.C.8 is applicable during Start-up and Shutdown operations and has been shown, through modeling, to be protective of the National and Montana Ambient Air Quality Standards (NAAQS and MAAQS).
- Modification of Section II.B.3 to include propane as an allowable CFB Boiler start-up and shutdown fuel. The SME-HGS application for air quality permit did not specifically propose propane as an allowable start-up and shutdown fuel for the CFB Boiler. However, based on the analysis of fuel oil, natural gas, and propane provided by SME-HGS for Auxiliary Boiler operations, the Department believes that propane is a relatively clean burning fuel and is therefore a suitable fuel for CFB Boiler start-up and shutdown operations.
- Modification of the language contained in Section II.E.2 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 DC1 through DC5 based on Department source testing schedule guidance using Department-updated uncontrolled emission estimates for the affected units.
- Removal of the term "belt" from the conveyor transfer requirement in Section II.E.5.

- Modification of Section II.F.3 to remove the requirement that all limestone haul trucks be "covered" during transport. The Department determined that the covering of such trucks does not constitute BACT in this case.
- Removal of the language "…for transfer to the on-site ash monofill/landfill" from Section II.G.4, as this language does not constitute an air quality requirement.
- 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 Permit #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 Permit #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. Modeling is included for both the original and the alternative footprint.
- Removal of all requirements and references to the Acid Rain Program under 40 CFR Parts 72-78. While SME-HGS is subject to the applicable requirements of the Acid Rain Program, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department does not have the authority to include Acid Rain Program provisions in Permit #3423-00.

The HGS air quality permit was appealed to Montana Board of Environmental Review (BER) prior to being issued final on May 30, 2007. 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 particulate matter (PM) with an aerodynamic diameter less than 2.5 microns in diameter ($PM_{2.5}$). 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."

D. Current Permit Action

On June 6, 2008, the Department received an "Addendum to Application for Air Quality and Operating Permits" from SME for Permit #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.

The current permit action is a modification to Montana Air Quality Permit (MAQP) #3423-00 pursuant to the Order issued by the BER in the matter of contested case number BER 2007-07 AQ. The modification establishes 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 has requested to take federally enforceable permit limits for

HAPs in order to avoid major source status with respect to HAPs. Pursuant to this request, emission limitations are included for hydrochloric acid (HCl), hydrofluoric acid (HF), as well as, boiler heat input rate and control technology requirements, as revisions to Section II.A.10; II.B.5 and 6; Section II.C.11, 12, 15, 19 and 20; and Section II.N.1g and h of the permit. Also included are corresponding reporting requirements in Section II.O and notification requirements in Section II.Q.

Permit #3423-01 was issued as a preliminary determination on October 6, 2008, and the public comment period closed on November 5, 2008. The Department received a multitude of comments on the preliminary determination. The Department will respond to comments under separate letter head. The Department has made some changes to the permit conditions based on some comments received. The Department reviewed the limitations used to calculate the potential emissions for establishment of the synthetic minor status below the MACT applicability threshold. The Department has changed the boiler heat input, HCl, and HF limitations to ensure SME has the potential to emit below the major source threshold. The Department has also increased the testing frequency for these pollutants to annually.

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.

3. ARM 17.8.106 Source Testing Protocol. (1) 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). (2) All emission source testing, sampling and data collection, recording, analysis, and transmittal must be performed as specified in the Montana Source Test Protocol and Procedures Manual, unless alternate equivalent requirements are determined by the Department and the source to be appropriate, and prior written approval has been obtained from the Department. If the use of an alternative test method requires approval by the administrator, that approval must also be obtained.

   SME-HGS 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.

   In the SME-HGS application for Permit #3423-00 and in comments submitted by SME-HGS on the Department's preliminary determination on Permit #3423-00, SME-HGS raised the issue of the accuracy of EPA Method 202 and the need for a refined method to monitor compliance with the permitted CFB Boiler PM_{10} emission limit (filterable and condensable). In those comments, SME-HGS indicated that compliance with the proposed

PM_{10} permit limit was tied directly to the use of a refined Method 202 source test. EPA and some states have recognized deficiencies in Method 202 that can produce an inaccurate and unreliable measurement of condensable PM_{10} emissions. EPA currently has an active Work Group studying this issue and intends to provide recommendations to the states on how to deal with the deficiencies in Method 202 and to modify the method to accurately measure emissions, if necessary. In view of the documented potential for problems with Method 202 and SME-HGS' concerns, as expressed in its application and thereafter, the Department has informed SME-HGS that it has authority to approve alternative test methods as part of the source test protocol review process. Approving refinements or alternatives to Method 202 will be considered by the Department through the process outlined in the Montana Source Test Protocol and Procedures Manual.

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 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

SME-HGS 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 (PM). (2) Under this rule, SME-HGS 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). SME-HGS is an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts:

   a. 40 CFR 60, Subpart A. The general provisions provided in 40 CFR 60, Subpart A, apply to all equipment or facilities subject to any Subpart listed below.

   b. 40 CFR 60, Subpart Da. As applicable to CFB Boiler and associated affected equipment.

   c. 40 CFR 60, Subpart Db. As applicable to Auxiliary Boiler and associated affected equipment.

   d. 40 CFR 60, Subpart Y. As applicable to coal processing, handling, and storage equipment and activities.

   e. 40 CFR 60, Subpart OOO. As applicable to limestone processing, handling, and storage equipment and activities.

   f. 40 CFR 60, Subpart HHHH. As applicable under the Montana mercury rules: ARM 17.8.740, ARM 17.8.767, ARM 17.8.771, and ARM 17.8.772.

8. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This source shall comply with the applicable standards and provisions of 40 CFR 61.

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. SME has requested and taken federally enforceable permit limitation such that the HGS is not a major source of HAPs.

   a. 40 CFR 63, Subpart A. The general provisions provided in 40 CFR 63, Subpart A, apply to all equipment or facilities subject to any Subpart listed below:

   b. 40 CFR 63, Subpart ZZZZ. As applicable to the Emergency Generator.

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-HGS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the stacks for the SME-HGS CFB Boiler and Auxiliary Boiler are below the allowable GEP stack height and SME-HGS has demonstrated compliance with all applicable ambient air quality standards as part of the complete permit application for this permit.

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-HGS submitted the appropriate permit application fee for MAQP #3423-00.

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 tons per year of any pollutant. SME-HGS has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, CO, SO_2, and VOC; 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, alteration, or use of a source. SME-HGS 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-HGS submitted an affidavit of publication of public notice for the

December 7, 2005, issue of the *Great Falls Tribune*, a newspaper of general circulation in the town of Great Falls in Cascade County, as proof of compliance with the public notice requirements for the MAQP #3423-00.

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-HGS 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 17.8.760 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.

11. 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 altered 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.

12. 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).

13. 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 Board of Environmental Review (Board) 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.

14. 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.

15. ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units. This rule specifies applicable mercury emission limitation requirements and initial and subsequent application requirements for the adoption of the appropriate mercury emission limitation(s) and determination of mercury control strategies for mercury-emitting generating units.

16. ARM 17.8.772 Mercury Allowance Allocations under Cap and Trade Budget. This rule describes the Department's responsibilities with respect to mercury allowance allocation and timing of allowance allocations and submittal in conjunction with 40 CFR 60, Subpart HHHH for mercury-emitting generating units.

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.

This facility is a listed source because it is a fossil-fuel fired steam-electric generating plant having more than 250 MMBtu/hr heat input capacity. Furthermore, the facility's emissions of PM, PM_{10}, NO_X, SO_2, and CO are greater than 100 tons per year; therefore, the facility is a major source under the New Source Review Prevention of Significant Deterioration (PSD) program.

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 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (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 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (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 major sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3423-00 for SME-HGS, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for PM, PM_{10}, NO_X, SO_2, and CO.

   b. The facility's PTE is less than 10 tons/year for a single HAP and less than 25 tons/year for all HAPs.

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

d. This facility is subject to NSPS requirements under 40 CFR 60, Subparts A, Da, Db, Y, and OOO.

e. This facility is subject to area source provisions of NESHAP standards under 40 CFR 63, Subpart ZZZZ, as applicable.

f. This source is a Title IV affected source.

g. This source is not a solid waste combustion unit.

h. This source is not an EPA designated Title V source.

Based on the above information, the SME-HGS facility is a major source of air pollutants as defined under the Title V operating permit program; therefore, a Title V Operating Permit is required. SME-HGS submitted an application for a major source Title V operating permit concurrent with the submittal of the application for Montana Air Quality Permit #3423-00.

III. BACT Determination

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

Under the current permit action, SME-HGS provided a $PM_{2.5}$ specific top-down BACT analysis in an effort to meet the requirements of the May 30, 2008, BER Order remanding MAQP #3423-00. The following is that BACT analysis as presented by SME. Department has incorporated permit conditions in Sections II. C, O, Q of the permit in accordance with the provided BACT analysis.

Step 1 - Identify All Available Control Options

The first step in a top-down Best Available Control Technology (BACT) analysis is to identify all "available" control options for the pollutant and emission unit in question. The Board of Environmental Review (BER) decision to remand Montana Air Quality Permit (MAQP) #3423-00 specifically states the emission unit in question is the circulating fluidized bed (CFB) boiler. Available control options as defined by the New Source Review Workshop Manual, October, 1990 draft (NSR Manual) include those air pollution control technologies or techniques with a practical potential for application to each regulated pollutant being evaluated. Available control options are further defined as including transferable technologies, foreign technologies, innovative technologies, inherently lower polluting processes, and combinations of control strategies.

Identified Control Technology Descriptions

SME and the Department conducted an extensive search to identify technologies available to control the criteria pollutant $PM_{2.5}$. The search included review of technical journals, texts and independent "white" papers, patent information, research institutions, control technology vendors and boiler manufacturers, the RBLC, other coal-fired power generation facilities, the internet, and published information from state and federal air permitting agencies. Based on the results of this research, the following individual control technologies were identified as potentially possessing a practical potential to control filterable and/or condensable components of $PM_{2.5}$. In addition to listing potential individual technologies, Table 0-1 indicates the $PM_{2.5}$ constituents potentially controlled.

Table 0-1: Individual Potentially Available Alternative Control Technologies For Total $PM_{2.5}$

Control Technology	Primary $PM_{2.5}$ Component Controlled
Coal Cleaning	Acid gases
Alternate Combustion Processes	Condensable and filterable particulate
Flue Gas Desulfurization (wet and dry)	Acid gases and filterable particulate (wet FGD only)
Fabric Filter Baghouse (FFB) including: - Intrinsically coated fabric filters - Membrane fabric filters - Electrostatic fabric filters	Filterable particulate and condensed acid gases Acid gases depending on filter cake condition
Wet Particulate Scrubber	Acid gases and filterable particulate
Cyclones and Inertial Separators	Filterable particulate
Dry Electrostatic Precipitator (DESP)	Filterable particulate
Wet Electrostatic Precipitator (WESP)	Condensable particulate and filterable particulate
Enhanced ESP (laminar flow ESP, membrane wet ESP, bi-polar agglomerator)	Filterable particulate (and condensable particulate if applied to WESP)
Developing Fine Particulate Control Technologies (Powerspan ECO Process, ElectroCore electrostatic centrifuge)	Condensable and filterable particulate

Each of these individual technologies will first be described in this step of the BACT analysis. Then potential combinations of technologies will be addressed.

Coal Cleaning

Coal is a heterogeneous mixture of organic and inorganic matter. The inorganic impurities associated with coal include rocks, overburden (soil), and pyrite (iron disulfide, FeS_2). Sulfur in coal is a potential contributor to the formation of condensable particulate matter. These inorganics can be physically separated to varying degrees through physical coal cleaning. Various coal cleaning processes may be employed to improve coal quality and reduce coal sulfur content.

Alternate Combustion Processes

As described by Babcock & Wilcox for Deseret Power's BACT analysis[1], a supercritical boiler (regardless of combustion process; i.e., Pulverized Coal (PC) -fired, CFB, gas-fired, etc.) is designed to operate with the working medium (water) at a pressure above the critical point [3,200 pound per square inch absolute (psia)]. At this pressure, the medium ceases to boil, or in other words cannot be separated to liquid and steam, thus natural circulation is impossible, and the fluid is pumped through all the heat-absorbing tubes. This increases steam turbine efficiency and would potentially lead to reductions in both fuel input and actual emissions output. However, on a lbs/MMBtu basis, emissions would be expected to be similar to a subcritical unit.

To date, there is only one supercritical CFB boiler in development in the world; it is being developed by Foster Wheeler and is under construction at the Lagisza facility in Poland. At 460 megaWatts (MW), it is the world's largest CFB boiler and approximately double the size of HGS. Commercial operation is scheduled for March 2009. Foster Wheeler has indicated this facility will serve as a demonstration facility to commercialize supercritical CFB technology.

Flue Gas Desulfurization

Flue gas desulfurization (FGD) systems are primarily designed to reduce SO_2 emissions from combustion exhaust and, in doing so, they also reduce emissions of acid gases that contribute to condensable $PM_{2.5}$. There are two primary classifications for FGD systems: wet and dry.

Wet FGD: **Wet flue gas desulfurization (W-FGD) processes mix aqueous alkaline solutions or slurries often containing lime or limestone with combustion exhaust to remove SO_2 and acid gases. Insoluble salts form in the chemical reactions that occur as the reagent comes in contact with the exhaust gas. The salts are then removed as a solid waste by-product that is treated and dewatered. Depending on the type of treatment applied, the solid waste is either disposed of or sold for beneficial use.**

Dry FGD: **Dry flue gas desulfurization (D-FGD) systems rely on the same principles as W-FGD systems to reduce SO_2 and acid gas emissions except they do so without producing a liquid waste stream. Dry FGD systems inject a dry alkaline powder, hydrated limestone, or high-solids slurry into the exhaust stream where the reagent mixes and reacts with SO_2 and acid gases to form solid particles. These are then collected by particulate emissions control equipment and removed. If the particulate emissions control equipment is a fabric filter baghouse (FFB), the FGD reagent collects as a filter cake and continues to react with acid gases in the exhaust stream.**

Fabric Filter Baghouses

An FFB consists of one or more isolated compartments containing rows of fabric filter bags or tubes. The exhaust stream passes through the fabric where the filterable 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. An FFB collects particle sizes ranging from submicron to several hundred microns at gas temperatures up to approximately 500°F. Specialty bags can be used to

[1] Air Pollution Control, 40 CFR 52.2(i), Prevention of Significant Deterioration Permit to Construct, Final Statement of Basis for Permit No. PSD-OU-0002-04.00; August 30, 2007. Deseret Power Electric Cooperative; Bonanza Power Plant, Waste Coal Fired Unit; Uintah & Ouray Reservation; Uintah County, Utah.

achieve lower particulate emission rates or with stack temperatures above 500°F; however, specialty bags cost significantly more than standard bags.
When used downstream of a dry FGD system, the FFB provides additional sulfur oxides control. The alkaline filter cake continues to react with and remove gaseous SO_2 and SO_3 as they pass through the filters. The alkaline filter cake also captures condensed acid gases that may have formed in the exhaust system. Additionally, in the case of HGS, the filter cake would contain activated carbon injected for control of mercury emissions. This collected carbon provides additional mercury emission control.

A wide variety of fabric filter material exists for FFBs. Standard filters are typically made from fiberglass. Specialty bags potentially provide additional emissions control and can withstand unique operating conditions such as high temperature or acidity. Some types of bags and/or baghouse designs potentially provide enhanced $PM_{2.5}$ control and may be appropriately considered for application to the HGS boiler. Baghouse enhancements include utilization of intrinsically coated (IC) fabric bags, membrane bags, and electrostatic fabric filter baghouse technology (ES-FFB). These are described below.
Intrinsically Coated Bags: **As the name indicates, IC bags use fabric made of coated fibers. The coating is typically Teflon® or a similar fluoropolymer material. Besides improving bag durability, the coating reduces the pore size between fibers which improves particulate removal efficiency, especially for smaller particles.**
Membrane Bags: **Membrane bags have a fluoropolymer or similar coating applied to the surface rather than to the individual fibers. Membrane bags contain smaller pore sizes than IC bags and, consequently, provide theoretically higher control efficiency for very small particles. The coating also inhibits filter cake formation. This latter effect generally results in an overall reduction in pressure drop and increase in bag life relative to standard woven bag materials. Reduced filter cake accumulation can also reduce the control effectiveness of other systems, such as alkali injection FGD, that rely on the filter cake for increased reagent-gas contact.**
Electrostatic Fabric Filters: **Electrostatic fabric filter baghouse (ES-FFB) technology has recently been developed through a partnership of the EPA and Southern Research Institute (SRI). The technology is solely licensed to General Electric Energy (GE) and is marketed as the Max-9™ ES-FFB.[2] It is fundamentally an electrostatic pulse-jet fabric filter hybrid. It employs high voltage discharge electrodes to charge particles prior to deposition on the bag filters. Charging the particles theoretically causes them to agglomerate or flocculate, enhancing filtration efficiency of the fabric filter. This technology is also reported to form an "energized" filter cake which may contribute to SO_2 and acid gas control when used downstream of a D-FGD[3]; however, this potential has not been demonstrated in practice. GE reports their ESFFB technology is recommended for use in conjunction with a primary particulate control device; i.e., as a polishing control device for particulate matter.**

Wet Scrubbers
Wet particulate scrubbers use water or an aqueous solution or slurry to impact, intercept, or diffuse a particulate-laden gas stream. When impaction is employed, devices such as venturi nozzles and spray chambers accelerate particles in the gas stream onto a structural surface or into a liquid droplet. In interception type scrubbers, particles flow nearly parallel to the water droplets, allowing the water to intercept, or absorb, the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturi scrubbers employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where the temperature difference between the gas and the scrubbing liquid is large. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

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[2] See http://www.gepower.com/prod_serv/products/particulate_matter/en/max9/index.htm.
[3] Department Personal Communication with Bradley Rogers, GE Power, July 22, 2008

Six particulate scrubber designs are used in wet scrubber 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 three microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets would be needed to trap the particles. This is done at the price of high energy consumption due to hydraulic or velocity pressure losses.[4] **Wet scrubbers used specifically for particulate control are not commonly used on electrical generation utility boilers because of the high pressure drop to remove particulate to levels equivalent to those achieved with an FFB or electrostatic precipitator (ESP). Wet scrubbers are commonly designed for SO_2 removal instead of particulate control. To control only particulate emissions, a wet scrubber generally uses only water as the contact medium. When used to control SO_2 and acid gas emissions, the contact medium is a slurry of water and lime, limestone, or some other alkaline material.**

Cyclones and Inertial Separators

Inertial separators are widely used for the collection of medium size and coarse particles. They are simple in design with few moving parts and have historically been the particulate control work horse of smaller industrial sources. Cyclones in series, often called multiclones, are used for control of smaller particulates. EPA's Air Pollution Control Technology Fact Sheet for Cyclones states that cyclones are used to control PM and primarily particulate greater than 10 microns. However, there are high efficiency cyclones designed to be effective for PM_{10} and $PM_{2.5}$.

Dry ESP

An ESP uses electric forces to move particles out of the gas stream and onto collection electrodes. The particles are given an electric charge by forcing them to pass through the corona that surrounds a highly charged electrode, frequently a wire. The electrical field then forces the charged particles to the opposite charged electrode. Solid particles are removed from the collection electrode by a shaking process known as "rapping."

Dry ESPs (D-ESP) may be configured in several ways. The types discussed below are the plate wire precipitator, the flat plate precipitator, the tubular precipitator and the two-stage precipitator. These descriptions are outlined in the EPA *OAQPS Cost Control Manual* for ESP control.

Plate Wire Precipitator: **The plate wire precipitator is the most common variety. It is commonly installed on 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.**

Flat Plate Precipitator: **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 Precipitator: **Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators are typically used in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants.**

Two-Stage Precipitator: **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 sources emitting submicrometer particulate, oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are specialized types of devices used in very limited applications.**

Wet ESP

Wet precipitators can be configured as any of the four previously discussed precipitators but with wet collection plates instead of dry collection plates. A wet precipitator aids in further collection of particles by preventing the collected particulate from being re-entrained in the exhaust stream

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[4] William Vatavuk, *Estimating Costs of Air Pollution Control*, 1990

during the rapping of the walls, a problem common to dry precipitators. This effect also increases the equipment's effectiveness at removing very small particles. Small particle removal efficiency is also enhanced by the high humidity in the chamber by improving collection of highly resistive particles. A wet ESP (WESP) facilitates removal of condensable particulate because the gas stream must be conditioned to a temperature below about 190°F. The relatively low gas temperature and the high humidity promote condensation of acid gases to aerosol particles which are collected on the ESP's charged surfaces. The major disadvantages associated with WESPs are the complexity and cost of handling the wash water and waste disposal. They are also unable to handle large particulate loads and could not serve as a primary particulate control device on a utility boiler.

ESP Enhancements

Several technologies have been developed to enhance the performance of ESPs. These enhancements include basic design modifications and add-on supplemental equipment. Information was available about the following enhancement technologies.

Indigo Bi-Polar Agglomerator: **The Indigo Agglomerator is installed in the high velocity ductwork upstream of an ESP. It is essentially a gas stream conditioning device designed to enhance the collection efficiency of an ESP. It uses electrostatic and fluidic methods to treat the dust particles prior to entering the ESP. The flue gas is charged half positively and half negatively (bi-polar). The particles are mixed together such that the positive and negative particles adhere to one another. This causes the particles to bind together and create larger particles that are easier to collect in the ESP downstream.[5]**

Membrane Wet ESP: **Membrane wet ESPs use the same electrostatic principles used in traditional wet ESPs, but they utilize polypropylene membranes rather than steel plates as collection surfaces. Field disruptions that occur due to spraying (misting) of water, formation of dry spots (channeling), and collector surface corrosion can limit the effectiveness of standard wet ESPs in the control of condensable $PM_{2.5}$. Researchers at Ohio University have patented a membrane collection surface to address these problems. The membrane collectors are made of corrosion-resistant fibers. Capillary action between the fibers maintains an even distribution of water throughout the membrane. In addition to flushing collected particles, the water acts as the charge-carrying electrode. Pilot test data indicate that a membrane wet ESP is more effective at collecting fine particulates, acid aerosols, and oxidized mercury than a steel plate wet ESP.[6] However, according to a licensed vendor of the technology,[7] installations of these units have only been on industrial facilities, with no utility applications, and no applicable $PM_{2.5}$ emissions performance data have been developed.**

Laminar Flow ESP: **A laminar flow ESP, supplied by Environmental Elements Corporation (EEC), is another identified enhanced ESP technology. The website for EEC, whose name changed in 2005 to Clyde Bergemann EEC (CBEEC), lists several air emissions control products but contains no mention of a laminar flow ESP.[8] SME contacted CBEEC to request information about their laminar flow ESP, but they initially were unaware of any such technology. After some research, one of CBEEC's representatives informed SME that the laminar flow ESP is also known as an agglomerator and is mostly applied to retrofit applications.[9] The laminar flow ESP is installed in conjunction with a traditional ESP and is only compatible with dry ESPs, not wet. Installations in**

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5 See http://www.indigotechnologies.com.au/index.html for more information.

6 "MEMBRANE WESP – A Lower Cost Technology to Reduce $PM_{2.5}$, SO_3 & HG^{+2} Emissions," John Caine and Hardik Shah, Southern Environmental, Inc., published technical paper for 2006 Air & Waste Management Association;
see http://www.southernenvironmental.com/_pdf/Membrane%20WESP_Paper.pdf

7 June 20, 2008 telephone conversation between Jessica Ayers, Stanley Consultants, Inc. and John Caine, Southern Environmental, Inc. See the following website for a Southern Environmental sales brochure: http://www.southernenvironmental.com/_pdf/membraneWESPbrochure.pdf

8 See http://www.eec1.com/company/index.htm.

9 June 25, 2008 telephone conversation between Jessica Ayers, Stanley Consultants, Inc. and Don Hug, Clyde Bergemann EEC.

the U.S. are only at industrial facilities. The vendor indicated the equipment is applied at four utility plants in the United Kingdom, although he was unable to provide any details, performance history, or the names of the plants.

Innovative and Developing Fine Particulate Control Technologies

A review of the literature shows there are developing control technologies that may be applicable for control of $PM_{2.5}$ emissions. These technologies include the ElectroCore® electrostatic centrifuge and the Powerspan Electro-Catalytic Oxidation technology. Following is a brief description of each of these technologies.

Electrostatic Centrifuge: **The ElectroCore® electrostatic centrifuge was developed by Pratt and Whitney as a retrofit technology to be installed downstream of an underperforming ESP. It employs electrostatic and centrifugal forces to concentrate and separate particulate matter from an exhaust stream. The particles are pre-charged and then enter a separation module where the particulate matter is concentrated into an approximately 10% bleed stream. The bleed stream is so named because it is separated or bled from the primary exhaust stream and recycled back to the start of the process or further treated via a small collection device. The remaining 90% of the air flow – now cleaned of particulate matter – is exhausted to the stack.**

Electro-Catalytic Oxidation: **The Electro-Catalytic Oxidation (ECO) technology being developed by Powerspan Corporation (http://www.powerspan.com/home/index.shtml) provides emissions control for gases and particulate matter. The Powerspan website shows the ECO process to be a standard particulate control device (ESP or Fabric Filter) followed by a reactor and scrubber followed by a Wet ESP. This layout is similar to other control equipment configurations presented later in this $PM_{2.5}$ BACT analysis; therefore, this technology, which is still in early commercial scale development, was not specifically evaluated in this analysis. Further, Powerspan claims 95% control efficiency for $PM_{2.5}$, which is in the range of control efficiencies used for similar control equipment configurations in this BACT analysis.**

Technology Combinations

The final process in Step 1 of this top-down BACT analysis is to identify combinations of control technologies, herein called control options. The objective of this BACT analysis is to conduct a comprehensive review of potential control options; however, based on the number of control technologies described above there are in excess of 500 theoretical control technology combinations, or control options. The NSR Manual states that, "it is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emission unit" (page B.20). The Manual also states that, "It is not EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options" (page B.23). The NSR Manual recommends winnowing the control options based on listed decision-making factors included in the Manual and other decision-making factors that are within the discretion of the reviewing authority. Selection of the final list of control options evaluated for the remainder of this $PM_{2.5}$ BACT analysis was guided by the preceding NSR Manual intent statements and the following factors.

A. Two primary objectives were identified in selecting control options for evaluation. The first objective was, as much as possible, to select combinations with the potential for unique contribution in terms of overall control efficiencies and potential for adverse impacts. Many potential combinations would present overlapping benefits and disadvantages. The second objective was to attempt to identify a comprehensive range of alternatives.

B. Many of the individual technologies described above are not completely unique, but rather are refinements or enhancements of some existing technology. As such, they contribute only a marginal improvement in control efficiency, especially if the basic technology is already highly effective. This fact tends to diminish the differences in performance between enhancements. For example, if a base technology has a control efficiency of 95 percent, and an enhancement adds an additional 70 percent, the effective combined control efficiency would be 98.5 percent. If a different enhancement adds 90 percent control, the effective combined control efficiency of that system would be 99.5 percent. Therefore, a 20 percent increase in the enhancement control efficiency would yield only a one percent increase in cumulative effective control efficiency.

C. The selected control options must be technically viable. For instance, it is not technically feasible to operate a wet FGD system upstream of an FFB; the moisture added to the exhaust stream by the wet FGD would cause the FFB to plug and become inoperable. Similarly, control technologies determined to not be technically feasible in Step 2 are excluded from forming control options that are carried forward in the analysis beyond that step.

SME believes that cyclones and inertial separators are not considered modern control technologies, have relatively low control efficiencies and would not be considered in a modern utility boiler control strategy. Based on the preceding guiding principles, cyclones and inertial separators are excluded from further analysis because they are not believed to provide a unique contribution in terms of overall control efficiencies or environmental impacts as a stand-alone control technology, or in combination with other control technologies as a control option.

Table 0-2 presents the list of control options carried forward in this analysis. This selection of alternative control options was suggested by the Department and is much larger than in the BACT analysis originally submitted by SME. SME believes consideration of over 100 alternatives is not appropriate for the following reasons:

D. It is SME's opinion that such a large number of alternatives contravenes the intent of BACT analyses as described in the NSR Manual.

E. Given the limited precision available for estimating control efficiencies, most of the alternatives presented below are nearly indistinguishable in terms of effectiveness. Table 0-4 shows that 74 of the 105 control systems identified are estimated to provide greater than 99 percent control efficiency for total $PM_{2.5}$.

F. Many of the combinations of multiple redundant classes of equipment could not actually be operated due to extreme system pressure drops.

G. Such a large number of alternatives unnecessarily complicates the analysis and tends to obscure the justification for selecting a single best alternative.

Despite these concerns, SME will carry forward in this analysis the Department's recommended set of alternative technologies as requested by the Department.

Table 0-2: Selected Alternate Control Options.

Option #	Technology Combination	Option #	Technology Combination
1	ICFFB	54	DFGD + ICFFB + EWESP
2	MFFB	55	DFGD + ESFFB + WESP
3	ESFFB	56	SDA FGD + ESFFB2 + EWESP
4	DESP	57	EDFGD + ICFFB + EDESP
5	WESP	58	EDFGD + ESFFB + EDESP

Option #	Technology Combination	Option #	Technology Combination
6	EDESP	59	EDFGD + ICFFB + EWESP
7	EWESP	60	EDFGD + ESFFB + EWESP
8	MWESP	61	DFGD + EDESP + MFFB
9	DFGD + ICFFB	62	DFGD + MFFB + EWESP
10	DFGD + ESFFB	63	EDFGD + EDESP + MFFB
11	SDA FGD + ESFFB2	64	EDFGD + MFFB + EWESP
12	DFGD + MFFB	65	DFGD + EDESP + WESP
13	DFGD + DESP	66	EDFGD + EDESP + WESP
14	DFGD + WESP	67	DFGD + DESP + ICFFB + MFFB
15	WFGD + WESP	68	DFGD + ICFFB + MFFB + WESP
16	EDFGD + ICFFB	69	DFGD + ESFFB + MFFB + WESP
17	EDFGD + ESFFB	70	EDFGD + DESP + ICFFB + MFFB
18	EDFGD + MFFB	71	EDFGD + DESP + ESFFB + MFFB
19	EDFGD + DESP	72	EDFGD + ICFFB + MFFB + WESP
20	EDFGD + WESP	73	EDFGD + ESFFB + MFFB + WESP
21	DFGD + EDESP	74	EDESP + ICFFB + MFFB
22	DFGD + EWESP	75	EDESP + ESFFB + MFFB
23	WFGD + EWESP	76	ICFFB + MFFB + EWESP
24	WFGD + MWESP	77	DFGD + ICFFB + DESP + WESP
25	EDFGD + EDESP	78	DFGD + ESFFB + DESP + WESP
26	EDFGD + EWESP	79	EDFGD + ICFFB + DESP + WESP
27	DFGD + ICFFB + MFFB	80	EDFGD + ESFFB + DESP + WESP
28	DFGD + ESFFB + MFFB	81	ICFFB + EDESP + WESP
29	SDA FGD + ESFFB2 + MFFB	82	ESFFB + EDESP + WESP
30	DFGD + ICFFB + DESP	83	DFGD + EDESP + ICFFB + MFFB
31	DFGD + ESFFB + DESP	84	DFGD + EDESP + ESFFB + MFFB
32	SDA FGD + ESFFB2 + DESP	85	DFGD + ICFFB + MFFB + EWESP
33	DFGD + ICFFB + WESP	86	DFGD + ESFFB + MFFB + EWESP
34	DFGD + ESFFB + WESP	87	EDFGD + EDESP + ICFFB + MFFB
35	SDA FGD + ESFFB2 + WESP	88	EDFGD + EDESP + ESFFB + MFFB
36	EDFGD + ICFFB + MFFB	89	EDFGD + ICFFB + MFFB + EWESP
37	EDFGD + ESFFB + MFFB	90	EDFGD + ESFFB + MFFB + EWESP
38	EDFGD + ICFFB + DESP	91	DFGD + ICFFB + EDESP + WESP
39	EDFGD + ESFFB + DESP	92	DFGD + ESFFB + EDESP + WESP
40	EDFGD + ICFFB + WESP	93	EDFGD + ICFFB + EDESP + WESP
41	EDFGD + ESFFB + WESP	94	EDFGD + ESFFB + EDESP + WESP

Option #	Technology Combination	Option #	Technology Combination
42	EDESP + ICFFB	95	DFGD + ICFFB + MFFB + DESP + WESP
43	ICFFB + EWESP	96	DFGD + ESFFB + MFFB + DESP + WESP
44	ESFFB + EWESP	97	EDFGD + ICFFB + MFFB + DESP + WESP
45	DFGD + DESP + MFFB	98	EDFGD + ESFFB + MFFB + DESP + WESP
46	DFGD + MFFB + WESP	99	ICFFB + MFFB + EDESP + WESP
47	EDFGD + DESP + MFFB	100	ESFFB + MFFB + EDESP + WESP
48	EDFGD + MFFB + WESP	101	DFGD + ICFFB + MFFB + EDESP + WESP
49	EDESP + MFFB	102	DFGD + ESFFB + MFFB + EDESP + WESP
50	MFFB + EWESP	103	EDFGD + ESFFB + MFFB + EDESP + WESP
51	DFGD + ICFFB + EDESP	104	DFGD + ICFFB + MFFB + ESFFB + EDESP + WESP
52	DFGD + ESFFB + EDESP	105	EDFGD + ICFFB + MFFB + ESFFB + EDESP + WESP
53	SDA FGD + ESFFB2 + EDESP		

Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of each control option identified in the first step is evaluated with respect to source-specific factors. In making determinations of technical feasibility the NSR Manual gives the following guidance, "…… if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible" (page B-17). SME interprets this to mean that the technology has been deployed in full-scale operation on a CFB boiler. In the absence of this demonstration, determination of technical feasibility is more involved. The NSR Manual indicates that two key concepts must be affirmatively demonstrated in order to determine a technology is technically feasible if it has not previously been deployed at full scale on a similar source. These concepts are *availability* and *applicability*.

The NSR Manual states that a technology may be, "…considered available if it can be obtained by the applicant through commercial channels or is otherwise available in the common sense meaning of the term" (page B-17). As presented in the NSR Manual this means the technology has reached the stage of development including licensing and commercial demonstration. Consequently, technologies in pilot scale testing stages of development would not be considered available for BACT review.

As described by the NSR Manual, determination of the applicability of a control technology is based on technical judgment on the part of the applicant and the reviewing authority. "In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed on the same or similar source type." In the absence of deployment on a similar source type, a demonstration of technical infeasibility should be clearly documented and show that – based on physical, chemical, and/or engineering principles – those technical difficulties would preclude the successful use of the control option for the pollutant under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, "A source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type."

To determine technical feasibility of technologies identified in Step 1, SME and the Department researched technical journals and periodicals, technical fact sheets and other information published by air regulatory agencies, the RBLC, and control equipment vendors and boiler manufacturers. Technical feasibility of control technologies identified in Step 1 is discussed in the following sections for each individual technology and for combinations with other control technologies to form control options.

Coal Cleaning

Full-Scale Deployment at Same Source Type

In the RBLC database, coal cleaning techniques were not specifically identified as a control technique. Many coals may not be amenable to coal cleaning, which is the case for Powder River Basin subbituminous coals and Texas lignite. Cleaning effectiveness would be reduced for Powder River Basin subbituminous coal because it is intrinsically low in sulfur. Accordingly, there is no known full-scale deployment of coal cleaning of PRB coal for use at a CFB boiler. Therefore, this technology has not been demonstrated at full-scale deployment at the same type of source.

Availability

SME reviewed the status of commercial coal cleaning in the region, and finds that commercially cleaned coal is not available. A syncoal facility that once operated near Colstrip was shut down a number of years ago, removing that as a potential fuel source. A process to develop commercially cleaned PRB coal in Wyoming (called Cowboy Coal) is in the development stages, but has not

reached commercial operation.[10] Therefore, cleaned coal is not considered to be available for this project.

Applicability

As discussed in Step 1, coal is a heterogeneous mixture of organic compounds and inorganic impurities. The inorganic impurities associated with coal include rocks, overburden, and pyrite. These inorganics can be physically separated to varying degrees through physical coal cleaning. Sulfur is generally present in coal in three forms: pyritic, sulfate, or organic. The pyritic portion of sulfur in coal may vary from 30% to 70% of the total sulfur content. Large pyrite particles can be removed by physical cleaning. Physical coal cleaning can achieve substantial sulfur reductions on some coals with high pyrite content (50 to 60% for some Northern Appalachia coals); however, not all coals can be effectively cleaned using physical cleaning processes. Sulfate forms of sulfur in coal are usually calcium or iron sulfates, and generally account for less than 0.1% of the coal sulfur content. Subbituminous coals, planned to be used for Highwood Generating Station, have low sulfur content, generally less than or equal to 0.62%[11] and low ash content. Therefore, physical cleaning of pyrite crystals from the coal is not expected to significantly reduce emissions of $PM_{2.5}$ precursors.

Organic sulfur is chemically bound to the coal and cannot be separated by physical coal cleaning but must be removed via chemical leaching. As discussed above, processes are being developed to clean PRB coal; however, these processes are not fully developed and not commercially available. Due to a lack of commercially available cleaned coal and the inapplicability of on-site coal cleaning to remove $PM_{2.5}$ precursors, coal cleaning is eliminated from further analysis as a control technology or part of a control option (see NSR Manual, pages B-17 and 18).

Alternate Combustion Process

Full-Scale Deployment at Same Source Type

One process identified as a potentially cleaner combustion process is a supercritical boiler combustion process. The Department searched the RBLC and located one facility reported to use supercritical combustion, the Wisconsin Public Service – Weston Plant. This boiler is reported to be a supercritical PC-fired unit using natural gas for start-up and secondary fuel. However, the search did not uncover evidence of full-scale deployment of this technology as a control device for filterable or condensable $PM_{2.5}$ from a CFB boiler.

Availability

The only supercritical CFB boiler known to be under construction or proposed is the one at the Lagisza plant in Poland. Foster Wheeler reported to SME that the supercritical design for a CFB boiler is not commercially available in the US market until further operating experience at the Lagisza facility has been gained. Since that facility will not go on-line until 2009, SME concludes this technology is not yet commercially available and should not be considered further in this analysis (see NSR Manual, page B-18).

Applicability

Supercritical CFB boiler technology is not applicable to the HGS project. In addition to being in the commercial development stage, it is compatible only with larger scale generation facilities.

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[10] http://www.fmifuel.com/index.shtml

[11] SME November 30, 2005, Application Materials

FGD

Full-Scale Deployment at Same Source Type
Based on information from the RBLC, both wet, dry, and enhanced dry FGD systems have been deployed as a control technology for a CFB boiler at full-scale operations (i.e., MonDak Utilities – Gascoyne Generation Station; Louisiana Generating, LLC; Sunny Side Ethanol, LLC) and are technically feasible for controlling acid gases from a CFB boiler. Wet FGD systems are also technically feasible for controlling filterable particulate.

Availability
Wet and dry FGD systems are available for use on the HGS CFB boiler.

Applicability
Wet and dry FGD systems are applicable to the HGS CFB boiler.

Limitations
FGD systems are generally at the head of the exhaust stream and intimately germane to the boiler design. Few limitations exist for these technologies with respect to other add-on controls. In general, W-FGD is not used upstream of dry particulate control technology because the humidity added to the gas stream by the W-FGD results in condensation downstream that results in control equipment fouling, malfunction and failure.

FFB

Full-Scale Deployment at Same Source Type
Standard FFB: **Information obtained from the RBLC indicates that standard FFB has been deployed in full-scale operation as a particulate control technology for a CFB boiler process (MonDak Utilities – Gascoyne Generation).**
IC-FFB: **According to Alstom, IC-FFB technology has been deployed in full-scale operation at a CFB boiler (East Kentucky Power Coop., Spurlock Station).**
M-FFB and ES-FFB: **After intensive investigation, no full-scale deployment of an M-FFB or ES-FFB on a CFB boiler has been identified.**

Availability
Standard and IC FFB: **Standard and IC FFBs are available for use on the HGS CFB boiler.**
M-FFB: **M-FFB technology is commercially available from at least two separate manufacturers.**
ES-FFB: **GE, the vendor for the Max 9™ ES-FFB technology, has asserted that their technology is commercially available for purchase and delivery.**

Applicability
Standard and IC FFB: **Standard and IC FFBs are both applicable to the HGS CFB boiler.**
M-FFB: **At least one facility listed in the RBLC will use M-FFB technology as the primary particulate control device applied to a CFB boiler. This facility, Lamar Light and Power in Colorado, is currently under construction. M-FFB is therefore considered applicable for the HGS CFB boiler.**
ES-FFB: **SME contends that ES-FFB technology has not been deployed successfully for enhanced $PM_{2.5}$ removal in full-scale operation on a similar type of facility. The following factors provide justification for this conclusion:**

H. At the time the BACT analysis was initiated (April 21, 2008), the ES-FFB had been in one pilot scale test at Alabama Power's Plant Miller facility, and only in full-scale operation on one boiler, at the Allegheny Energy – R. Paul Smith facility, for approximately three weeks.

I. No data are available to indicate the performance of the Max 9™ relative to removal of $PM_{2.5}$ or any other pollutant in a full-scale, commercial application. The primary objective of installing the equipment at the R. Paul Smith facility was to reduce opacity.

J. The R. Paul Smith facility uses a PC boiler that is approximately one third the size of the HGS CFB boiler.

K. No FGD system is in use at the R. Paul Smith facility. The HGS facility uses a fluidized bed with limestone injection along with humidified ash reinjection to control emissions of SO_2, acid gases, and mercury.

L. Permit limits for SO_2 and PM_{10} emissions at the Paul Smith facility are significantly higher than existing limits for those pollutants at the HGS.

M. According to Stanley Consultants, the design contractor for the HGS facility, particle loading of the gas stream leaving the HGS boiler will be approximately 37 times greater on a mass basis and over 12 times greater on a concentration basis than particle loading in the R. Paul Smith PC boiler exhaust. HGS boiler exhaust will contain up to 9000 times more particulate than the exhaust in the Plant Miller pilot test – the only coal combustion application for which exist any emissions control performance data. HGS's high particulate loading results from the CFB combustion process, entrainment of the limestone and lime in the boiler's fluidized bed, and from recycled injection of hydrated alkaline material for sulfur removal.

N. In addition to adding significant amounts of particulate, the reinjection of hydrated alkaline material increases the humidity of the exhaust stream. This could have a significant effect on the performance of the ES-FFB.

O. According to Alstom Power Systems, the designers of the HGS CFB boiler and currently permitted emissions control system, there is a significant difference between a PC and a CFB boiler in the particle size of the ash. Alstom estimates the average ash size at a PC boiler is 10 microns and around 100 microns for a CFB boiler. This is because, in a CFB boiler, the incoming coal size is much larger and limestone is added to the furnace.

P. GE has indicated that the Max 9™ is being marketed as a polishing control device that would be added after primary particulate control equipment. Its primary advantage is a reduced pressure drop and reduced footprint relative to standard FFBs in some applications.

Q. GE has also indicated that, if the Max 9™ were to be used in place of the currently required baghouse at the HGS facility, another control device would be required upstream in the exhaust system to remove a large fraction of the particulate matter.

These facts lead SME to conclude the Max 9™ has not been "deployed *successfully*" in any full-scale operation. While this criterion is problematic due to the lack of a definition of "success," there is no basis to deem success in relation to control of any air pollutant without test data. More importantly, the differences between the R. Paul Smith and the HGS facilities prove that the Max 9™ has not been employed on a "similar type of facility." Furthermore, the vast difference in exhaust particulate loading between the facilities indicates that the physical characteristics of the boiler exhast streams are not similar.

The Department has indicated they do not concur with these conclusions. Department representatives have stated that they consider deployment at the Allegheny Energy – R. Paul Smith facility a full-scale deployment at a similar facility with sufficiently similar physical and chemical exhaust characteristics. One of the factors they have reported as supporting their conclusion is GE's claim that the Max 9™ functions as a standard baghouse when no power is applied to the

electrostatic system. Department personnel have also contended that exhaust stream differences between the R. Paul Smith and the HGS boilers would not materially affect the results of application at the HGS. They point to a statement made by a GE representative during a July 22, 2008, telephone conversation that this technology is an enhanced baghouse technology that is applicable to coal-fired utility boilers.

SME agrees that the Max 9™ may in theory be applicable to the HGS CFB boiler as a stand-alone, standard baghouse, though with $PM_{2.5}$ removal efficiency possibly less than that for a standard baghouse due to the requirement for a relatively low-mass filter cake. It may also be applicable as a polishing device following primary particulate removal equipment. But it has not been proven to provide enhanced particulate removal as a primary control device in a commercial application. Given the Department's position on this technology, and strictly for the purpose of finalizing this BACT analysis, SME will carry the Max 9™ forward into the next step of this BACT analysis to determine the result were the technology to be deemed technically feasible as a stand-alone, enhanced $PM_{2.5}$ removal system.

Limitations
FFB technology is not applicable downstream of a wet FGD or other wet processes. Moisture in the exhaust gas will wet and ultimately plug the bag filters.

Wet Particulate Scrubber

Full-Scale Deployment at Same Source Type
Queries of the RBLC did not uncover evidence of full-scale deployment of this technology as a control device for particulate matter on a CFB boiler.

Availability
Internet searches indicated that numerous vendors have commercially available versions of this technology for control of fine particulate matter.

Applicability
SME reviewed Air Pollution Technology Fact Sheets published by EPA[12] for general information about wet scrubbers. Of the eight wet scrubber types described, all are typically applied to sources with relatively low exhaust flow rates. The three with the largest capacity are spray chamber/spray tower, venturi, and fiber-bed scrubbers. These are typically applied to sources with exhaust flow rates up to 100,000 scfm. These limitations were confirmed by reviews of design capacity documentation from numerous wet scrubber vendors.[13] The design capacity exhaust flow rate for the HGS CFB boiler is over five times the highest capacity for wet scrubbers. This technology is considered to be technically infeasible based on the physical characteristics of the pollutant-bearing gas stream, and is excluded from further analysis (see NSR Manual, page B-18).

Electrostatic Precipitators

Full-Scale Deployment at Same Source Type
AP-42 (Section 1.1.4.1) lists ESP technology as one of the principle particulate emission control technologies available. At least one facility (AES Puerto Rico-Cogeneration Plant) is listed in the RBLC as having deployed ESP technology on a CFB boiler. Therefore, both wet and dry ESP technologies are determined to be technically feasible.

Availability
Standard ESPs are commercially available.

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[12] Available on the internet at http://www.epa.gov/ttn/catc/products.html.

[13] See http://www.ceilcoteapc.com/prdct_ionizing_wet_scrubber.htm for example

Applicability
Standard ESPs are applicable to the HGS CFB boiler.

Limitations
Conventional D-ESP may only be operated downstream from dry scrubbing processes, such as D-FGD and/or ED-FGD. A W-ESP can be operated downstream of a wet or dry control device. Alstom has reported, however, that W-ESP is only applicable as a polishing or secondary device and cannot handle the full particulate load from a CFB boiler.

ESP Enhancements

Full-Scale Deployment at Same Source Type
Searches of the RBLC and contact with vendors indicates none of the ESP enhancements discussed in Step 1 has been deployed in full-scale operation to control $PM_{2.5}$ from a CFB boiler.

Availability
Based on searches of vendor web pages, telephone conversations and e-mail correspondence with Indigo Technologies, Southern Environmental, and Clyde Bergmann, SME has determined that all three of the ESP enhancements presented in Step 1 are commercially available.

Applicability
Agglomerator: **Technical literature provided by Indigo indicates the Bipolar Agglomerator™ technology has been successfully deployed at coal-fired utility boiler power generation facilities, specifically a 250 MW facility, Southern Company - Watson Plant. The general similarity of the boiler size and expected exhaust quantity and quality from the Watson Plant and HGS CFB indicates this technology is an applicable ESP enhancement for the HGS CFB boiler. Further, the agglomerator enhancement technology is applicable to both wet and dry ESP technologies.**
Membrane Wet ESP: **SME contacted the manufacturer of the membrane wet ESP (Southern Environmental) to ask about performance history. SME reported that pilot testing has been performed at two facilities in the US (FirstEnergy's Bruce Mansfield Plant and Georgia-Pacific's Cedar Springs Mill). Southern Environmental claimed there are four operating membrane wet ESPs though none is at a utility boiler. The membrane wet ESP is specifically designed to be the secondary or "polishing" particulate filtration device in a wet scrubbing system.**
Information posted on Southern's web page indicates that the first commercial full-scale deployment of this technology was at the Smurfit-Stone Container, Stevenson (PA) Plant. At this facility the technology was applied to two industrial boilers burning #6 fuel oil with 4% sulfur content. The technology has been successfully deployed after a W-FGD on a high sulfur coal-fired power generation utility boiler. This technology is deemed applicable as a W-ESP enhancement for controlling $PM_{2.5}$ from the HGS CFB boiler because the particulate loading rate and other exhaust characteristics are expected to be sufficiently similar to the successful coal-fired utility deployment advertised by Southern Environmental.
Laminar Flow ESP: **Even after discussions with the company that owns the license for the laminar flow ESP, insufficient information is available to determine applicability of this technology to the HGS CFB boiler. In the absence of such information, SME will assume the technology is not applicable but will be represented in this analysis by one or more of the other ESP enhancement technologies.**

Limitations
The agglomerator and membrane ESP enhancements are carried forward in the analysis as enhancements only. The Indigo Agglomerator is applicable as an enhancement to either dry ESP or a wet ESP. The membrane ESP system requires a saturated exhaust stream to be effective, and will not function in a satisfactory manner on a non-saturated exhaust stream. Therefore, membrane ESP is carried forward as a wet ESP enhancement that is only applicable downstream of wet scrubbing processes, such as W-FGD.

Innovative and Developing Fine Particulate Control Technologies

Full-Scale Deployment at Same Source Type
RBLC database queries provided no evidence of full-scale deployment of either electrostatic centrifuge or electro-catalytic oxidation as a control technology for particulate matter on a CFB boiler.

Availability
Electrostatic Centrifuge: **Two pilot tests have been undertaken using the ElectroCore electrostatic centrifuge – one in 2001 at Alabama Power Company's Gaston Steam Plant, and the other in 2006 at an Alabama power plant. The pilot test performed in 2006 evaluated an ElectroCore in conjunction with a spray dryer. No test results were available for this pilot test. The *Electric Power Research Institute (EPRI) 2007 Portfolio for Particulate and Opacity Control* describes the ElectroCore as a promising emerging technology. More pilot testing has been scheduled.[14] An internet search for information on the ElectroCore yielded nothing beyond information about the pilot test. Attempts to speak with the vendor for updated information were unsuccessful. A technology that is in the pilot testing stage is not commercially available (see NSR Manual page B-18).**
Electro-Catalytic Oxidation: **Pilot testing using Powerspan's ECO has been performed at FirstEnergy's R.E. Burger Generating Station, but full-scale operation using ECO has yet to be demonstrated. A full-scale ECO process is planned at Units 4 and 5 of the Burger Plant, with design having started in 2007 and operation expected to begin in 2011. The technology is therefore not yet commercially available (see NSR Manual, Page B-18).**

Applicability
Insufficient data were available to determine applicability of either the electrostatic centrifuge or electro-catalytic oxidation technologies to the HGS CFB boiler.

Technical Feasibility Summary
Table 0-1 summarizes the results of the technical feasibility evaluations described above.

[14] See: http://www.pw.utc.com/vgn-ext-templating/v/index.jsp?vgnextoid=8ae5ae1af7c7f010VgnVCM100000c45a529fRCRD

Table 0-1: Summary of Technical Feasibility Determinations

Technology	Full-Scale CFB Application	Available	Applicable	Technically Feasible
Coal Cleaning	No	No	No	No
Alternate Combustion Processes	No	No	No	No
FGD	Yes	Yes	Yes	Yes
Standard FFB	Yes	Yes	Yes	Yes
IC-FFB	Yes	Yes	Yes	Yes
M-FFB	No	Yes	Yes	Yes
ES-FFB	Footnote [15]	Yes	Footnote 15	Footnote 15
Wet Particulate Scrubber	No	Yes	No	No
Electrostatic Precipitators	Yes	Yes	Yes	Yes
Agglomerators	No	Yes	Yes	Yes
Membrane Wet ESP	No	Yes	Yes	Yes
Laminar Flow ESP	No	Yes	Footnote [16]	No
Electrostatic Centrifuge	No	No	Footnote 16	Footnote 16
Electro-Catalytic Oxidation	No	No	Footnote 16	Footnote 16

[15] As noted above, SME concludes that ES-FFB, as an enhanced particulate control technology, has not been successfully demonstrated at a similar facility and is not applicable to the HGS CFB boiler. Due to the Department's contrasting position, ES-FFB technology will be included in the remainder of this analysis as if it were technically feasible.

[16] Insufficient information exists to make a determination of applicability.

Step 3 - Rank Remaining Options by Control Effectiveness

In Step 3, control technology options determined to be technically feasible in Step 2 are ranked in order of pollutant removal effectiveness and/or pollutant emission rate. The control option that results in the highest pollutant removal value or lowest pollutant emission rate is considered the "top" control option. In order to determine control efficiencies for different technologies, parameter concentration and loading rates must be quantified before and after the control device. Primary $PM_{2.5}$ emissions from the HGS CFB boiler are difficult to characterize because EPA has not finalized their testing methodologies for filterable and condensable portions of $PM_{2.5}$. In a May 8, 2008, e-mail to stakeholders (see Appendix B), EPA's Ron Myers announced the posting of revised methods for measuring filterable PM_{10} and $PM_{2.5}$ (OTM-27), and condensable particulate matter (OTM-28) on EPA's website. Comments were solicited on both methods through June 27, 2008. A review of currently promulgated EPA test methods shows no listings for $PM_{2.5}$. Clearly, EPA is still in the development phase for standard test methods for $PM_{2.5}$. As a result, reliable emissions information on $PM_{2.5}$ emissions before and after controls is still lacking.

For example, EPA's AP-42 Chapter 1.1 for bituminous and subbituminous coal combustion lists particle sizing data for several types of coal-fired boilers in Tables 1.1-6 through 1.1-11. The data were gathered using cascading impactors, a method which differs from EPA's proposed filterable test method for $PM_{2.5}$. EPA acknowledges some of the shortcomings of cascade impactor sizing data in the background document for Chapter 1.1 of AP-42 (see pgs. 3-10 to 3-13):

R. Particle bounce and re-entrainment;
S. Diffusive deposition of fine particles;
T. Deposition of condensable/adsorbable gases;
U. Losses to the impactor walls.

No information is presented in the tables for CFB boilers, which differ significantly in design from the other boilers listed. Alstom indicated that no specific reference method test data on $PM_{2.5}$ emissions are currently available for any of their CFB boilers.[17]

Due to this lack of available information for emissions upstream and downstream of devices, control efficiencies are estimated for this analysis based on the chemical and physical properties of the constituents that comprise $PM_{2.5}$, as discussed in Step 1. In the following paragraphs, estimated potential control efficiencies for primary filterable and condensable $PM_{2.5}$ are presented, along with the basis for the estimations, for each remaining technically feasible control alternative.

Flue Gas Desulfurization

W-FGD

SME stated that wet FGD systems can achieve SO_2 control efficiencies of approximately 90 to 98 percent according to an EPA Air Pollution Control Technology Fact Sheet for wet FGD technology.[18] They are significantly less efficient at controlling condensable emissions because they actually create fine aerosol particulates, although these emissions are partially mitigated by inclusion of a mist eliminator with the system. The fact sheet does not provide an estimated control efficiency for acid gases. In its 2007 Statement of Basis for the Deseret Power Electric Cooperative air quality permit,[19] EPA concludes that a wet scrubber that is not followed by a particulate control device is not an effective control technology for condensable particulate emissions. They

[17] SME Application Materials, July 2, 2008, "SME Response to MDEQ June 18, 2008 Memorandum PM2.5 BACT Submittal Review Summary", pg 4.

[18] EPA-452/F-03-034, "Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers."

[19] Air Pollution Control, 40 CFR 52.21(i), Prevention of Significant Deterioration Permit to Construct, Final Statement of Basis for Permit No. PSD-OU-0002-04.00; August 30, 2007. Deseret Power Electric Cooperative; Bonanza Power Plant, Waste Coal Fired Unit; Uintah & Ouray Reservation; Uintah County, Utah.

also note that, "…because of the inherently low SO_3 concentration in CFB flue gas, it is not anticipated that a wet FGD system will provide any significant reduction in overall SO_3 or H_2SO_4 emissions" (page 71). On this basis, SME conservatively assumed a condensable $PM_{2.5}$ control efficiency of 80 percent.

SME stated that information was not readily available to directly indicate potential wet FGD control efficiency for filterable particulate matter in any size range. For the purpose of developing an estimate for this application, SME considered particulate control efficiencies for non-FGD wet scrubbers. A wet FGD system is most similar to a spray chamber or spray tower scrubber. An EPA Air Pollution Control Technology Fact Sheet for this type of system[20] indicates potential particulate control efficiencies of 70 percent to over 99 percent. The fact sheet also states that, "Spray tower scrubbers generally are not used for fine PM applications because high liquid to gas ratios…are required." Non-FGD wet scrubbers are also typically limited to applications with no more than 100,000 scfm of air flow, approximately one-fifth the maximum design exhaust of the HGS boiler. Accordingly, SME assumed a conservatively high filterable $PM_{2.5}$ control efficiency of 80 percent.

D-FGD

Based on the November 2005 air quality permit application submitted by SME, the Department determined BACT limits for HGS boiler emissions of SO_2, total PM_{10}, H_2SO_4, HCl, HF, and mercury based on combustion of low-sulfur coal, within a CFB boiler with limestone in the combustion bed, hydrated ash reinjection (HAR), and an FFB with intrinsically coated (IC) fabric. For the purpose of this $PM_{2.5}$ analysis, low-sulfur coal combustion and limestone CFB are considered as part of the applicant defined source, which is not subject to BACT analysis. HAR D-FGD will be evaluated for $PM_{2.5}$ control effectiveness. Dry FGD scrubbers provide no filterable $PM_{2.5}$ control but rather add to the particulate matter concentration in the exhaust stream. However, D-FGD scrubbers are followed by particulate control devices, most commonly an FFB, forming a system to control acid gases and particulates.

SME conducted an extensive internet review for information related to potential condensable $PM_{2.5}$ control efficiencies for dry FGD systems. The search yielded a wide range of efficiencies, from 15 to 95 percent. According to an EPA Air Pollution Control Technology Fact Sheet for dry FGD technology,[21] dry FGD can achieve SO_2 control efficiencies on the order of 90 percent. In the case of the HGS CFB boiler, the expected control efficiency for SO_2 would be lower since SO_2 concentrations coming from the limestone combustion bed will be significantly less than concentrations expected from other types of boilers without intrinsic SO_2 control. Assuming condensable $PM_{2.5}$ control efficiency for dry FGD is similar to SO_2 control, and discounting for relatively low inlet concentrations, SME assumed a 75 percent condensable $PM_{2.5}$ control efficiency for its analysis.

ED-FGD

The enhanced dry FGD (ED-FGD) system analyzed for this BACT determination consists of HAR with a separate dry sorbent injection system. Dry sorbent injection would improve control of condensable $PM_{2.5}$ by increasing the alkaline material in the exhaust stream with injection of fresh hydrated lime.

SME assumed an approximate 15 percent improvement from the dry sorbent injection enhancement, resulting in an effective efficiency of approximately 79 percent for the ED-FGD system.

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[20] EPA-452/F-03-016, "Spray-Chamber/Spray-Tower Wet Scrubber."

[21] EPA-452/F-03-034, "Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers."

Fabric Filter Baghouse

IC-FFB

As the name indicates, IC bags use fabric made of coated fibers. The coating is typically Teflon® or a similar material. Besides improving bag durability, the coating reduces the pore size between fibers which improves particulate removal efficiency, especially for smaller particles.

Filterable particulate control is potentially very high for FFBs. SME stated that, according to an EPA Air Pollution Control Technology Fact Sheet for FFBs,[22] potential control efficiency is between 99 and 99.9 percent, though size-specific efficiencies are not provided. For the purpose of its analysis, SME assumed a filterable $PM_{2.5}$ control efficiency of 99.5 percent for IC-FFB.

FFB technology provides no intrinsic control of vapor-phase condensable particulate emissions since these exist as vapors that cannot be mechanically filtered. As noted above, a filter cake collected on the filter surfaces can help control vapor-phase acid gas condensable emissions depending on the physical and chemical characteristics of the filter cake. SME stated that because an FFB will always be used in conjunction with a dry FGD system, for its analysis, a 30 percent vapor-phase condensable $PM_{2.5}$ control efficiency was applied for IC-FFB technology.

M-FFB

Membrane filters are a specialized bag technology with reported increased filtering efficiency for fine particulate. Membrane bags laminate a Teflon™-like membrane to a felt or fiberglass bag. In bench scale tests performed at EPA's Air Pollution Control Technology Center, these bag types show impressive control efficiencies for fine particulate matter.[23]

SME contacted two of the primary membrane bag vendors in the country (GE Energy and W.L. Gore through Midwesco Filter Resources Inc.) to ask about performance history. One of the vendors claimed they have installed a membrane FFB on a coal-fired utility boiler but could not divulge the name of the facility. The other vendor also mentioned application of membrane bags on a large utility boiler. However, that vendor similarly could not provide emissions information or performance for $PM_{2.5}$, sulfur oxides or acid gas control efficiencies, or performance on mercury control.

Although SME did not find $PM_{2.5}$ specific information for membrane bags, SME estimates a 99.9 percent control efficiency for filterable $PM_{2.5}$ based on the different properties and configuration of membrane filter bags and vendor estimates.

Of primary concern regarding membrane bags is their ability to adequately build and maintain a filter cake of ash and SO_2 scrubbing media (e.g., unreacted lime). SME asserts this is necessary to achieve BACT limits for SO_2. The filter cake also contains activated carbon particles that will be injected for control of mercury emissions; without an adequately maintained filter cake, mercury emissions could exceed their permitted limit.

The RBLC lists one coal-fired utility that is required to use an M-FFB, the Lamar Light and Power facility in Colorado. This facility is a 501 MMBtu/hr (compared to 2770 MMBtu/hr max capacity at HGS facility) coal-fired sand bed CFB boiler permitted to use limestone injection for SO_2 control and a membrane baghouse as a primary particulate control device. The Colorado Department of Health and Environment (CODHE) has indicated that this facility is under construction and not yet operational. Neither CODHE nor the project owners were able to satisfy requests for operational and design parameters such as control efficiencies for SO_2 and filterable and condensable $PM_{2.5}$ because the data are not yet available.

Based on CODHE's permit analysis, it appears as though M-FFB with limestone injection was the top control option and selected by the facility as BACT for SO_2 and PM/PM_{10}. Projected acid gases and other condensable emissions were not subject to BACT for this permitting action. Therefore, the analysis contained limited useful technology performance information, cost effectiveness, energy effectiveness or environmental impact information applicable to this BACT analysis. The

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[22] EPA-452/F-03-025, "Fabric Filter – Pulse-Jet Cleaned Type (also referred to as Baghouses)."

[23] website (www.epa.gov/etv/vt-apc.html#bfp),

Lamar permit includes a 24-hour limit for SO_2 of 0.1030 lb/MMBtu; this is over two times greater than the 0.048 lb/MMBtu limit applied to the HGS boiler.
Based on the preceding discussion, a zero percent vapor-phase condensable $PM_{2.5}$ control efficiency for membrane FFB is assumed.

ES-FFB
GE reports that this technology creates on the bag filters an energized dust cake that is less dense than a standard baghouse filter cake. This phenomenon reportedly results in smaller pressure drops compared to standard fabric filter applications. GE also claims the technology could potentially enhance acid gas, SO_2 and SO_3 scrubbing, although no test results are available to verify this claim. GE estimates a control efficiency as high as 99.999% for particulate matter and an 80-90% control efficiency for sub-micron particulate. These estimates are based on a pilot-scale demonstration at a power plant in the southern US.[24] As explained in a previous section, there are extreme differences in total volume and concentration of particulate between the exhaust streams in the pilot demonstration and the HGS boiler. The unit has been deployed commercially on one 87 MW power station (Allegheny Power – R. Paul Smith) and on two industrial boilers. No data are available to indicate system performance in these applications.
The permitting action to install the ES-FFB at the R. Paul Smith facility was not considered a major modification, and so no BACT analysis was conducted. The Department contacted the R. Paul Smith facility on July 22, 2008, with a request for available emissions monitoring data for filterable and condensable $PM_{2.5}$. Return correspondence from the facility indicated emission data were not available as the plant had been operating the ES-FFB for less than 3 months[25].
In the absence of applicable performance test data for the ES-FFB, $PM_{2.5}$ control efficiency must be estimated based on engineering judgment that considers pertinent design and exhaust stream characteristics and related experience with similar applications and pollutants. Some of these factors that were evaluated and discussed by the Department, SME, and its contractors are as follows:

- Charging fine particulate matter in the exhaust stream has been shown to result in agglomeration of submicron particles and improved capture efficiency on the baghouse filters.

- As noted earlier, the average size of ash particle from a PC boiler is 10 microns and around 100 microns for a CFB boiler. This difference could significantly affect the electrostatic performance of the Max 9™, though to an unknown degree.

- GE reports that the charged particles form a filter cake that is "energized" and is less dense than standard baghouse filter cakes. The lower density, which is presumably related to increased porosity, could improve acid gas and SO_2 removal rates by providing additional active alkaline material surface area. Conversely, it could reduce removal rates for these pollutants by reducing the frequency of contact between pollutant and reagent. The residual charge on the collected particles – presumably resulting in the "energized" cake – could exert either an attractive or a repelling force on particles passing through the cake. The magnitude and direction of this effect, if it exists, is unknown.

- Increased humidity in the HGS stream from hydrated ash reinjection would likely change the performance experienced to date for the Max 9™. The magnitude and direction of change, however, are unknown.

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24 See http://www.gepower.com/prod_serv/products/particulate_matter/en/max9/ops_ove_tr.htm.
25 Electronic mail correspondence from Allegheny Power representative Mr. James Lefik, July 25, 2008.

- Relative to conditions in pilot scale and commercial applications of the Max 9™, the HGS system has significantly increased volumes and concentrations of particulate matter. This realization prompted much discussion between the Department, SME's contractors, and GE. GE indicated that the Max 9™ would not operate effectively with the high particulate loading that will result from the currently permitted hydrated ash reinjection (HAR) system. Two potential solutions to this problem were developed.

  The first solution was to include upstream of the Max 9™ an exhaust conditioning device that would remove approximately 60 percent of the mass of particles in the exhaust stream. GE felt that this would reduce the inlet particulate loading experienced by the Max 9™ to an acceptable level. The disadvantage to this configuration is that the mass of reactive alkaline material in the filter cake would be reduced by 60 percent, and the system would presumably suffer a commensurate loss in control efficiency for SO_2, acid gases, and mercury.

  The second proposed solution was to replace the HAR system with a spray dry absorber (SDA) system. The increased reactivity of moist lime in the SDA could presumably achieve desulfurization levels equivalent to the HAR system with a lower mass of reagent. This would theoretically allow a lower filter cake mass without a loss of SO_2 and acid gas control. For the purpose of this analysis, it was assumed that activated carbon injection could be increased to maintain mercury emissions control without significantly affecting total filter cake mass.

It is apparent from the preceding discussion that there are many obstacles and very little basis for an accurate estimate of $PM_{2.5}$ control efficiency for the application of the Max 9™ on the HGS CFB boiler. For that reason, the Department requested that SME's design engineering company, Stanley Consultants, apply their experience and expertise toward making an estimate. Stanley representatives complied with three separate estimates[26]:

V. Filterable $PM_{2.5}$ control efficiency is estimated to be 99.6 percent. This value assumes a 0.1 percent improvement in the filterable $PM_{2.5}$ control efficiency estimated for an IC-FFB.

W. Condensable $PM_{2.5}$ control efficiency is estimated to be 30 percent when used in conjunction with an SDA FGD system. This value assumes condensable $PM_{2.5}$ efficiency equivalent to the value estimated for an IC-FFB and an HAR FGD system.

X. Condensable $PM_{2.5}$ control efficiency is estimated to be 10 percent when used in conjunction with a primary particulate removal device and an HAR FGD system. This value assumes a 60 percent reduction in condensable $PM_{2.5}$ efficiency relative to the value estimated for an IC-FFB and an HAR FGD system. An efficiency reduction of 60 percent corresponds to a 60 percent reduction in filter cake mass.

Electrostatic Precipitators

Dry ESP

SME submitted that D-ESPs may be used downstream of a D-FGD unit to collect the dry FGD media and the ash formed during fuel combustion. Unlike W-ESPs, D-ESPs do not enhance SO_2 or acid gas control. According to EPA's Air Pollution Control Technology Fact Sheet, D-ESPs are estimated to control 96 to 98% of $PM_{2.5}$ emissions.[27] For its analysis SME estimated D-ESP to have

[26] September 3, 2008 letter from Mark Payne of Stanley Consultants to Paul Skubinna, MDEQ

[27] EPA-452/F-03-028, "Dry Electrostatic Precipitator (ESP) – Wire-Plate Type."

an average filterable $PM_{2.5}$ control efficiency of 97.7%, and did not expect D-ESP to contribute to secondary SO_2 or acid gas scrubbing as is expected for FFB applications.

Wet ESP

Wet ESPs have been reported to provide significant control of both filterable and condensable fine particulate emissions. Potential filterable emissions control efficiencies will be evaluated first. An EPA Air Pollution Control Technology Fact Sheet for wet ESPs[28] reports $PM_{2.5}$ control efficiencies of 90.0 to 99.2 percent for various industrial applications, although it does not list utility boilers among the typical industrial applications. The fact sheet does not specify whether it is referring to total or filterable particulate emissions, but an exclusive consideration of filterable emissions is implied. It does note that the technology is typically limited to applications with gas stream volumes between 100,000 and 500,000 scfm; the maximum design exhaust for HGS is at or above the high end of this range.

A report of wet ESP improvements undertaken at the AES Deepwater cogeneration plant to reduce visible emissions[29] provides measured control efficiencies for both filterable and condensable particulate. They report that "…the WESP also removed filterable flyash in the order of 90%..." Because the wet ESP followed a dry ESP, $PM_{2.5}$ can be assumed to comprise most of the fly ash removed in the wet ESP.

SME located a paper published by Wheelabrator Air Pollution Control, Inc., that reported measured control efficiencies for a wet ESP.[30] Based on tests conducted in 2001 and 2003, $PM_{2.5}$ removal efficiency was reported to be between 93 and 96 percent using a pilot-scale wet ESP acting on a slipstream from an 835 MW utility boiler. Reference to filterable $PM_{2.5}$ is assumed since SO_3 control efficiency is reported separately.

Based on these published reports, SME estimated a potential filterable $PM_{2.5}$ control efficiency of 96 percent for wet ESP.

EPA's wet ESP fact sheet referenced above does not provide an estimate of control efficiency for condensable particulate emissions.

The AES Deepwater facility test report referenced above concludes that 90 percent control of sulfuric acid mist is "achievable." The investigators' primary interest was the reduction of SO_3 that was contributing to unacceptable visible emissions. One can assume that the control efficiency for all condensed acid gases – and, by extension, condensable particulate – would similarly be near 90 percent or better.

The above-referenced Wheelabrator technical paper reported SO_3 emissions control efficiencies of between 88 and 92 percent. Again, control efficiencies for total condensable particulate emissions can be assumed to be in the same range.

EPA's 2007 Statement of Basis for the Deseret Power air quality permit estimates an 86 percent control efficiency for condensable PM_{10} provided by wet ESP. This can be assumed to be equivalent for condensable $PM_{2.5}$.

Based on these published reports, SME estimated a potential vapor-phase condensable $PM_{2.5}$ control efficiency of 90 percent for wet ESP.

Enhanced Electrostatic Precipitators

Bi-Polar Agglomerators have been reported to significantly increase control of filterable fine particulate emissions from ESPs. They have been installed at twelve facilities world-wide, including five in the United States. Extensive testing performed at the 250 MW, coal-fired Watson power

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[28] EPA-452/F-03-030, "Wet Electrostatic Precipitator (ESP) – Wire-Plate Type."

[29] "Performance Evaluation of Wet Electrostatic Precipitator at AES Deepwater," Ron Triscori, *et al*., June 2007, see http://www.babcock.com/library/pdf/BR-1796.pdf.

[30] "SO_3 Control and Wet ESP Technology," James "Buzz" Reynolds, Wheelabrator Air Pollution Control Inc., published in the Proceedings of the 2006 Environmental Controls Conference, U.S. Department of Energy, National Energy Technology Laboratory; see http://www.netl.doe.gov/publications/proceedings /06/ecc/pdfs/Reynolds_Summary.pdf.

plant in Mississippi showed a significant reduction in $PM_{2.5}$ emissions. Over a 90% reduction in sub-micron emissions and over 80% reduction in $PM_{2.5}$ emissions from the electrostatic precipitator equipped with the Indigo Agglomerator were reported during testing that continued for over three years.[31] Based on this data, SME estimates that dry ESP enhanced by the Indigo Agglomerator (ED-ESP) will have filterable $PM_{2.5}$ control efficiency of 99.5%; and, a 99.2% control efficiency for an Indigo Agglomerator-enhanced wet ESP (EW-ESP). No additional condensable $PM_{2.5}$ control would be provided by the Indigo ESP enhancement technology.

Membrane Wet Electrostatic Precipitator

Based on the description of this technology, some enhanced recovery of fine particulate and condensable parameters may be realized by deploying it at HGS. However, based on evaluation of the information available from Southern Environmental's web page,[32] performance data availability is limited.

Due to this information gap, it is conservatively estimated that control efficiencies for the MW-ESP are the same as a standard W-ESP. For the purpose of this analysis, the primary advantage of this technology is capital cost and annual cost savings due to efficiency gains in water handling.

Control Efficiency Summaries

Individual Control Efficiencies

Table 0-1 summarizes the estimated control efficiencies described in the preceding sections.

Table 0-1: Summary of Estimated Filterable and Condensable $PM_{2.5}$ Control Efficiencies for Individual Technologies

Technology	Estimated Control Efficiency		
	Filterable	Condensable	Total[33]
Wet Electrostatic Precipitator (WESP)	96.0%	90%	95.7%
Fabric Filter Baghouse (FFB) with specialty filters	99.5%	30%	96.2%
Fabric Filter Baghouse (FFB) membrane	99.9%	0%	95.1%
Electrostatic Fabric Filter Baghouse (ESFFB)	99.6%	0%	94.9%
Wet FGD	80%	80%	80.0%
Dry FGD	0%	75%	3.57%
Enhanced Dry FGD	0%	79%	3.76%
Dry ESP	97.7%	0%	93.0%
Enhanced Dry ESP	99.5%	0%	94.8%
Enhanced Wet ESP	99.2%	90%	98.8%
Membrane Wet ESP	96.0%	90%	95.7%
Cyclonic Separators	70%	0%	66.7%

31 "Indigo Particle Agglomerators Reduce Mass and Visible Emissions on Coal Fired Boilers in the US," Robert Crynack, Rodney Truce, Wallis Harrison, *et al.*, June 2006, see http://www.indigotechnologies.com.au/site_ch/documents/M-TP14-ICESPX-IndigoAgglomeratorsintheUS.pdf

32 http://www.southernenvironmental.com/

33 This is based on uncontrolled emissions of 18,400 tpy filterable $PM_{2.5}$ emissions and 920 tpy condensable $PM_{2.5}$ emissions as discussed in Section 1.2.

Aggregate Control Efficiencies

Effective filterable and condensable control efficiencies for systems with multiple equipment in series were calculated and are listed in Table 0-2.

Table 0-2: Estimated Control Efficiencies for Analyzed Control Options

Control Option #	Estimated Control Efficiency (%)		Control Option #	Estimated Control Efficiency (%)	
	Filterable $PM_{2.5}$	Condensable $PM_{2.5}$		Filterable $PM_{2.5}$	Condensable $PM_{2.5}$
1	99.5%	0%	54	99.996%	98.25%
2	99.9%	0%	55	99.9968%	97.75%
3	99.6%	0%	56	99.9968%	98.53%
4	97.7%	0%	57	99.9975%	85.3%
5	96.0%	90%	58	99.998%	81.1%
6	99.5%	0%	59	99.996%	98.53%
7	99.2%	90%	60	99.9968%	98.11%
8	96.0%	90%	61	99.9995%	75%
9	99.5%	82.5%	62	99.9992%	97.5%
10	99.6%	77.5%	63	99.9995%	79%
11	99.6%	85.3%	64	99.9992%	97.9%
12	99.9%	75%	65	99.98%	97.5%
13	97.7%	75%	66	99.98%	97.9%
14	96.0%	97.5%	67	99.9999885%	82.5%
15	99.2%	98%	68	99.99998%	98.25%
16	99.5%	85.3%	69	99.999984%	97.75%
17	99.6%	81.1%	70	99.9999885%	85.3%
18	99.9%	79.0%	71	99.9999908%	81.1%
19	97.7%	79.0%	72	99.99998%	98.53%
20	96.0%	97.9%	73	99.999984%	98.11%
21	99.5%	75.0%	74	99.9999975%	0%
22	99.2%	97.5%	75	99.72%	0%
23	99.84%	98.0%	76	99.999996%	90%
24	99.2%	98.0%	77	99.99954%	98.25%
25	99.5%	79.0%	78	99.999632%	97.75%
26	99.2%	97.9%	79	99.99954%	98.53%
27	99.9995%	82.5%	80	99.999632%	98.11%
28	99.9996%	77.5%	81	99.99998%	90%
29	99.9996%	85.3%	82	99.99992%	90%
30	99.9885%	82.5%	83	99.9999975%	82.5%
31	99.9908%	77.5%	84	99.999998%	77.5%
32	99.9908%	85.3%	85	99.999996%	98.25%
33	99.98%	98.25%	86	99.9999968%	97.75%
34	99.984%	97.75%	87	99.9999975%	85.3%
35	99.984%	98.53%	88	99.999998%	81.1%
36	99.9995%	85.3%	89	99.999996%	98.53%
37	99.9996%	81.1%	90	99.9999968%	98.11%
38	99.9885%	85.3%	91	99.9999%	98.25%
39	99.9908%	81.1%	92	99.99992%	97.75%
40	99.98%	98.53%	93	99.99998%	98.53%
41	99.984%	98.11%	94	99.99992%	98.11%

Control Option #	Estimated Control Efficiency (%)		Control Option #	Estimated Control Efficiency (%)	
	Filterable $PM_{2.5}$	Condensable $PM_{2.5}$		Filterable $PM_{2.5}$	Condensable $PM_{2.5}$
42	99.9975%	0.0%	95	99.99999954%	98.25%
43	99.996%	90.0%	96	99.999999632%	97.75%
44	99.9968%	90.0%	97	99.99999954%	98.53%
45	99.9977%	75.0%	98	99.999999632%	98.11%
46	99.996%	97.5%	99	99.9999999%	90%
47	99.9977%	79.0%	100	99.99999992%	90%
48	99.996%	97.9%	101	99.9999999%	98.25%
49	99.9995%	0.0%	102	99.99999992%	97.75%
50	99.9992%	90.0%	103	99.9999999%	98.11%
51	99.9975%	82.5%	104	99.9999999996%	98.425%
52	99.998%	77.5%	105	99.9999999996%	98.677%
53	99.998%	85.3%			

It should be emphasized that the control efficiencies shown in the table above are calculated based on estimates of filterable and condensable control efficiencies for individual component equipment. The precision of some of the individual control efficiency estimates is relatively low due to a lack of relevant data. Therefore, the degree of precision that is technically justifiable for calculated composite efficiencies does not provide any distinction between many of the alternative control systems. Table 0-3 illustrates that many of the control options are essentially identical in terms of $PM_{2.5}$ control. Significant figures for the efficiency estimates shown in Table 0-2 are expanded merely in an attempt to create some distinction between control efficiencies for the control alternatives. This facilitates the screening of alternatives. The fact that the distinctions are in many cases without basis will be accounted for near the end of the analysis process.

Table 0-3: Estimated Control Efficiencies for Analyzed Control Options Rounded to Three Significant Digits

Control Option #	Estimated Control Efficiency (%)		Control Option #	Estimated Control Efficiency (%)	
	Filterable $PM_{2.5}$	Condensable $PM_{2.5}$		Filterable $PM_{2.5}$	Condensable $PM_{2.5}$
1	99.5%	0.0%	54	99.9+%	98.3%
2	99.9%	0.0%	55	99.9+%	97.8%
3	99.6%	0.0%	56	99.9+%	98.5%
4	97.7%	0.0%	57	99.9+%	85.3%
5	96.0%	90.0%	58	99.9+%	81.1%
6	99.5%	0.0%	59	99.9+%	98.5%
7	99.2%	90.0%	60	99.9+%	98.1%
8	96.0%	90.0%	61	99.9+%	75.0%
9	99.5%	82.5%	62	99.9+%	97.5%
10	99.6%	77.5%	63	99.9+%	79.0%
11	99.6%	85.3%	64	99.9+%	97.9%
12	99.9%	75.0%	65	99.9+%	97.5%
13	97.7%	75.0%	66	99.9+%	97.9%
14	96.0%	97.5%	67	99.9+%	82.5%
15	99.2%	98.0%	68	99.9+%	98.3%
16	99.5%	85.3%	69	99.9+%	97.8%
17	99.6%	81.1%	70	99.9+%	85.3%
18	99.9%	79.0%	71	99.9+%	81.1%
19	97.7%	79.0%	72	99.9+%	98.5%

Control Option #	Estimated Control Efficiency (%)		Control Option #	Estimated Control Efficiency (%)	
	Filterable $PM_{2.5}$	Condensable $PM_{2.5}$		Filterable $PM_{2.5}$	Condensable $PM_{2.5}$
20	96.0%	97.9%	73	99.9+%	98.1%
21	99.5%	75.0%	74	99.9+%	0.0%
22	99.2%	97.5%	75	99.7%	0.0%
23	99.8%	98.0%	76	99.9+%	90.0%
24	99.2%	98.0%	77	99.9+%	98.3%
25	99.5%	79.0%	78	99.9+%	97.8%
26	99.2%	97.9%	79	99.9+%	98.5%
27	99.9+%	82.5%	80	99.9+%	98.1%
28	99.9+%	77.5%	81	99.9+%	90.0%
29	99.9+%	85.3%	82	99.9+%	90.0%
30	99.9+%	82.5%	83	99.9+%	82.5%
31	99.9+%	77.5%	84	99.9+%	77.5%
32	99.9+%	85.3%	85	99.9+%	98.3%
33	99.9+%	98.3%	86	99.9+%	97.8%
34	99.9+%	97.8%	87	99.9+%	85.3%
35	99.9+%	98.5%	88	99.9+%	81.1%
36	99.9+%	85.3%	89	99.9+%	98.5%
37	99.9+%	81.1%	90	99.9+%	98.1%
38	99.9+%	85.3%	91	99.9+%	98.3%
39	99.9+%	81.1%	92	99.9+%	97.8%
40	99.9+%	98.5%	93	99.9+%	98.5%
41	99.9+%	98.1%	94	99.9+%	98.1%
42	99.9+%	0.0%	95	99.9+%	98.3%
43	99.9+%	90.0%	96	99.9+%	97.8%
44	99.9+%	90.0%	97	99.9+%	98.5%
45	99.9+%	75.0%	98	99.9+%	98.1%
46	99.9+%	97.5%	99	99.9+%	90.0%
47	99.9+%	79.0%	100	99.9+%	90.0%
48	99.9+%	97.9%	101	99.9+%	98.3%
49	99.9+%	0.0%	102	99.9+%	97.8%
50	99.9+%	90.0%	103	99.9+%	98.1%
51	99.9+%	82.5%	104	99.9+%	98.4%
52	99.9+%	77.5%	105	99.9+%	98.7%
53	99.9+%	85.3%			

Control Efficiency Rankings

To rank control technologies and options, a total, or aggregate, effective $PM_{2.5}$ control efficiency was derived from the series of individual control efficiencies for both filterable and condensable emissions presented in Table 0-1. The following equation was used to calculate the overall control efficiency:

Aggregate $PM_{2.5}$ Control Efficiency =

$$\left\{1-\left\{\frac{[(18{,}400*(100\%-C1_{FIL}\%)*(100\%-C2_{FIL}\%)]+[920*(100\%-C1_{CON}\%)*(100\%-C2_{CON}\%)]}{(18{,}400+920)}\right\}\right\}*100$$

The following example demonstrates the calculation of an aggregate total $PM_{2.5}$ control efficiency for a dry FGD unit followed by IC-FFB.

Example System		Uncontrolled Emissions (tpy)	Control Efficiency 1	Controlled Emissions 1 (tpy)	Control Efficiency 2	Controlled Emissions 2 (tpy)	Overall Control Efficiency
Control #1	Filterable:	18,400	0.0%	18,400	99.5%	92	98.6%
Control #2	Condensable:	920	75.0%	230	30.0%	161	

$$\left\{1-\left\{\frac{[(18{,}400*(100\%-0\%)*(100\%-99.5\%)]+[920*(100\%-75\%)*(100\%-30\%)]}{(18{,}400+920)}\right\}\right\}*100=98.6\%$$

Finally, the control options and technologies are ranked in descending order based on the estimated aggregate control efficiency. Table 0-4 presents the results of ranking the remaining control technologies and options in descending order from most effective to least effective. For consistency, control options retain the identification numbers assigned to them in Step 1 (see Table 0-2). Table 0-4 also lists annualized costs associated with each alternative control system. See Appendix D for detailed cost descriptions.

Table 0-4: Ranked $PM_{2.5}$ Control Options

Control Option #	Rank	Technology Combination	Estimated Aggregate Control Efficiency for Analysis (%)		Annualized Cost ($)
			Expanded	Reduced	
105	1	EDFGD + ICFFB + MFFB + ESFFB + EDESP + WESP	99.9369999996190	99.9+	$66,783,506
97	2	EDFGD + ICFFB + MFFB + DESP + WESP	99.9299995619048	99.9+	$54,942,893
89	3	EDFGD + ICFFB + MFFB + EWESP	99.9299961904762	99.9+	$47,570,990
72	4	EDFGD + ICFFB + MFFB + WESP	99.9299809523809	99.9+	$46,296,990
93	5	EDFGD + ICFFB + EDESP + WESP	99.9299809523809	99.9+	$43,073,992
79	6	EDFGD + ICFFB + DESP + WESP	99.9295619047619	99.9+	$42,391,492
56	7	SDA FGD+ESFFB2+EWESP	99.9269523809524	99.9+	$36,841,567
59	8	EDFGD + ICFFB + EWESP	99.9261904761905	99.9+	$35,019,589
104	9	DFGD + ICFFB + MFFB + ESFFB + EDESP + WESP	99.9249999996190	99.9+	$65,770,048
101	10	DFGD + ICFFB + MFFB + EDESP + WESP	99.9166665714286	99.9+	$54,611,935
95	11	DFGD + ICFFB + MFFB + DESP + WESP	99.9166662285714	99.9+	$53,929,435
85	12	DFGD + ICFFB + MFFB + EWESP	99.9166628571429	99.9+	$46,557,532
68	13	DFGD + ICFFB + MFFB + WESP	99.9166476190476	99.9+	$45,283,532
91	14	DFGD + ICFFB + EDESP + WESP	99.9165714285714	99.9+	$42,060,534
77	15	DFGD + ICFFB + DESP + WESP	99.9162285714286	99.9+	$41,378,034
35	16	SDA FGD + ESFFB2 + WESP	99.9147619047619	99.9+	$35,567,567
54	17	DFGD + ICFFB + EWESP	99.9128571428571	99.9+	$34,006,131
40	18	EDFGD + ICFFB + WESP	99.9109523809524	99.9+	$33,745,589
103	19	EDFGD + ESFFB + MFFB + EDESP + WESP	99.9099999047619	99.9+	$53,907,028
98	20	EDFGD + ESFFB + MFFB + DESP + WESP	99.9099996495238	99.9+	$53,224,528
90	21	EDFGD + ESFFB + MFFB + EWESP	99.9099969523810	99.9+	$45,852,625
73	22	EDFGD + ESFFB + MFFB + WESP	99.9099847619048	99.9+	$44,578,625
94	23	EDFGD + ESFFB + EDESP + WESP	99.9099238095238	99.9+	$41,355,627
80	24	EDFGD + ESFFB + DESP + WESP	99.9096495238095	99.9+	$40,673,127
60	25	EDFGD + ESFFB + EWESP	99.9069523809524	99.9+	$33,301,224
64	26	EDFGD + MFFB + EWESP	99.8992380952381	99.9+	$34,694,513

Control Option #	Rank	Technology Combination	Estimated Aggregate Control Efficiency for Analysis (%)		Annualized Cost ($)
			Expanded	Reduced	
33	27	DFGD + ICFFB + WESP	99.8976190476191	99.9+	$32,732,131
48	28	EDFGD + MFFB + WESP	99.8961904761905	99.9+	$33,420,513
41	29	EDFGD + ESFFB + WESP	99.8947619047619	99.9+	$32,027,224
102	30	DFGD + ESFFB + MFFB + EDESP + WESP	99.8928570666667	99.9+	$52,893,571
96	31	DFGD + ESFFB + MFFB + DESP + WESP	99.8928567923809	99.9+	$52,211,070
86	32	DFGD + ESFFB + MFFB + EWESP	99.8928540952381	99.9+	$44,839,168
69	33	DFGD + ESFFB + MFFB + WESP	99.8928419047619	99.9+	$43,565,168
92	34	DFGD + ESFFB + EDESP + WESP	99.8927809523810	99.9+	$40,342,170
78	35	DFGD + ESFFB + DESP + WESP	99.8925066666667	99.9+	$39,659,669
55	36	DFGD + ESFFB + EWESP	99.8898095238095	99.9+	$32,287,767
66	37	EDFGD + EDESP + WESP	99.8809523809524	99.9+	$30,197,515
62	38	DFGD + MFFB + EWESP	99.8801904761905	99.9+	$33,681,055
34	39	DFGD + ESFFB + WESP	99.8776190476190	99.9+	$31,013,767
46	40	DFGD + MFFB + WESP	99.8771428571429	99.9+	$32,407,055
65	41	DFGD + EDESP + WESP	99.8619047619048	99.9+	$29,184,057
23	42	WFGD + EWESP	99.7523809523809	99.8	$64,057,958
100	43	ESFFB + MFFB + EDESP + WESP	99.5238094476190	99.5	$49,823,886
99	44	ICFFB + MFFB + EDESP + WESP	99.5238094285714	99.5	$51,542,250
76	45	ICFFB + MFFB + EWESP	99.5238057142857	99.5	$43,487,847
81	46	ICFFB + EDESP + WESP	99.5237904761905	99.5	$38,990,849
82	47	ESFFB + EDESP + WESP	99.5237333333333	99.5	$37,272,485
50	48	MFFB + EWESP	99.5230476190476	99.5	$30,611,370
44	49	ESFFB + EWESP	99.5207619047619	99.5	$29,218,082
43	50	ICFFB + EWESP	99.5200000000000	99.5	$30,936,446
87	51	EDFGD + EDESP + ICFFB + MFFB	99.2999976190476	99.3	$38,839,424
70	52	EDFGD + DESP + ICFFB + MFFB	99.2999890476190	99.3	$38,156,924
29	53	SDA FGD+ESFFB2+MFFB	99.2996190476190	99.3	$31,332,999
36	54	EDFGD + ICFFB + MFFB	99.2995238095238	99.3	$29,511,021
53	55	SDA FGD + ESFFB2 + EDESP	99.2980952380952	99.3	$28,110,001
57	56	EDFGD + ICFFB + EDESP	99.2976190476190	99.3	$26,288,023
32	57	SDAFGD+ESFFB2+DESP	99.2912380952381	99.3	$27,427,501
38	58	EDFGD + ICFFB + DESP	99.2890476190476	99.3	$25,605,523
83	59	DFGD + EDESP + ICFFB + MFFB	99.1666642857143	99.2	$37,825,967
67	60	DFGD + DESP + ICFFB + MFFB	99.1666557142857	99.2	$37,143,466
27	61	DFGD + ICFFB + MFFB	99.1661904761905	99.2	$28,497,564
51	62	DFGD + ICFFB + EDESP	99.1642857142857	99.2	$25,274,566
30	63	DFGD + ICFFB + DESP	99.1557142857143	99.2	$24,592,065
15	64	WFGD + WESP	99.1428571428571	99.1	$62,783,958
24	65	WFGD + MWESP	99.1428571428571	99.1	$59,084,189
26	66	EDFGD + EWESP	99.1380952380952	99.1	$22,143,112
22	67	DFGD + EWESP	99.1190476190476	99.1	$21,129,654
88	68	EDFGD + EDESP + ESFFB + MFFB	99.0999980952381	99.1	$37,121,060
71	69	EDFGD + DESP + ESFFB + MFFB	99.0999912380952	99.1	$36,438,559
37	70	EDFGD + ESFFB + MFFB	99.0996190476190	99.1	$27,792,657

Control Option #	Rank	Technology Combination	Estimated Aggregate Control Efficiency for Analysis (%)		Annualized Cost ($)
			Expanded	Reduced	
58	71	EDFGD + ESFFB + EDESP	99.0980952380952	99.1	$24,569,659
39	72	EDFGD + ESFFB + DESP	99.0912380952381	99.1	$23,887,158
63	73	EDFGD + EDESP + MFFB	98.9995238095238	99.0	$25,962,947
47	74	EDFGD + DESP + MFFB	98.9978095238095	99.0	$25,280,446
84	75	DFGD + EDESP + ESFFB + MFFB	98.9285695238095	98.9	$36,107,602
28	76	DFGD + ESFFB + MFFB	98.9281904761905	98.9	$26,779,199
52	77	DFGD + ESFFB + EDESP	98.9266666666667	98.9	$23,556,201
31	78	DFGD + ESFFB + DESP	98.9198095238095	98.9	$22,873,701
11	79	SDA FGD + ESFFB2	98.9190476190476	98.9	$18,781,598
18	80	EDFGD + MFFB	98.9047619047619	98.9	$16,634,544
16	81	EDFGD + ICFFB	98.8238095238095	98.8	$16,959,620
61	82	DFGD + EDESP + MFFB	98.8090476190476	98.8	$24,949,489
45	83	DFGD + DESP + MFFB	98.8073333333333	98.8	$24,266,989
7	84	EWESP	98.7619047619048	98.8	$18,059,969
17	85	EDFGD + ESFFB	98.7190476190476	98.7	$15,241,256
12	86	DFGD + MFFB	98.7142857142857	98.7	$15,621,086
9	87	DFGD + ICFFB	98.6904761904762	98.7	$15,946,163
10	88	DFGD + ESFFB	98.5476190476191	98.5	$14,227,798
25	89	EDFGD + EDESP	98.5238095238095	98.5	$13,411,546
21	90	DFGD + EDESP	98.3333333333333	98.3	$12,398,088
19	91	EDFGD + DESP	96.8095238095238	96.8	$12,729,045
13	92	DFGD + DESP	96.6190476190476	96.6	$11,715,588
20	93	EDFGD + WESP	96.0904761904762	96.1	$20,869,112
14	94	DFGD + WESP	96.0714285714286	96.1	$19,855,654
5	95	WESP	95.7142857142857	95.7	$16,785,969
8	96	MWESP	95.7142857142857	95.7	$13,086,200
74	97	EDESP + ICFFB + MFFB	95.2380928571429	95.2	$34,756,281
49	98	EDESP + MFFB	95.2376190476190	95.2	$21,879,804
42	99	EDESP + ICFFB	95.2357142857143	95.2	$22,204,880
2	100	MFFB	95.1428571428571	95.1	$12,551,401
75	101	EDESP + ESFFB + MFFB	94.9714285714286	95.0	$33,037,917
3	102	ESFFB	94.8571428571429	94.9	$11,158,113
1	103	ICFFB	94.7619047619048	94.8	$12,876,477
6	104	EDESP	94.7619047619048	94.8	$9,328,403
4	105	DESP	93.0476190476191	93.0	$8,645,903

ED-FGD = enhanced dry FGD; D-FGD = dry FGD; IC-FFB = FFB with intrinsically coated filters; M-FFB = FFB with membrane filters; ES-FFB = electrostatic fabric filter; WESP = wet ESP; EWESP = enhanced wet ESP; DESP = dry ESP; EDESP = enhanced dry ESP; W-FGD = wet FGD; CS = centrifugal separator

As before, it should be emphasized that the values shown in the table above are calculated based on estimated inputs with widely varying degrees of precision, up to plus or minus 20 to 30 percent. Expanded significant figures are shown here for the sole purpose of ranking options for which no practical control efficiency distinction can be made. A control efficiency column is included in the table to illustrate that most of the control alternatives actually provide an equivalent level of $PM_{2.5}$

control as far as can be justifiably estimated. These artificial distinctions will be addressed later in the BACT analysis.

Step 4 - Evaluate $PM_{2.5}$ Control Technologies
Screening

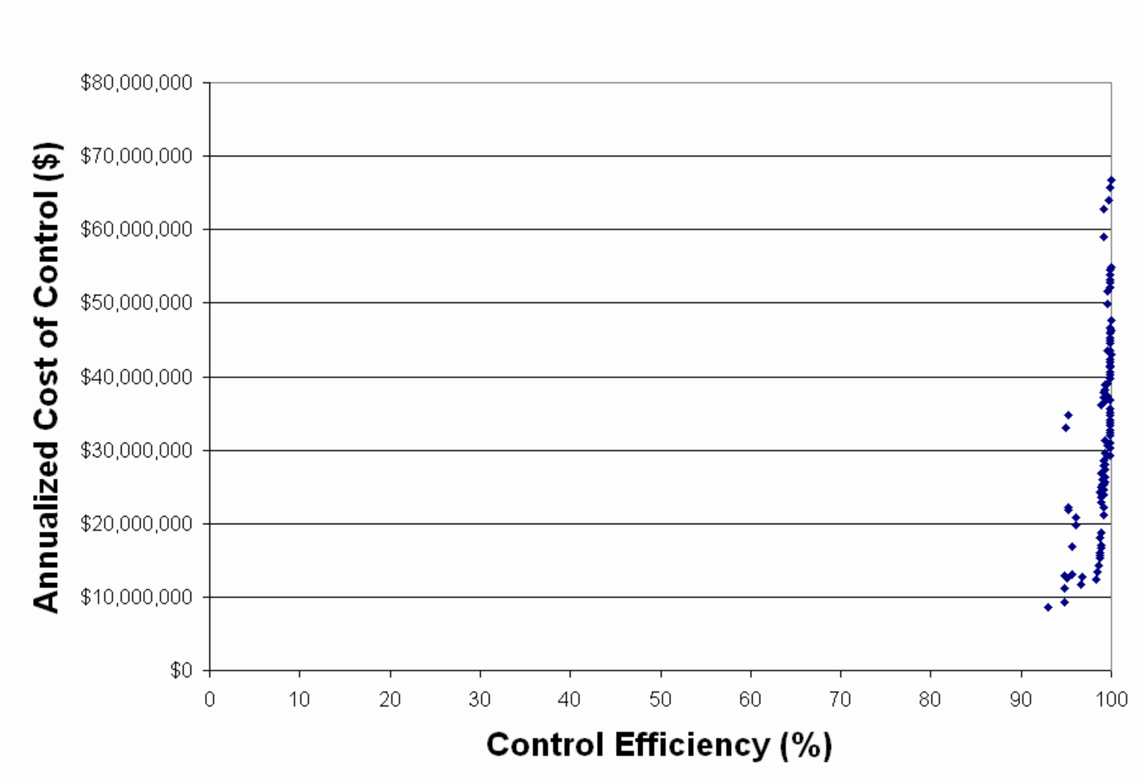
According to the NSR Manual, the next step in the BACT analysis is to begin evaluating – and eliminating as appropriate – technically feasible alternatives starting with the most effective alternative. The evaluations should specifically describe related environmental, energy, and economic impacts. If the most effective alternative is determined to be inappropriate as BACT for the proposed source, the second-most effective alternative is then analyzed for the same impacts. This continues until a control alternative is determined to be appropriate as BACT for the proposed source.

It was noted previously that EPA's intention is not to require evaluation of "unnecessarily large numbers of control alternatives" when performing a BACT analysis. The NSR Manual states: "Consequently, judgment should be used in deciding what alternatives will be evaluated in detail in the impacts analysis (Step 4) of the top-down procedure…"[34] One of the screening methods the manual suggests is to identify technologies that result in essentially equivalent control efficiencies and evaluate only the least-cost technologies among them.

Figure 1 graphically illustrates the fact that all of the original 105 alternative control technologies identified for consideration potentially provide very similar $PM_{2.5}$ control efficiencies. Control efficiencies for the least and most effective alternatives are separated by only seven percent. Of the 105 alternatives, 41 are estimated to control $PM_{2.5}$ with 99.9 percent or greater efficiency. The graph also shows that, while control efficiency varies little among the group of alternatives, the cost of control varies greatly, from \$29.2 million to \$66.8 million in annual costs and \$126 million to \$238 million in capital costs.

[34] NSR Manual, page B.20.

Figure 1: Control Cost Versus Control Efficiency



Another suggested method for identifying meaningful alternatives for detailed evaluation is described on pages B.41 through B.44 of the manual. This graphical method plots alternatives according to their annualized costs and pollutant reduction potentials. The graphed data suggest a set of "dominant" alternatives that are generally the most cost effective systems. These dominant alternatives form a curve referred to as the "envelope of least-cost alternatives." The technologies that lie on or near the least-cost envelope are dominant in that they generally are less expensive than other systems with similar performance. Note that this process is a screening technique meant to efficiently winnow redundant systems and limit the number of alternatives requiring detailed analysis in Step 4. The technique considers only pollution control costs and ignores energy and collateral environmental impacts. Further, the requirement to identify and employ BACT does not preclude the selection of a pollution control system that is as effective but more expensive than an alternate system. Accordingly, the least-cost envelope screening methodology is a tool to be used with judgment in concert with an awareness of other pertinent factors.

The following paragraphs describe the process followed to screen alternative technologies based on a dominant technologies methodology for this analysis. Figure 2 contains the same data as Figure 1 except they are scaled to better distinguish the alternatives listed in Table 0-2. This graph suggests two distinct groupings of control alternatives as indicated by the red and green ovals. Those technologies circled in red provide significantly lower removal effectiveness for approximately equivalent costs relative to the systems circled in green. Thus, this inferior group of technologies is screened out and does not merit further detailed analysis.

Figure 2: Comprehensive Cost vs. Performance Graph of Alternative Control Technologies

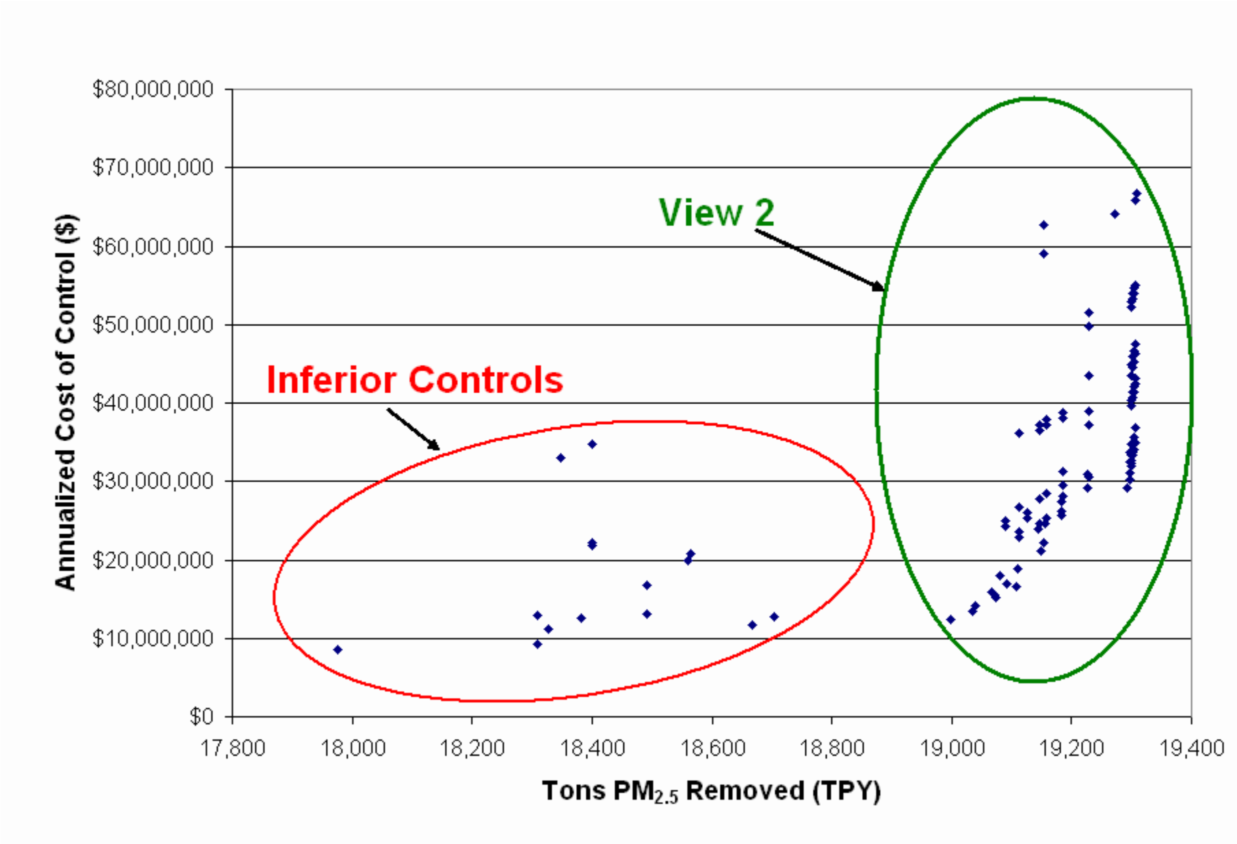


Figure 3 gives a closer view of the remaining alternatives after the inferior alternatives shown in Figure 2 have been screened out. A line representing the least cost envelope that defines the dominant controls for this analysis has been drawn as described by the NSR manual (page B.41). The systems on or near this line dominate, or are more cost-effective relative to the systems farther from the line, which have been circled in red. Thus, the inferior systems are removed from the analysis.

The blue circle in Figure 3 is a cluster of similar performing systems with similar costs. The NSR manual recommends that if a group of control alternatives would result in essentially equivalent emissions, taking into account uncertainties typically inherent in the underlying performance estimates, the least costly system may be chosen for further detailed analysis (NSR manual, page B.20). System #65 is substantially similar in performance to the other systems on the graph and incurs the lowest cost. Consequently, it was chosen for further detailed analysis and is included as a dominant control option on the least cost envelope shown in Figure 4.

Figure 3: Alternative Control Technologies

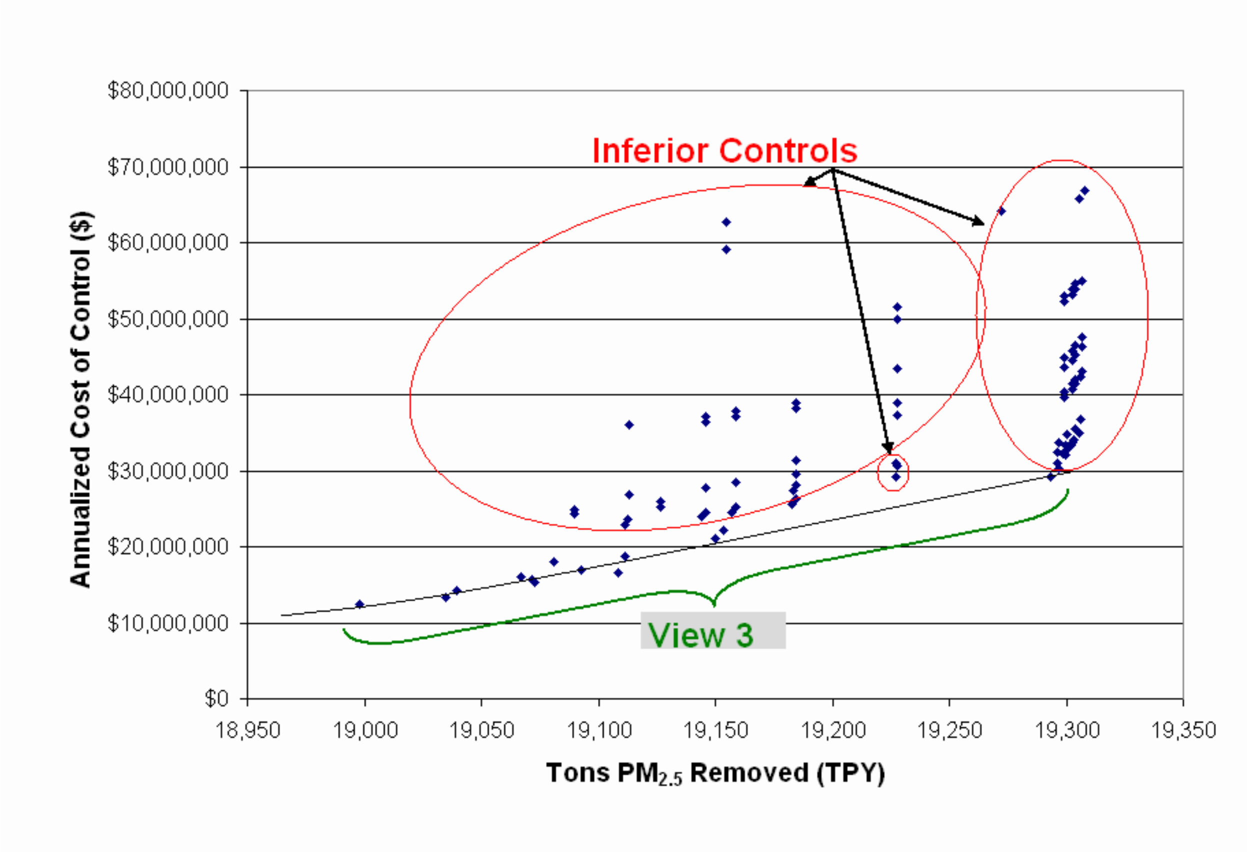


Figure 4 shows the remaining fourteen alternatives that are considered dominant in this analysis along with the least cost envelope curve.

Figure 4: Least-Cost Envelope, View 1

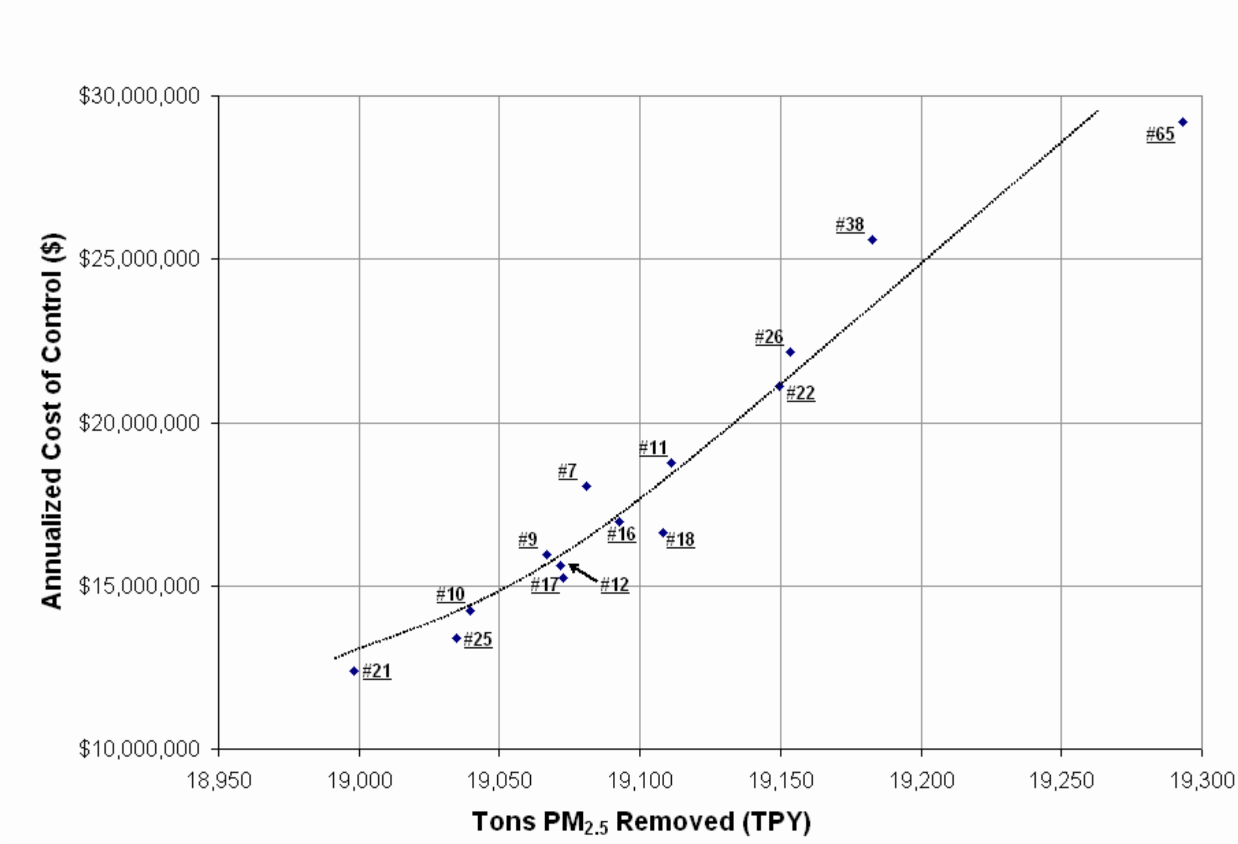
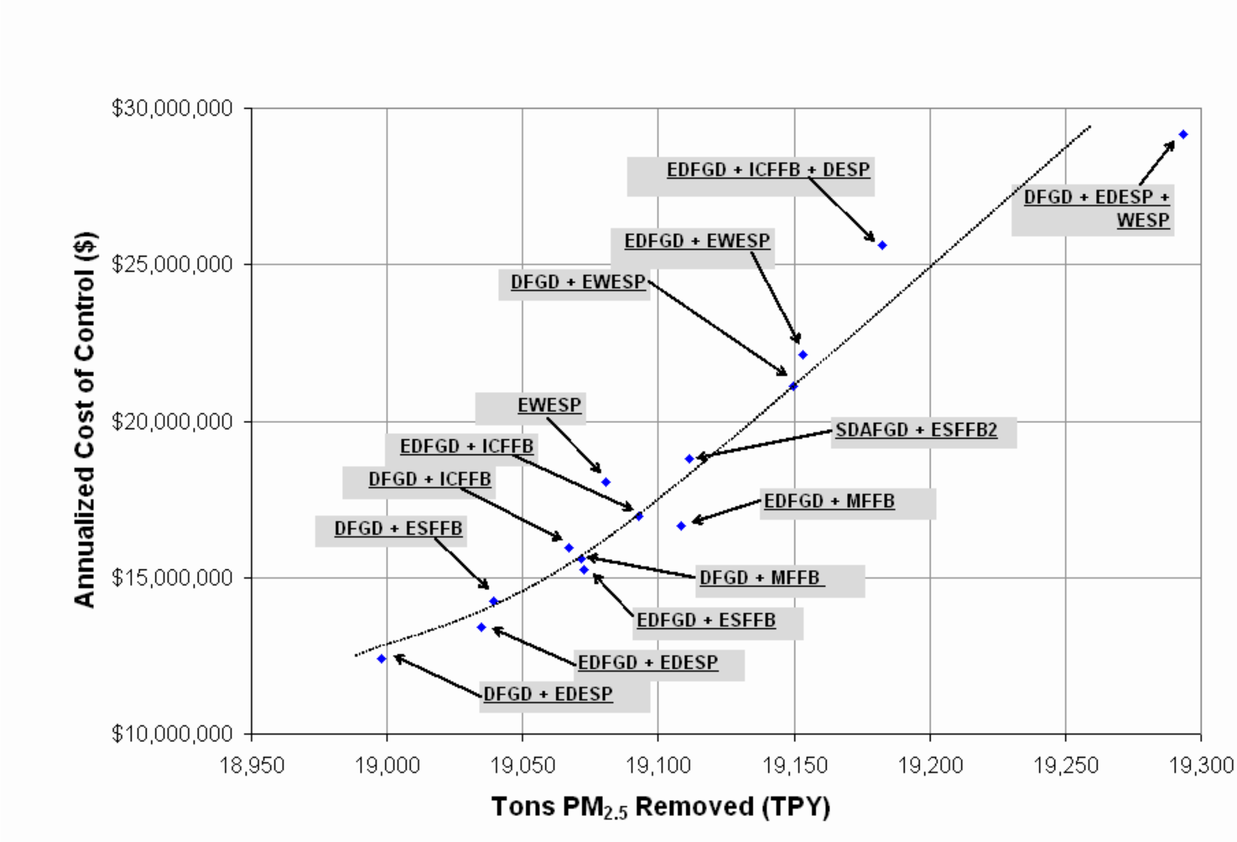


Figure 5 is identical to Figure 4, but the system numbers have been replaced with system descriptions for improved clarity. The systems shown in Figure 5 are the final dominant controls that have made it through the screening process. The BACT process will now analyze in detail the fourteen remaining alternatives for energy, environmental and economic impacts.

Figure 5: Least-Cost Envelope, View 2



Evaluate Remaining Dominant Control Systems

The fourteen remaining alternatives are listed in Table 5-1 below. The remainder of this section evaluates the environmental, energy and economic impacts of the remaining technologies, starting with the most effective remaining alternative, #65. As stated in the NSR manual, Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top alternative in the listing is BACT. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the result is proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the next alternative must be analyzed as the next "top" alternative. The top remaining alternative is then selected in Step 5 as BACT for HGS.

Table 0-1: Ranked Alternative $PM_{2.5}$ Control Systems Selected for Detailed Evaluation

System #	Technology	Estimated Total Control Efficiency for Analysis	Annual Controlled Emissions (tons/yr)
65	DFGD + EDESP + WESP	99.86%	19,293
38	EDFGD + ICFFB + DESP	99.29%	19,183
26	EDFDG + EWESP	99.14%	19,154
22	DFGD + EWESP	99.12%	19,150
11	SDAFGD + ESFFB	98.92%	19,111
18	EDFGD + MFFB	98.90%	19,108
16	EDFGD + ICFFB	98.82%	19,093
7	EWESP	98.76%	19,081
17	EDFGD + ESFFB	98.72%	19,073
12	DFGD + MFFB	98.71%	19,072
9	DFGD + ICFFB	98.69%	19,067
10	DFGD + ESFFB	98.55%	19,039
25	EDFGD + EDESP	98.52%	19,035
21	DFGD + EDESP	98.33%	18,998

ESFFB = Electrostatic Fabric Filter Baghouse; ED-FGD = enhanced dry FGD; D-FGD = dry FGD; IC-FFB = FFB with intrinsically coated filters; M-FFB = FFB with membrane filters; WESP = wet ESP; DESP = dry ESP; EDESP = enhanced dry ESP

Economic impacts analyses summarized below were conducted following estimating guidelines published in the EPA Air Pollution Control Cost Manual (EPA/452/B-02-001, Sixth Edition, January 2002). They are based on equipment costs estimated with accuracies on the order of ±20 to 30 percent as directed by the NSR Manual (page B.44).

A summary of the energy, environmental and economic impacts of the analyzed alternatives is contained in Table 0-1, Table 0-2, and Table 6-3 at the end of Section 6.0.

System #65 – Dry FGD + Enhanced Dry ESP + Wet ESP

Environmental Impacts

The enhanced dry FGD will inject hydrated lime into the exhaust stream. This will add approximately 20 tons per day to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

The wet ESP will require that water be provided, treated, and discharged. SME has a contract with the City of Great Falls to provide water that is required for potable uses, cooling and general plant operation. For the City to provide water to HGS from Morony Pool, they had to request and secure a point of diversion change for an existing water reservation from the Montana Department of Natural Resources. That process took several years, including a challenge to the point of diversion change from PPL-Montana that had to be worked through.

It is estimated that the existing contracted water supply rate exceeds the HGS facility's projected total water requirements by approximately 50 gal/min. The boiler designer estimates a wet ESP would require approximately 250 gal/min of water. This amount, when added to current plant operational water requirements, exceeds SME's contracted water supply limit by approximately 200 gal/min. From conversations with the City, additional water would potentially be available; however, a revised contract and similar point of diversion change process to that described above would be needed to make it available to HGS. That process would, at a minimum, require additional time and result in additional uncertainty and potential challenges to the project.

The availability of groundwater to support this additional need is also questionable. Based on an evaluation of hydrogeology in the area surrounding HGS for the ash landfill solid waste license, only the Madison Limestone and Kootenai formations could potentially produce water to be used for HGS. Based on a nearby well, the Madison formation could potentially produce quantities of water in the above range, although the average yield of area Madison wells is less than the above demand. Further, deep wells would have to be drilled and evaluated and water rights procured. Wells into the Kootenai formation in the area produce water at a rate between 3 and 200 gal/min., with an average yield of 32 gal/min. Based on the hydrogeology report, the Kootenai formation would likely be eliminated as a reliable source of water of this quantity. Water quality would also be a concern for use of groundwater to supplement Missouri River water. A redesign of the water treatment system would potentially be required with additional expense (undetermined at this point).

In addition to the concerns about procuring additional water, the wet ESP system would generate new waste streams in the form of water requiring treatment and discharge, and sludge requiring landfill disposal. This results in two issues for SME: wastewater discharge permitting and solid waste licensing for HGS.

Costs for treating the wastewater from the wet ESP system have been estimated and included in the BACT cost analysis for that control equipment. However, the impact of the wet ESP wastewater on the current plan to deliver HGS wastewater to the City of Great Falls under the auspices of an industrial discharge permitting arrangement has not been evaluated. At a minimum, wet ESP wastewater constituents will need to be evaluated and included in a revised application for an Industrial User Discharge permit from the City of Great Falls.

The current solid waste disposal system at HGS is a dry system and has received a solid waste license from MDEQ based on this design. The introduction of a wet waste stream, at a minimum, will require SME to re-visit the solid waste licensing process. It may also require re-design of the ash landfill, including the proposed liner for the landfill, with resultant undefined significant costs to the project.

The NSR Manual indicates that impacts of control alternatives to water and land resources be considered in the BACT decision-making process. Because the application of a wet air pollution control technology (e.g., wet ESP) fundamentally shifts the pollution control from entirely dry (current design) to one with a wet control device, a significant shift in environmental impact occurs. It is difficult to assess the adverse impacts to the project that would result from permitting these changes without actually proceeding with permit revisions, but they will be significant. Given local and nationwide concerns about water quality impacts from coal-fired electric generating units, trading one environmental impact for another (i.e., removing a small amount of additional air pollution while creating more impacts to land and water) is a trade-off that should be carefully considered in this analysis.

Another environmental impact of this system is the reduced level of SO_2 control it exhibits versus the currently permitted control system. On page B.46 of the NSR manual, it explicitly states, "the environmental impacts portion of the BACT analysis concentrates on the impacts other than impacts on air quality standards due to emissions of the regulated pollutant in question." SME therefore believes the impacts on air pollutants other than $PM_{2.5}$ should be examined. The manual further states on page B.49, under *Other Environmental Impacts*, **"One environmental impact that could be examined is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increase in emissions of pollutants other than those the technology was designed to control."**

The absence of a filter cake on an FFB, indeed the lack of an FFB altogether, will lead to reduced SO_2 control effectiveness because the filter cake in the FFB is estimated to provide up to an additional 30% post-CFB boiler SO_2 emissions control. This reduced SO_2 control efficiency will endanger compliance with the existing SO_2 BACT-derived limits. This combination of control technologies will result in SME losing its guarantees for emissions limits in the existing permit. Although this system is more efficient at filtering direct $PM_{2.5}$ than the other dominant control systems, there is a significant tradeoff in lost efficiency for SO_2. If we assume a worst case loss of 20-30% of SO_2 control, emissions would potentially increase by thousands of tons per year.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of System #65 would require 2.06 MW of power (approximate). This reduces overall efficiency of the boiler and, by doing so, offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

The final factor that must be taken into account when determining BACT is "economic impacts and other costs."[35] The purpose of evaluating costs is to determine whether implementation of a particular control technology at one facility would result in costs, on a per-ton basis, in excess of BACT-related costs experienced at other similar facilities for the same pollutant. The two types of cost values prescribed for evaluation in the NSR Manual are average cost-effectiveness and incremental cost-effectiveness. Both describe the cost of removing one ton of pollutant (i.e., \$/ton). Average cost-effectiveness is calculated by dividing the total annualized cost of an alternative technology by the number of tons of pollutant that would be removed in a year. In this case, the baseline is the estimated total $PM_{2.5}$ emissions that would result from the proposed limestone CFB boiler with no additional controls.

Incremental cost-effectiveness describes the marginal cost of increased emissions control relative to the next most effective alternative under consideration. It is calculated by dividing the incremental cost by the incremental amount of pollutant that would be removed. Figure 6 shows this concept graphically for the alternative systems that will be evaluated here.

While the NSR Manual does not prescribe other cost impact indicators, it is instructive in this case to consider the cost impact of various pollution control alternatives relative to the projected price of the power that will be produced by HGS. This evaluation provides a context useful for determining whether a control alternative would result in unreasonable adverse economic impacts relative to those imposed on other electric utilities by BACT requirements.

Listed below are relevant costs and economic impacts related to **System #65 - DFGD + EDESP + WESP**.

Total estimated capital cost	\$126 million
Total annualized cost	\$29.2 million/yr
Annual $PM_{2.5}$ emissions reduced	19,293 tons/yr
Annual $PM_{2.5}$ emissions remaining	27 tons/yr
Average cost-effectiveness	\$1,513/ton
Incremental cost-effectiveness (relative to next most effective alternative)	\$32,333/ton
Incremental cost-effectiveness vs. chosen BACT alternative	\$60,952/ton
Pollution control cost per MW-hr	\$14.03/MW-hr
Pollution control cost as percentage of projected power price (\$70 per MW-hr)	20.04%

[35] See the definition of BACT at ARM 17.8.801(6).

It should also be noted that if SME were required to obtain additional water – either from the City of Great Falls or from an aquifer – the resulting schedule delay, administrative effort, and permitting requirements would add substantial cost that is not included in the above estimates.

Conclusion

SME concludes that System #65 – consisting of a Dry FGD, followed by an Enhanced Dry ESP and a Wet ESP – is not BACT. This conclusion is based on the above evaluations of adverse environmental and economic impacts. The primary factors are the production of a wet waste stream that would require extensive processing and problematic disposal, additional water volumes that may not be attainable and that would significantly impact project schedule and costs, the possible reduction of SO_2 control efficiency and direct economic impacts that substantially exceed those experienced by other utilities as a result of employing BACT.

By not incorporating an FFB into the design of this system, its implementation would trade a small increase in filterable particulate control for a similar decrease in condensable particulate control and a large decrease in SO_2 control. Since SO_2 is a $PM_{2.5}$ precursor, $PM_{2.5}$ emissions are actually expected to increase substantially. SME believes risking a significant increase in SO_2, to gain a few tons/year of direct $PM_{2.5}$ reductions with this system compared to the next system is not appropriate.

The economic impact of System #65 can be seen in the capital and annualized costs of pollution control (for this alternative) of $126 million and $29.2 million, respectively. These costs approximately double the investment and annual costs for $PM_{2.5}$ control when compared to the estimated costs for the currently permitted BACT particulate control system. To relate control costs to the projected price of electricity produced, this system would add a total of $14.03 per MW-hr. For reference, the currently permitted system would raise the cost of power by $7.66 per MW-hr. Thus, this system raises the cost of power by $6.37/MW-hr, or adds $13.2 million per year over the current system to remove an additional 1.17% of the total uncontrolled $PM_{2.5}$. Further, $32,333 to remove each additional ton of $PM_{2.5}$ that would not be removed by the next most effective alternative is an unreasonable incremental cost. Finally, the average cost-effectiveness of this alternative is also quite high, both considering the number of tons of pollutants removed across this multiple technology control system, and in relation to industry norms, as described below.

RTP Environmental Associates, a large environmental consulting firm that has extensive experience with air quality permitting throughout the country, has noted that BACT decisions applied to large industrial sources such as utilities are often influenced by average cost-effectiveness values in the range of a hundred dollars per ton removed, with control alternatives above those cost levels rejected as exceeding cost norms.

The following two recent agency BACT determination examples support this claim.

1. In a PSD permit issued by the State of Wyoming in 2006 for a new pulverized coal-fired electric utility boiler at Black Hills Power & Light's WYGEN3 project, Wyoming indicated that an incremental cost-effectiveness of $14,609/ton, comparing a baghouse with fiberglass or polyphenylene sulfide (PPS) filter bags, listed as capable of achieving 0.012 lb/MMBtu, to a baghouse with specialty filter bags such as Teflon®, listed as capable of achieving 0.011 to 0.010 lb/MmBtu, for PM/PM_{10} control, was excessive for BACT. The average cost-effectiveness of the selected BACT option, a baghouse with

fiberglass or polyphenylene sulfide filter bags, was $130/ton; the average cost-effectiveness of the eliminated option, a baghouse with specialty filter bags, was $134/ton. (Ref: Wyoming's Permit Application Analysis for the WYGEN3 project, NSR-AP-3934, October 9, 2006.)

2. In a PSD permit issued by the State of Utah in 2004 for a new pulverized coal-fired electric utility boiler at Intermountain Power's Unit 3, Utah concluded that an incremental cost-effectiveness of $14,000/ton to $16,350/ton, comparing different types of baghouse fabric filter bags (Ryton-type bags versus specialty coated bags) for PM/PM_{10} control, was excessive for BACT. The average cost-effectiveness of the selected BACT option for PM_{10} control (a baghouse with Ryton-type bags) was $31/ton. (Ref: Utah's Modified Source Plan Review for IPP3 project, March 22, 2004, available online at http://www.airquality. utah.gov/Permits/PmtPowerPlants.htm.)

	Facility	State	Unit Type	Pollutant	Control Technology Rejected	Cost-Effectiveness, $ per ton controlled	
						Average	Incremental
1	**Intermountain Power 3**	**UT**	**PC**	**PM / PM_{10}**	**Teflon Bags**	**$31**	**$14,000**
2	**Black Hills Power & Light – WYGEN3**	**WY**	**PC**	**PM / PM_{10}**	**Teflon Bags**	**$134**	**$14,609**

Further data on cost-effectiveness was drawn from the EPA RBLC data. SME surveyed the database for particulate matter (PM) and PM_{10} cost-effectiveness entries. Recognizing these entries are for different size range particulate matter, they are nonetheless a data set to relate to. The RBLC search found PM_{10} cost-effectiveness ranging from $31/ton to $252/ton; PM cost-effectiveness values ranged from $6/ton to $252/ton. See Appendix C for RBLC search results.

The next most effective control alternative listed in Table 5-1 will be evaluated below to determine whether it is BACT for this application.

System #38 – Enhanced Dry FGD + FFB with IC Filters + Dry Electrostatic Precipitator

Environmental Impacts

The enhanced dry FGD will inject hydrated lime into the exhaust stream. This will add approximately 20 tons per day to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of System #38 would require 2.61 MW of power (approximate). This system has the highest power load of any of the 14 systems listed in Table 5-1. This load reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are relevant costs and economic impacts related to System #38 – EDFGD + ICFFB + DESP.

Total estimated capital cost	$92 million
Total annualized cost	$25.6 million/yr
Annual $PM_{2.5}$ emissions reduced	19,183 tons/yr
Annual $PM_{2.5}$ emissions remaining	137 tons/yr
Average cost-effectiveness	$1,335/ton
Incremental cost-effectiveness (relative to next most effective alternative)	$118,722/ton
Incremental cost-effectiveness vs. chosen BACT alternative	$96,190/ton
Pollution control cost per MW-hr	$12.31/MW-hr
Pollution control cost as percentage of projected power price ($70 per MW-hr)	17.58%

Conclusion

SME concludes that System #38 – consisting of Enhanced Dry FGD, followed by FFB with IC Filters and Dry ESP – is not "achievable" in the present case and is therefore not BACT. This conclusion is based on the above evaluations of adverse environmental, energy and economic impacts. The primary factor is the economic impact of this system.
The economic impact of System #38 can be seen in the capital and annualized costs of pollution control (for this alternative) of $92 million and $25.6 million, respectively. When these pollution control costs are related to the projected price of electricity, an additional $12.31/MW-hr would be required, raising the cost of power by 17.58%. Further, $118,772 to remove each additional ton of $PM_{2.5}$ that would not be removed by the next most effective alternative is an unreasonable incremental cost. Finally, the average cost-effectiveness of this alternative is also quite high, both considering the number of tons of pollutants removed across this multiple technology control system, and in relation to industry norms (see Item 1 above).

The next most effective control alternative listed in Table 5-1 will be evaluated below to determine whether it is BACT for this application.

System #26 – Enhanced Dry FGD + Enhanced Wet Electrostatic Precipitator

Environmental Impacts

The enhanced dry FGD will inject hydrated lime into the exhaust stream. This will add approximately 20 tons per day to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

Wet ESP will require that water be provided, treated, and discharged. SME has a contract with the City of Great Falls to provide water that is required for potable uses, cooling and general plant operation. For the City to provide water to HGS from Morony Pool, they had to request and secure a point of diversion change for an existing water reservation from the Montana Department of Natural Resources. That process took several years, including a challenge to the point of diversion change from PPL-Montana that had to be worked through.

It is estimated that the existing contracted water supply rate exceeds the HGS facility's projected total water requirements by approximately 50 gal/min. The boiler designer estimates a wet ESP would require approximately 250 gal/min of water. This amount, when added to current plant operational water requirements, exceeds SME's contracted water supply limit by approximately 200 gal/min. From conversations with the City, additional water would potentially be available; however, a revised contract and similar point of diversion change process to that described above would be needed to make it available to HGS. That process would, at a minimum, require additional time and result in additional uncertainty and potential challenges to the project.

The availability of groundwater to support this additional need is also questionable. Based on an evaluation of hydrogeology in the area surrounding HGS for the ash landfill solid waste license, only the Madison Limestone and Kootenai formations could potentially produce water to be used for HGS. Based on a nearby well, the Madison formation could potentially produce quantities of water in the above range, although the average yield of area Madison wells is less than the above demand. Further, deep wells would have to be drilled and evaluated and water rights procured. Wells into the Kootenai formation in the area produce water at a rate between 3 and 200 gal/min., with an average yield of 32 gal/min. Based on the hydrogeology report, the Kootenai formation would likely be eliminated as a reliable source of water of this quantity. Water quality would also be a concern for use of groundwater to supplement Missouri River water. A redesign of the water treatment system would potentially be required with additional expense (undetermined at this point).

In addition to the concerns about procuring additional water, the wet ESP system would generate new waste streams in the form of water requiring treatment and discharge, and sludge requiring landfill disposal. This results in two issues for SME: wastewater discharge permitting and solid waste licensing for HGS.

Costs for treating the wastewater from the wet ESP system have been estimated and included in the BACT cost analysis for that control equipment. However, the impact of the wet ESP wastewater on the current plan to deliver HGS wastewater to the City of Great Falls under the auspices of an industrial discharge permitting arrangement has not been evaluated. At a minimum, wet ESP wastewater constituents will need to be evaluated and included in a revised application for an Industrial User Discharge permit from the City of Great Falls.

The current solid waste disposal system at HGS is a dry system and has received a solid waste license from MDEQ based on this design. The introduction of a wet waste stream, at a minimum, will require SME to re-visit the solid waste licensing process. It may also require re-design of the ash landfill, including the proposed liner for the landfill, with resultant undefined significant costs to the project.

The NSR Manual indicates that impacts of control alternatives to water and land resources be considered in the BACT decision-making process. Because the application of a wet air pollution control technology (e.g., wet ESP) fundamentally shifts the pollution control from entirely dry (current design) to one with a wet control device, a significant shift in environmental impact occurs. It is difficult to assess the adverse impacts to the project that would result from permitting these changes without actually proceeding with permit revisions, but they will be significant. Given local and nationwide concerns about water quality impacts from coal-fired electric generating units, trading one environmental impact for another (i.e., removing a small amount of additional air pollution while creating more impacts to land and water) is a trade-off that should be carefully considered in this analysis.

SME also believes that the lack of a filter cake on an FFB, or more specifically the lack of an FFB will lead to reduced SO_2 control effectiveness, because the filter cake in the FFB is estimated to have additional post-CFB boiler SO_2 emissions control. This reduced SO_2 control efficiency will endanger compliance with the existing SO_2 BACT-derived limits. This combination of control technologies will result in SME losing its guarantees for emissions limits in the existing permit. Finally, Alstom engineers report that WESP devices are not capable of handling the heavy particulate loading from a CFB boiler and would only be appropriate as a secondary particulate control device. Technical feasibility of this alternative is therefore suspect.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of dry EDFGD and EWESP would require 1.23 MW of power (approximate). This reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are relevant costs and economic impacts related to **System #26 – EDFGD + EWESP**.

Total estimated capital cost	$96 million
Total annualized cost	$22.1 million/yr
Annual $PM_{2.5}$ emissions reduced	19,154 tons/yr
Annual $PM_{2.5}$ emissions remaining	166 tons/yr
Average cost-effectiveness	$1,156/ton
Incremental cost-effectiveness (relative to next most effective alternative)	$275,396/ton
Incremental cost-effectiveness vs. chosen BACT alternative	$85,367/ton
Pollution control cost per MW-hr	$10.64/MW-hr
Pollution control cost as percentage of projected power price ($70 per MW-hr)	15.20%

Conclusion

SME concludes that System #26 – consisting of Enhanced Dry FGD, followed by Enhanced Wet ESP – is not "achievable" in the present case and is therefore not BACT. This conclusion is based on the above evaluations of adverse environmental and economic impacts. The primary factors are the production of a wet waste stream that would require extensive processing and problematic disposal, additional water volumes that may not be attainable and that would significantly impact project schedule and costs, possible reduction of SO_2 control efficiency, potential inability of the WESP to handle particulate loading from a CFB boiler without an upstream particulate control device and, finally, direct economic impacts that substantially exceed those experienced by other utilities as a result of employing BACT.

The economic impact of System #26 can also be seen in the capital and annualized costs of pollution control (for this alternative) of $96 million and $22.1 million, respectively. When these pollution control costs are related to the projected price of electricity, an additional $10.64/MW-hr would be required, raising the cost of power by 15%. Further, $275,396 to remove each additional ton of $PM_{2.5}$ that would not be removed by the next most effective alternative is an unreasonable incremental cost. Finally, the average cost-effectiveness of this alternative is also quite high, both considering the number of tons of pollutants removed across this multiple technology control system, and in relation to industry norms (see Item 1 above).

The next most effective control alternative listed in Table 5-1 will be evaluated below to determine whether it is BACT for this application.

System #22 – Dry FGD + Enhanced Wet Electrostatic Precipitator

Environmental Impacts

Wet ESP will require that water be provided, treated, and discharged. SME has a contract with the City of Great Falls to provide water that is required for potable uses, cooling and general plant operation. For the City to provide water to HGS from Morony Pool, they had to request and secure a point of diversion change for an existing water reservation from the Montana Department of Natural Resources. That process took several years, including a challenge to the point of diversion change from PPL-Montana that had to be worked through.

It is estimated that the existing contracted water supply rate exceeds the HGS facility's projected total water requirements by approximately 50 gal/min. The boiler designer estimates a wet ESP would require approximately 250 gal/min of water. This amount, when added to current plant operational water requirements, exceeds SME's contracted water supply limit by approximately 200 gal/min. From conversations with the City, additional water would potentially be available; however, a revised contract and similar point of diversion change process to that described above would be needed to make it available to HGS. That process would, at a minimum, require additional time and result in additional uncertainty and potential challenges to the project.

The availability of groundwater to support this additional need is also questionable. Based on an evaluation of hydrogeology in the area surrounding HGS for the ash landfill solid waste license, only the Madison Limestone and Kootenai formations could potentially produce water to be used for HGS. Based on a nearby well, the Madison formation could potentially produce quantities of water in the above range, although the average yield of area Madison wells is less than the above demand. Further, deep wells would have to be drilled and evaluated and water rights procured. Wells into the Kootenai formation in the area produce water at a rate between 3 and 200 gal/min., with an average yield of 32 gal/min. Based on the hydrogeology report, the Kootenai formation would likely be eliminated as a reliable source of water of this quantity. Water quality would also be a concern for use of groundwater to supplement Missouri River water. A redesign of the water treatment system would potentially be required with additional expense (undetermined at this point).

In addition to the concerns about procuring additional water, the wet ESP system would generate new waste streams in the form of water requiring treatment and discharge, and sludge requiring landfill disposal. This results in two issues for SME: wastewater discharge permitting and solid waste licensing for HGS.

Costs for treating the wastewater from the wet ESP system have been estimated and included in the BACT cost analysis for that control equipment. However, the impact of the wet ESP wastewater on the current plan to deliver HGS wastewater to the City of Great Falls under the auspices of an industrial discharge permitting arrangement has not been evaluated. At a minimum, wet ESP wastewater constituents will need to be evaluated and included in a revised application for an Industrial User Discharge permit from the City of Great Falls.

The current solid waste disposal system at HGS is a dry system and has received a solid waste license from MDEQ based on this design. The introduction of a wet waste stream, at a minimum, will require SME to re-visit the solid waste licensing process. It may also require re-design of the ash landfill, including the proposed liner for the landfill, with resultant undefined significant costs to the project.

The NSR Manual indicates that impacts of control alternatives to water and land resources be considered in the BACT decision-making process. Because the application of a wet air pollution control technology (e.g., wet ESP) fundamentally shifts the pollution control from entirely dry

(current design) to one with a wet control device, a significant shift in environmental impact occurs. It is difficult to assess the adverse impacts to the project that would result from permitting these changes without actually proceeding with permit revisions, but they will be significant. Given local and nationwide concerns about water quality impacts from coal-fired electric generating units, trading one environmental impact for another (i.e., removing a small amount of additional air pollution while creating more impacts to land and water) is a trade-off that should be carefully considered in this analysis.
SME believes that the lack of a filter cake on an FFB, or more specifically the lack of an FFB will lead to reduced SO_2 control effectiveness, because the filter cake in the FFB is estimated to have additional post-CFB boiler SO_2 emissions control. This reduced SO_2 control efficiency may endanger compliance with the existing SO_2 BACT-derived limits. This combination of control technologies will result in SME losing its guarantees for emissions limits in the existing permit. Finally, Alstom engineers report that WESP devices are not capable of handling the heavy particulate loading from a CFB boiler and would only be appropriate as a secondary particulate control device. Technical feasibility of this alternative is therefore suspect.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of a DFGD + EWESP would require 1.14 MW of power (approximate). This reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are relevant costs and economic impacts related to **System #22 – DFGD + EWESP**.

Total estimated capital cost	\$91 million
Total annualized cost	\$21.1 million/yr
Annual $PM_{2.5}$ emissions reduced	19,150 tons/yr
Annual $PM_{2.5}$ emissions remaining	170 tons/yr
Average cost-effectiveness	\$1,103/ton
Incremental cost-effectiveness (relative to next most effective alternative)	\$82,562/ton
Incremental cost-effectiveness vs. chosen BACT alternative	\$73,107/ton
Pollution control cost per MW-hr	\$10.16/MW-hr
Pollution control cost as percentage of projected power price (\$70 per MW-hr)	14.51%

Conclusion

SME concludes that System #22 – consisting of Dry FGD, followed by Enhanced Wet ESP is not "achievable" in the present case and is therefore not BACT. This conclusion is based on the above evaluation of adverse environmental impacts, possible reduction of SO_2 control efficiency, potential inability of the WESP to handle particulate loading from a CFB boiler without an upstream particulate control device, and economic impacts that substantially exceed those experienced by other utilities as a result of employing BACT.

The economic impact of System #22 can also be seen in the capital and annualized costs of pollution control (for this alternative) of \$91 million and \$21.1 million, respectively. When these pollution control costs are related to the projected price of electricity, an additional \$10.16/MW-hr would be required, raising the cost of power by 14.5%. Further, $82,562 to remove each additional ton of $PM_{2.5}$ that would not be removed by the next most effective alternative is an unreasonable incremental cost. Finally, the average cost-effectiveness of this alternative is also quite high, both considering the number of tons of pollutants removed across this multiple technology control system, and in relation to industry norms (see Item 1 above).

The next most effective control alternative listed in Table 5-1 will be evaluated below to determine whether it is BACT for this application.

System #11 – Spray Dry Absorber FGD + Electrostatic FFB

Environmental Impacts

By injecting hydrated lime into the exhaust stream with the SDA, approximately 60 tons per day will be added to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

SME has serious concerns about the ability of the "fluidized" filter cake of the ESFFB and its ability to properly control acid gas and SO_2 emissions. The designer and provider of SME's CFB boiler, Alstom, has stated they could not guarantee compliance with SO_2 emissions limits if the ESFFB were used in place of standard or IC filter bags. The ESFFB has not been tested in any system where an SDA or any FGD is used that relies on a baghouse filter cake for additional SO_2 control.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of the SDA and ESFFB would require 1.96 MW of power (approximate). This reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are relevant costs and economic impacts related to **System #11 – SDAFGD + ESFFB**.

Total estimated capital cost	$44 million
Total annualized cost	$18.8 million/yr
Annual $PM_{2.5}$ emissions reduced	19,111 tons/yr
Annual $PM_{2.5}$ emissions remaining	209 tons/yr
Average cost-effectiveness	$983/ton
Incremental cost-effectiveness (relative to next most effective alternative)	$99,020/ton*
Incremental cost-effectiveness vs. chosen BACT alternative	$99,020/ton
Pollution control cost per MW-hr	$9.03/MW-hr
Pollution control cost as percentage of projected power price ($70 per MW-hr)	12.90%

*See note (a) in Figure 5.

Conclusion

SME concludes that System #11 – consisting of Spray Dry Absorber FGD followed by Electrostatic Fabric Filter Baghouse – is not "achievable" in the present case and is therefore not BACT. This conclusion is based on the above evaluations of adverse environmental and economic impacts. Primary factors for this conclusion are the potential degradation in control of SO_2, acid gases, and mercury emissions due to the lack of information about the operation of the ESFFB, and the lack of operating experience with this technology. Further, the ESFFB has only been used on an 87 MW PC-fired boiler with no application on a CFB boiler, or a larger boiler of any type.

Another primary factor for this conclusion is the economic impact of System #11, shown in the annualized and incremental costs of pollution control (for this alternative) of $18.8 million and $99,020/ton, respectively. The average cost-effectiveness of this alternative is also high in relation to industry norms (see Item 1 above).

The next most effective control alternative listed in Table 5-1 will be evaluated next to determine whether it is BACT for this application.

System #18 – Enhanced Dry FGD + FFB with Membrane Filters

Environmental Impacts

By injecting hydrated lime into the exhaust stream, the dry sorbent injection portion of the enhanced FGD will add approximately 20 tons per day to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

SME's analysis described serious concerns regarding the ability of membrane filters to develop and maintain a filter cake sufficient for controlling boiler emissions of several other pollutants to required levels. Information gathered from four other utilities that are using membrane filters confirms this concern. The designer and provider of SME's CFB boiler, Alstom, has stated they could not guarantee compliance with SO_2 emissions limits if the membrane bags were used in place of standard or IC filter bags. SME believes SO_2 emissions would increase to a level endangering compliance with BACT-derived emission limits for SO_2. Replacing IC fabric bags with membrane bags would also likely increase emissions of H_2SO_4, HF, HCl, and mercury, all of which have emission rate limits in the existing permit. By utilizing membrane bags, SME believes we would be trading an increase in filterable particulate control for a decrease in condensable particulate control. This becomes a catch-22 as increasing SO_2 emissions increase $PM_{2.5}$ precursor emissions as well. Also, by increasing HGS's acid gas emissions, the system would further contribute to HAP emissions, jeopardizing SME's proposal for minor (area) source status included in a recent submittal.

Energy Impacts

All of the equipment in this system would require electrical power. The addition of the EDFGD + MFFB system would require 1.34 MW of power (approximate). This reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are the relevant costs and economic impacts related to **System #18 – EDFGD + MFFB**.

Total estimated capital cost	$57 million
Total annualized cost	$16.6 million/yr
Annual $PM_{2.5}$ emissions reduced	19,108 tons/yr
Annual $PM_{2.5}$ emissions remaining	212 tons/yr
Average cost-effectiveness	$871/ton
Incremental cost-effectiveness (relative to next most effective alternative)	$-20,785/ton
Incremental cost-effectiveness vs. chosen BACT alternative	$-20,785/ton
Pollution control cost per MW-hr	$8.00/MW-hr
Pollution control cost as percentage of projected power price ($70 per MW-hr)	11.42%

Conclusion

SME concludes that System #18 – consisting of Enhanced Dry FGD followed by FFB with Membrane Filters – is not "achievable" in the present case and is therefore not BACT. This conclusion is based on the above evaluations of adverse environmental impacts. The primary factor is a potentially significant degradation in control of SO_2, acid gases, and mercury emissions due to the properties of the membrane filters.

The next most effective control alternative listed in Table 5-1 will be evaluated below to determine whether it is BACT for this application.

System #16 – Enhanced Dry FGD + FFB with IC Filters

Environmental Impacts

By injecting hydrated lime into the exhaust stream, the dry sorbent injection portion of the enhanced FGD will add approximately 20 tons per day to the solid waste produced by the control system. This waste will require disposal in a licensed landfill.

Energy Impacts

This system would require 1.68 MW of electrical power. This amount of power is estimated to be similar to the system (#9) that has been previously accepted as BACT for other pollutants in the current air quality permit. This energy demand reduces overall efficiency of the boiler and, by doing so, marginally offsets some of the additional pollution control due to the need to burn additional coal to provide the system electricity demands.

Economic Impacts

Listed below are the relevant costs and economic impacts related to **System #16 – EDFGD + ICFFB**.

Total estimated capital cost	$57 million
Total annualized cost	$16.9 million/yr
Annual $PM_{2.5}$ emissions reduced	19,093 tons/yr
Annual $PM_{2.5}$ emissions remaining	227 tons/yr
Average cost-effectiveness	$888/ton
Incremental cost-effectiveness (relative to next most effective alternative)	$84,899/ton*
Incremental cost-effectiveness vs. chosen BACT alternative	NA
Pollution control cost per MW-hr	$8.15/MW-hr
Pollution control cost as percentage of projected power price ($70 per MW-hr)	11.65%

*See note (a) in Figure 5.

Conclusion

SME concludes that System #16 – consisting of Enhanced Dry FGD followed by FFB with IC Filters – cannot be eliminated due to any adverse environmental, energy, or economic reasons listed above.

SME has previously committed in writing to MDEQ to install this system and become a minor source of hazardous air pollutants. The change in HAP emissions status would be effected by further controlling acid gas emissions below levels required in Air Quality Permit #3423-00. At an average cost-effectiveness of $888/ton of $PM_{2.5}$, the system is costly compared to other facility BACT analyses for particulate matter; however, when compared to other control options in this BACT analysis, it reaches a reasonable balance between emissions reduction and costs. The proposed system is significantly more expensive than SME's current permitted emissions control system as demonstrated by an incremental cost of approximately $41,000/ton for $PM_{2.5}$. The cost is acceptable in this case to achieve overall environmental objectives and provide additional acid gas control. The system provides excellent emissions control for $PM_{2.5}$, PM_{10}, SO_2 , acid gases, and mercury; further, Alstom, the boiler and pollution control system manufacturer, guarantees the proposed system will achieve current emissions limits for the above pollutants. While the NSR Manual tends to undervalue guarantees from control equipment suppliers, we believe that having the supplier/manufacturer stand behind their equipment through a guarantee should be considered carefully by both applicant and regulatory agency. Neither party is well served when installed equipment fails to live up to expectations, resulting in emissions exceedances and a disappointed public.

On the above basis, the system is determined to be achievable, and since it has acceptable environmental and energy impacts and costs, it is determined to be BACT for HGS for total $PM_{2.5}$ in this application. No further analysis of any lower ranking systems is required.

Step 5 - Select BACT for $PM_{2.5}$ Control

In Step 4, SME concluded that System #16, consisting of Enhanced Dry FGD followed by FFB with IC Filters, was BACT for $PM_{2.5}$ control for the HGS facility. To assure an appropriate selection, SME completed a common sense review of the BACT analysis. The purpose of this review is to make sure that contending control technologies were not missed and to confirm that a control option was chosen that will effectively control $PM_{2.5}$ emissions (both primary and secondary, along with precursors). The review also serves to ensure that the result of the analysis aligns with the overall purpose of the PSD program, which is to protect air quality while providing for economic growth. This latter objective is especially important since the NSR Manual's BACT analysis process, while providing a useful foundation for a degree of standardization, is limited by the quality and quantity of available case-specific information. The nature of a BACT analysis requires the use of many assumptions and estimates which can produce results that may not be consistent with principles of science and engineering.

To complete this common sense review, SME reviewed the control option screening process, the detailed top-down BACT analysis of the resulting 14 control options after screening and, finally, the selection of BACT from the process as follows:

- As discussed in Step 3 of this BACT analysis, the creation of a vast number of control options tends to cloud the BACT selection process, without providing much differentiation between alternatives. Traditionally, BACT analyses have effectively screened potential alternatives in Steps 1 and 2 to identify appropriate control options for further analysis. Nonetheless, as an outcome of this evolving BACT process, SME has carried the large number of control options (105 vs. 20 options submitted by SME previously) into a screening procedure based on a "least cost envelope" analysis outlined in the NSR Manual. The question following this screening process is whether any representative and viable control options (i.e., true contenders for $PM_{2.5}$ BACT) were somehow excluded during screening.

  As explained in the screening process above, the use of a least cost envelope to identify "dominant" alternatives for further analysis is discussed in the NSR Manual and fits well within the BACT procedure (based on cost-effectiveness of control technologies). Further, it was required by the development of a large number of control options as MDEQ believed the BER directed. Failure to screen the 105 alternatives would result in an impossible BACT process, with little ability to differentiate between alternatives.

  A review of the ranked control options in Table 5-1 shows that key technologies for controlling $PM_{2.5}$ are well represented. FGD processes are present in all alternatives except one, EWESP, and EWESP is the only single control device with combined condensable and filterable $PM_{2.5}$ control capabilities. Particulate control devices, including both wet and dry ESP and FFB – membrane, intrinsically coated bags, and the newly developed ESFFB – are all represented in the control options to be considered in the top-down analysis. Further, several control options provide multiple control technologies in series, providing higher control efficiencies but with much lower cost-effectiveness due to diminishing returns as inlet pollutant levels drop.

  A review of the control efficiency range represented covers the range of 98.3 to 99.9%, as compared to the entire control efficiency range from Table 0-4 of 93 to 99.9+%. This check shows good control efficiency coverage of the control options, without over-representation from underperforming controls (i.e., less than 98% control) or from controls clustered at 99.9+%, which dominate the list of control options reported in Step 3.

As a result of this common sense review, SME concludes the screening procedure provides a representative and appropriate list of control options for detailed analysis in Step 4 of the top-down BACT analysis.

- The detailed top-down BACT analysis conducted in Step 4 for $PM_{2.5}$ emissions control appropriately started at the control efficiency with the highest pollutant removal of the screened control options. Based on the NSR Manual criteria, energy and environmental impacts for each alternative were documented, and a determination of average and incremental cost-effectiveness was completed. Also as suggested in the manual, a BACT assessment and, if appropriate, rejection was completed for each control option before moving to the next control option in descending order of control efficiency.

  It is difficult to judge the result of a top-down BACT process until it is complete and one can step back and assess the outcome. In this analysis, the control option determined to be BACT lies in the middle of the pack (#7 out of 14 ranked alternatives for $PM_{2.5}$ control). Given the heavy weighting of multiple control device options in the original 105 control options, this outcome supports a reasonable screening process. At approximately 98.8% $PM_{2.5}$ control, Control Option #16 is only 0.1% below the top alternative considered in the analysis (difference of approximately 200 tons of $PM_{2.5}$). To control this additional $PM_{2.5}$ nearly doubles the annualized costs ($29.2 million for top alternative vs. $16.9 million for BACT control option).

  Another look at the BACT selection keys on average cost-effectiveness. The average cost-effectiveness of Control Option #16 is $888/ton, within a range of $1512/ton for the top alternative to $652/ton for the lowest ranked alternative in the 14 control options considered in this analysis. Realizing the NSR Manual does not direct control costs to be "average" among options, this check provides some measure of the selected alternative. As an additional check on cost-effectiveness (beyond the examples provided above for two facilities in WY and UT), SME surveyed the EPA RBLC database for particulate matter (PM) and PM_{10} cost-effectiveness entries. Recognizing these entries are for different size range particulate matter, they are nonetheless a data set to relate to. The RBLC search found PM_{10} cost-effectiveness ranging from $31/ton to $252/ton; PM cost-effectiveness values ranged from $6/ton to $252/ton. See Appendix C for RBLC search results. Clearly, the selected BACT option has an average $PM_{2.5}$ cost-effectiveness well above these previous PM and PM_{10} determinations (see Appendix C).

- From a look at Figure 3 above, and a review of the control alternatives in Table 0-4, a group of BACT "competitors" can be ascertained based on annualized costs of between $15 million and $20 million, and control of 19,080 to 19,110 tons of $PM_{2.5}$. These "competitors" include the following options:

System #	Technology
11	SDAFGD + ESFFB
18	EDFGD + MFFB
16	EDFGD + ICFFB
7	EWESP

At this point in the review, an evaluation of these "competitors" aids in assuring an appropriate BACT determination is being made.

System #11: SDA + ESFFB – As discussed above and in the record, the GE Max-9™ technology, an electrostatic fabric filter, is a hybridized device, with reported advantages in fine particulate collection and reduced pressure drop compared to standard baghouses. A closer look at the technology shows it is still in early commercial development, with one installation on a smaller PC-fired boiler. Further evaluation of the technology identified a technical problem with handling particulate loading downstream of an HAR FGD device; therefore, an SDA was substituted in place of the HAR for this BACT analysis to attempt to address this problem. However, it should be noted that the ESFFB has never been demonstrated downstream of an FGD device, so its application in this instance is projected, not demonstrated. Finally, GE was unable to produce emissions test data for PM_{10} or $PM_{2.5}$, so engineering projections on its effectiveness as a $PM_{2.5}$ control device had to be made for this analysis. Although it rises to the surface in this analysis as a "competitor" for BACT based on cost and estimated performance, its lack of application and performance data bring into question potential emissions control performance when applied to HGS. GE markets the technology as an "add-on, polishing" device for older facilities looking to improve their emissions performance (emphasized by its single application as a polishing device on the Allegheny Power R. Paul Smith Generating Unit). Because it has the highest annualized cost and offers only potential (undefined) advantages over the other control options in this group, and because of its "unproven" status, SME concludes this technology does not qualify as BACT for $PM_{2.5}$ control at HGS.

System #18: EDFGD + MFFB - This control option adds hydrated lime injection to SME's permitted FGD system to obtain additional acid gas removal and thereby achieve minor source status for HAPs emissions. However, using an FFB with membrane bags following the EDFGD would potentially increase, relative to other control alternatives, emissions of SO_2, acid gases, and mercury and prevent compliance with associated permit limits. As explained in this and previous submittals, the MFFB allows the formation of only a limited filter cake on the bags; while this factor assists in lowering pressure drop across the bags, it degrades a key emissions control function for SO_2, acid gases, and mercury. Although membrane bags are reported to be more efficient at filtering $PM_{2.5}$ than conventional bags, there is a significant tradeoff in lost efficiency for other pollutants. If we assume a worst case loss of 20-30% of SO_2 control, emissions would potentially increase by thousands of tons per year. Clearly, risking a significant increase in SO_2, which is the leading $PM_{2.5}$ precursor, to gain approximately 15 tons/year of $PM_{2.5}$ reductions with this system compared to System #16 is inappropriate.

System #16: EDFGD + ICFFB - This system is similar to System #18, except it utilizes an FFB with intrinsically coated bags for particulate matter control. Additional costs over SME's currently permitted emissions control system are caused by the "enhancement" to the

FGD system – a hydrated lime injection system. This system provides further acid gas reduction beyond the currently permitted HAR FGD and ICFFB control system, and enhances the ability of the system to achieve stringent SO_2 emissions limits. While this system is relatively expensive compared to other particulate matter BACT determinations at $888/ton and an annualized cost of $16.9 million, those costs are related to meeting environmental objectives for the facility and are therefore deemed acceptable. A review of the recently permitted Deseret Rock Power Generation Facility on the Navajo Reservation in New Mexico supports the use of hydrated lime injection for acid gas control; that facility chose this technology to control their acid gases.

System #7: EWESP - This control system ranks below the selected BACT alternative and therefore was not analyzed further in the top-down BACT process. The placement of this control system in the final "competitors" group demonstrates the potential effectiveness of WESP in controlling $PM_{2.5}$ emissions. However, the technology is very expensive and turns the emissions control system at HGS into a wet system, resulting in impacts to water and land. Further tradeoffs exist when using this technology without an FGD system in loss of emissions control function for SO_2 and mercury. As explained above, SO_2 is a key precursor in forming $PM_{2.5}$ emissions in the atmosphere downwind of the facility. Finally, Alstom engineers have reported that a WESP is not capable of handling the heavy particulate loading downstream of a CFB boiler and so is not suited as a primary particulate control device for this application. For these reasons, EWESP is not a viable candidate for $PM_{2.5}$ BACT for this facility.

Based on the above review, SME proposes that Control System #16 is BACT for control of total $PM_{2.5}$ in this application.

Table 0-1, Table 0-2, and Table 6-3 summarize the results of Step 4 of this BACT analysis.

Table 0-1: Energy Impact Summary

Control Option #	Rank	Energy Impacts		Adverse Energy Impact
		Parasitic Power Demand (MW)	Parasitic Power Percentage of Facilities Output (%)	
65	41	2.06	0.83%	Yes
38	58	2.61	1.04%	Yes
26	66	1.23	0.49%	**No**
22	67	1.14	0.46%	**No**
11	79	1.96	0.78%	Yes
18	80	1.34	0.54%	**No**
16	81	1.68	0.67%	**No**

Table 0-2: Environmental Impact Summary

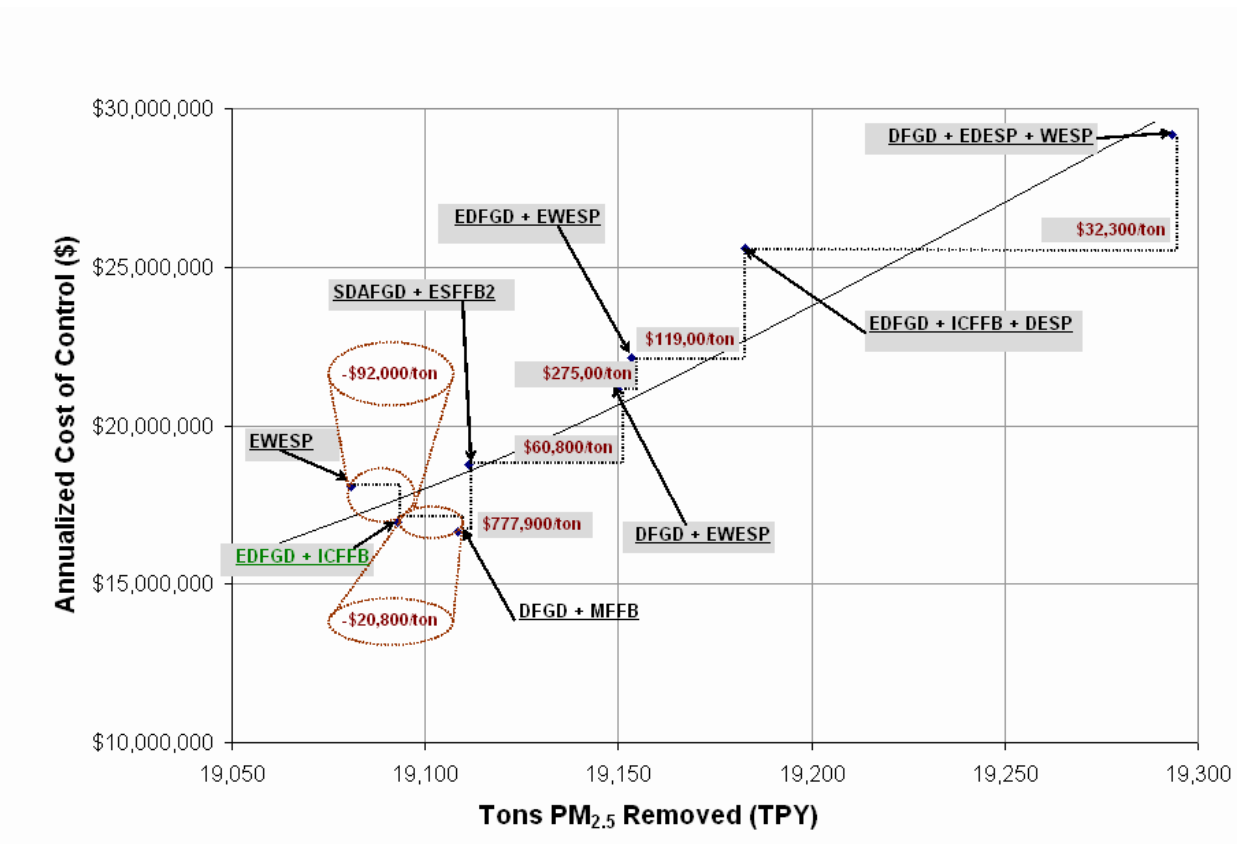
Control Option #	Rank	Environmental Related Impacts	Adverse Environmental Impact
65	41	20 tons per day added solid waste; exceed avail. water supply by nearly 200 gal/min; treatment and disposal of new waste streams; reduction of SO_2 control efficiency	Yes
38	58	20 tons per day added solid waste	**No**
26	66	20 tons per day added solid waste; exceed avail. water supply by nearly 200 gal/min; treatment and disposal of new waste streams; reduction on SO_2 control efficiency	Yes
22	67	20 tons per day added solid waste; exceed avail. water supply by nearly 200 gal/min; treatment and disposal of new waste streams; reduction on SO_2 control efficiency	Yes
11	79	60 tons per day added solid waste; reduced SO_2 and acid gas control efficiency	Yes
18	80	20 tons per day added solid waste; reduced SO_2 and acid gas control efficiency	Yes
16	81	20 tons per day added solid waste	**No**

Table 0-3: Economic Impact Summary

Control Option #	Rank	Economic Related Impacts				Economic Effectiveness		Adverse Economic Impact
		Controlled Direct PM2.5 Emissions (Tons/Year)	Annualized Cost	Percentage of Power Price (%)	Total Annual Cost of Control Equipment ($/MWh Produced)	Incremental ($/Ton of $PM_{2.5}$ Controlled)	Average ($/Ton of $PM_{2.5}$ Controlled)	
65	41	19,293	$29,184,057	20.04	$14.03	$32,333	$1,513	Yes
38	58	19,183	$25,605,523	17.58	$12.31	$118,722	$1,335	Yes
26	66	19,154	$22,143,112	15.20	$10.64	$275,396	$1,156	Yes
22	67	19,150	$21,129,654	14.51	$10.16	$60,768	$1,103	Yes
11	79	19,111	$18,781,591	12.90	$9.03	$777,916	$983	Yes
18	80	19,108	$16,634,544	11.42	$8.00	($20,785)	$870.54	**No**
16	81	19,093	$16,959,620	11.65	$8.15	($92,002)	$888	**No**

Figure 6 graphically illustrates the calculation method and results of the incremental costs reported above.

Figure 6: Incremental Costs



BACT as a Limit

ARM 17.8.740 defines BACT as "… an emission limitation (including visible emissions standard), based on the maximum degree of reduction for each pollutant subject to regulation under 42 U.S.C. 7410, *et seq*. or 75-2-101, *et seq.*, MCA, that would be emitted from any proposed emitting unit or modification which the Department, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such emitting unit or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such contaminant. In no event may application of BACT result in emissions of any regulated air pollutant that would exceed the emissions allowed by any applicable standard under ARM 17, chapter 8, subchapter 3, and this subchapter. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular class of emitting units would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or operational standard or combination thereof, to require the application of BACT. Such standard must, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice, or operation and must provide for compliance by means that achieve equivalent results."

Previous $PM_{2.5}$ BACT submittals by SME in June and July, 2008, proposed $PM_{2.5}$ BACT emissions limits based on the analysis and work with SME engineers and the boiler manufacturer. After review of those submittals, the Department issued a preliminary BACT review on August 15 that proposed a "design, equipment, work practice" (work practice) limit in lieu of an emissions limit, as allowed in the BACT rules described above. SME concurs with many of the Department's points in suggesting a work practice prescription as the outcome of this $PM_{2.5}$ BACT analysis. Therefore, we are including the majority of the Department's proposed write-up in support of this outcome. However, by proposing an emissions limit for $PM_{2.5}$ BACT previously (with an accompanying soft landing to address future changes in reference test methods), SME believes that an appropriately set and worded emissions limit would also be a workable outcome of this analysis.

The Department and SME both note that this $PM_{2.5}$ BACT analysis includes assumptions, estimates, unwarranted numbers of significant digits, and other uncertainties that stem from the lack of available information, data, published $PM_{2.5}$ emission factors for CFB boilers, and measured and proven $PM_{2.5}$ control efficiencies for the analyzed control technologies.

First and foremost, the estimated control efficiencies used in this analysis are implicit and not explicitly based on data resulting from using an approved reference test method or other monitoring methods and analytical techniques that have been proven to provide the accuracy and precision necessary to collect the information needed to establish known control efficiencies. The control efficiency estimates presented in this analysis are estimates based on multiple lines of technical information, not on a single test method. The Department and SME assert that establishing a numeric permit limit for $PM_{2.5}$ based on this analysis, considering these underlying assumptions with regard to control efficiencies, could put the SME HGS in a precarious situation, because the limit itself would be based on estimated control efficiencies that are not tied to a specific test method. Furthermore, as described previously, EPA has not yet promulgated a reference test method for source testing $PM_{2.5}$. Recent communication with EPA (electronic mail correspondence with Ron Meyers, August 11, 2008) indicates OTM 27 and 28 are intended to be promulgated in the future as modifications to current reference methods 201 and 202; however, this may take some time. Therefore, even if a numeric limit was prescribed, there would be no approved test method to demonstrate compliance with that limit in the near term.

Nonetheless, as conducted above, top-down methodology for BACT analysis is a regulatory decision making process (NSR Manual, Page B-2) that results (as defined above) in either specification of an emission limit or a design, equipment, work practice or operation to control air pollutant emissions. In light of the uncertainty in this analysis and those regarding approved reference test methods for $PM_{2.5}$ the following design, equipment, work practice and operational requirements are proposed as the BACT limitations for $PM_{2.5}$ emitted from the SME HGS CFB boiler, to be added to Section C of the permit:

- Equipment - SME shall install an ED-FGD followed by IC-FFB technology to control $PM_{2.5}$ emissions from the CFB boiler in accordance with manufacturer's specifications.

- Design - SME shall submit ED-FGD and IC-FFB design specifications to the Department along with a detailed explanation of how the system will achieve $PM_{2.5}$ emissions control.

- Work Practice and Operation – SME shall operate the IC-FFB at all times during start-up, shutdown and normal operation of the CFB boiler, and maintain the IC-FFB in accordance with manufacturer's specifications.

To demonstrate compliance with the above permit conditions, SME proposes to comply with the following operational reporting and notification requirements:

- Within 180 days of start-up, SME shall provide to the Department a complete Operation and Maintenance Manual for the ED-FGD and IC-FFB apparatus and ancillary equipment. The manual shall identify critical operating parameters such as temperature, pressure drop, gas flow rate, maintenance, cleaning schedules and any other operational parameters essential to proper function of the equipment.

- Within 180 days of start-up, SME shall provide a one-time notification to the Department that the ED-FGD and IC-FFB were constructed to the design specifications provided above. The notification shall be certified by a responsible official, as defined at ARM 17.8.748 (3) (a)-(d).

- SME shall log and report annually (along with information reported in accordance with the condition at Section O.1 of the Permit) operational parameters including lime and ash injection rates in the ED-FGD, pressure drop across the IC-FFB, temperature and flow rate, bag cleaning records, equipment maintenance and replacement logs, and any other pertinent or critical operation and maintenance information as identified in the Operation and Maintenance Manual.

CFB Start-up and Shutdown

CFB boiler start-up and shutdown work practices have been developed and documented as a procedure presented as Attachment 3 to the permit. SME has proposed that BACT for $PM_{2.5}$ during start-up is included in the analysis and procedure already developed for start-up and shutdown with the addition of commencing operation of the baghouse just prior to introduction of first fire on start-up fuels at the beginning of Phase 2 of start-up. The Department indicated they concur with this determination. SME proposes to add the following condition to Section B of the permit as BACT for $PM_{2.5}$ during start-up and shutdown.

- During start-up, SME shall begin operating the IC-FFB just prior to first firing of the boiler on start-up fuels and operation of other pollution control devices as applicable with increasing boiler temperature as described in Attachment 3.

- During shutdown, SME shall continue to operate the IC-FFB until the ID fan is deactivated and all other pollution control equipment shall remain online until minimum operation temperatures are reached as described in Attachment 3 of the permit.

IV. Emission Inventory

ton/year												
Emission Source	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NO_x**	**SO_x**	**CO**	**VOC**	**Pb**	**Hg**	**HCl**	**HF**	**H_2SO_4**
CFB Boiler (2626 MMBtu/hr)	138.0	299.1	227	805.2	437.1	1150.2	34.5	0.035	0.02	9.3	8.2	62.11
Aux. Boiler (225 MMBtu/hr)	1.4	1.4		19.9	5.4	7.9	0.5	0.000862	0.000287	---	---	---
Emergency Generator	0.13	0.13		10.3	0.3	0.7	0.2	---	---	---	---	---
Emergency Fire Water Pump	0.04	0.04		0.9	0.03	0.2	0.03	---	---	---	---	---
Coal Thawing Shed	0.03	0.03		1.0	0.00	0.17	0.03	---	---	---	---	---
Car Unloading Baghouse (DC1)	24.4	24.4		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Silo Baghouse (DC2)	3.6	3.6		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Crusher Baghouse (DC3)	2.8	2.8		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tripper System Baghouse (DC4)	3.8	3.8		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limestone Baghouse (DC5)	5.0	5.0		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fly-Ash Silo Bin Vent (DC6)	1.5	1.5		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bed-Ash Silo Bin Vent (DC7)	1.4	1.4		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Pile Dressing	1.7	0.3		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Transfers	3.4	1.6		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Storage	3.3	1.6		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ash Landfill (Truck Dump)	3.2	1.6		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	13.53	13.53		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Truck Traffic	4.8	1.0		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Building Heaters	0.28	0.28		9.72	0.01	1.32	0.35	0.0000335	0.0000174	---	---	---
Fuel Oil Storage Tank	0.00	0.00		0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
Refractory Brick Curing Heaters (2771 MMBtu/hr)	3.05	3.05		96.65	0.09	16.28	2.36	---	---	---	---	---
Total Emissions	**215**	**366**	**227**	**944**	**443**	**1177**	**38**	**0.036**	**0.02**	**9.3**	**8.5**	**62.11**
* CFB Boiler PM emissions represent only front-half filterable PM emissions. Total PM emissions including PM_{10} and condensable PM emissions are estimated under the column for CFB Boiler PM_{10} and also included under $PM_{2.5}$ column emissions.												
A complete emission inventory for Permit #3423-01 is on file with the Department												

CFB Boiler Emissions

Heat Input: 2626.1 MMBtu/hr (Average Annual Heat Input – Manufacturers Information)
Hours of Operation: 8760 hr/yr (Annual Potential)

Filterable PM Emissions

Emission Factor: 0.012 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.012 lb/MMBtu = 31.51 lb/hr
31.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 138.03 ton/yr

PM_{10} Emissions (filterable and condensable)

Emission Factor: 0.026 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.026 lb/MMBtu = 68.28 lb/hr
68.28 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 299.06 ton/yr

$PM_{2.5}$ Emissions (filterable and condensable)

Emission Factor: 0.020 lb/MMBtu (BACT determination #3423-01)
Calculations: 2626.1 MMBtu/hr * 0.020 lb/MMBtu = 51.83 lb/hr
51.83 * 8760 hr/yr * 0.0005 ton/lb = 227 ton/yr

NO_x Emissions

Emission Factor: 0.07 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.07 lb/MMBtu = 183.83 lb/hr
183.83 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 805.16 ton/yr

SO_x Emissions

Emission Factor: 0.038 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.038 lb/MMBtu = 99.79 lb/hr
99.79 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 437.09 ton/yr

CO Emissions

Emission Factor: 0.10 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.10 lb/MMBtu = 262.61 lb/hr
262.61 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1150.23 ton/yr

VOC Emissions

Emission Factor: 0.003 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.003 lb/MMBtu = 7.88 lb/hr
7.88 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 34.51 ton/yr

Hg Emissions

Emission Factor: 1.50E-06 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 1.50E-06 lb/MMBtu = 0.0039 lb/hr
0.0039 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.017 ton/yr

HCl Emissions

Emission Factor: 0.00085 lb/MMBtu (Hourly BACT Limit Permit #3423-01)
Calculations: 2626.1 MMBtu/hr * 0.00085 lb/MMBtu = 2.23 lb/hr
2.23 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 9.3 ton/yr

HF Emissions

Emission Factor: 0.00075 lb/MMBtu (Hourly BACT Limit Permit #3423-01)
Calculations: 2626.1 MMBtu/hr * 0.00075 lb/MMBtu = 1.97 lb/hr
1.97 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 8.2 ton/yr

H_2SO_4 Emissions

Emission Factor: 0.0054 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0054 lb/MMBtu = 14.18 lb/hr
14.18 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 62.11 ton/yr

V. Existing Air Quality

The air quality classification for the SME-HGS project area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. However, the facility will locate in an area that has recently been re-designated attainment for CO under a limited maintenance plan. The SME-HGS facility has not been identified in any studies as impacting the previous CO nonattainment area.

Under the requirements of the PSD program, SME-HGS was required to conduct modeling to determine pollutant-specific pre-monitoring applicability. Because air modeling showed that the concentration of PM_{10} exceeded the level identified in ARM 17.8.818(7), SME-HGS was required to conduct on-site pre-monitoring for this pollutant. SME-HGS collected PM_{10} pre-monitoring data at the proposed site from November 12, 2004, through November 11, 2005. The following table lists the background monitoring data from the SME-HGS PM_{10} monitoring site. The measured PM_{10} values establish the baseline concentrations and demonstrate compliance with all applicable ambient air quality standards.

PM_{10} Pre-monitoring Results

Pollutant	Avg. Period	High Impact (ppm)	High Impact ($\mu g/m^3$)	HSH Impact (ppm)	HSH Impact ($\mu g/m^3$)	Ambient Standard[a] ($\mu g/m^3$)	% of Standard
PM_{10}	24-hr	------	23	------	19	150	13
	Annual	------	7	------	------	50	14

[a] MAAQS and NAAQS

VI. Ambient Air Impact Analysis

As presented for MAQP #3423-00 the following ambient air impact analysis is applicable.

The nearest PSD Class I area is the Gates of the Mountains Wilderness Area located approximately 53 miles [85 kilometers (km)] southwest of the proposed site. Impacts have also been evaluated at these other Class I areas within 250 km of the site: Scapegoat Wilderness Area, Bob Marshall Wilderness Area, Glacier National Park, Mission Mountains Wilderness Area, UL Bend Wilderness Area, and Anaconda Pintler Wilderness Area. Bison Engineering, Inc. (Bison) submitted modeling on behalf of SME-HGS.

Emissions of NO_x, SO_2, CO, PM_{10}, $PM_{2.5}$ and Pb were modeled to demonstrate compliance with the NAAQS and Montana Ambient Air Quality Standards (MAAQS) and the PSD increments. On December 15, 2006, the Departmemt received revised modeling of the HGS facility. The new modeling is based on the changed footprint of the facility, which will be permitted at both the original and the alternative footprint. Changing the locations of the emission points within the property boundary had very little impact on the modeled impacts. The original modeling followed the model selection criteria contained in Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003. The revised modeling followed the November 9, 2005 version of Appendix W, with the primary change being the use of the AERMOD model instead of the older ISC-PRIME model. SME's original Class II modeling used five years of surface meteorological data (1984, 1986-1991) collected at the Great Falls Airport National Weather Service (NWS) station. The AERMOD modeling for the alternative location used EPA SCRAM hourly surface data from the Great Falls NWS site for the years 1999-2003. Surface met data was processed with corresponding upper air data from the Great Falls NWS station. The highest impact from the two modeling submittals is listed for each pollutant and averaging period in the tables below.

SME-HGS submitted a significant impact analysis based on emissions from all proposed SME-HGS sources, including the CFB Boiler refractory brick curing heater(s) proposed under the supplemental preliminary determination. The modeled SME-HGS impacts are compared to the applicable Class II significant impact levels (SIL's) in Table 1. The SILs are contained in Table C-4 of the NSR Manual. The impacts exceed the SIL's for PM_{10}, NO_x and SO_2; therefore, a cumulative impact analysis is required for these pollutants to demonstrate compliance with the NAAQS/MAAQS. The radius of impact (ROI) for each pollutant and averaging period is included in Table 1.

Table 1: SME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Class II SIL[a] ($\mu g/m^3$)	Significant (y/n)	Radius of Impact (km)
PM_{10}	24-hr	18.7	5 (1)[b]	Y	3.0
	Annual	3.1	1	Y	1.4
NO_x [c]	Annual	1.6	1	Y	0.7
CO	1-hr	90.3	2,000	N	------
	8-hr	26.9	500	N	------
SO_2	3-hr	15.9	25	N	------
	24-hr	7.4	5 (1)[b]	Y	0.7
	Annual	0.24	1	N	------
O_3	Net Increase of VOC: 35.6 tpy. Less than 100 tpy, source is exempt from O_3 analysis.				

[a] All concentrations are 1st-high for comparison to SIL's.
[b] If a proposed source is located w/in 100 km of a Class I area, an impact of 1 $\mu g/m^3$ on a 24-hour basis is significant.
[c] Significant impact area (SIA) based on NO_x impact (rather than NO_2).

NAAQS/MAAQS modeling was conducted for PM_{10}, SO_2, and NO_x. CO impacts from SME-HGS alone were below the modeling significance level and no additional modeling was conducted for CO emissions. The full ambient impact analysis included emissions from other industrial sources in the Great Falls area.

Modeling results are compared to the applicable NAAQS/MAAQS in Table 2. Modeled concentrations show the impacts from SME-HGS and off-site sources and include the background values. As shown in Table 2, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 2: SME-HGS NAAQS/MAAQS Compliance Demonstration

Pollu-tant	Avg. Period	Modeled Conc.[a] (μg/m³)	Backgrnd Conc. (μg/m³)	Ambient Conc. (μg/m³)	NAAQS (μg/m³)	% of NAAQS	MAAQS (μg/m³)	% of MAAQS
PM_{10}	24-hr	10.5	23	33.5	150	22	150	22
	Annual	3.2	7	10.2	50	20	50	20
$PM_{2.5}$	24-hr	10.3[e]	23	33.3	35	95	---	---
	Annual	2.31[e]	7	9.31	15.0	62	---	---
NO_2	1-hr	240[b]	75	315	------	------	564	56
	Annual	2.0[c]	6	8.0	100	8.0	94	8.5
SO_2	1-hr	87.2	35	122	------	------	1,300	9.4
	3-hr	44.3	26	70.3	1,300	5.4	------	-----
	24-hr	7.8	11	18.8	365	5.2	262	7.2
	Annual	0.8	3	3.8	80	4.8	52	7.3
Pb	Quarterly[d]	0.0005	Not. Avail.	0.0005	1.5	0.03		
	90-day[d]	0.0005	Not. Avail.	0.0005	-----	-----	1.5	0.03

[a] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-6th-high.
[b] One-hour NOx impact is converted to NO_2 by applying the ozone limiting method, as per DEQ guidance.
[c] Annual NOx is converted to NO_2 by applying the ambient ratio method, as per DEQ guidance.
[d] SME reported the 24-hour average impact for compliance demonstration.
[e] PM_{10} modeling results are compared to $PM_{2.5}$ standards.

Cumulative impact modeling, including emissions from all PSD increment-consuming sources in the Great Falls area, was used to demonstrate compliance with the Class II PSD increments for PM_{10}, NO_x and SO_2. Class II increment modeling results are compared to the applicable PSD increments in Table 3.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. (μg/m³)	Class II Increment (μg/m³)	% Class II Increment Consumed	Peak Impact Location (UTM Zone 12)
PM_{10}	24-hr	Great Falls 1988	10.5	30	35%	(497701, 5266846)
	Annual	Great Falls 1987	3.2	17	19%	(497701, 5267036)
SO_2	3-hr	Great Falls 1999	12.6	512	2.5%	(497069, 5266071)
	24-hr	Great Falls 2003	6.33	91	6.9%	(497069, 5266071)
	Annual	Great Falls 1987	0.4	20	2.0%	(497386, 5268078)
NO_2	Annual[b]	Great Falls 1988	1.7	25	6.8%	(497386, 5268078)

a – Compliance with short-term standards is based on high-second-high impact.
b – Annual NO_x impacts are compared to the NO_2 standards.

SME-HGS submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the Class I areas within 250 km of the project site. CALMET was used to prepare meteorological data for input to CALPUFF. Meteorological data inputs to CALMET are included in Table 4.

Table 4: CALPUFF MET Data

Input Data Parameter	Model Year		
	1990	1992	1996
Number of Surface Stations	14	13	13
Number of Upper Air Stations	7	7	5
Number of Precipitation Stations	98	99	92
MM4/MM5 Data Grid Size	80 km	80 km	36 km

SME-HGS modeled PM_{10}, SO_2, and NO_x emissions from the SME-HGS project, and compared SME-HGS impacts to EPA's proposed Class I SIL's. SME-HGS's impacts exceeded the Class I SO_2 SILs at the Gates of the Mountain and Scapegoat Wilderness Areas. Modeling of PM_{10} and NO_x emissions did not show any exceedances of the Class I SILs at any of the Class I areas. Cumulative impact modeling for SO_2, including all PSD increment-consuming sources, was provided for the Class I areas. Results of the Class I cumulative impact modeling are included in Table 5 and show that the cumulative modeled concentrations are lower than the Class I PSD increments.

Table 5: Class I PSD Increment Compliance Demonstration, Peak Impacts

Pollutant	Avg. Period	Met Data Period	SME Modeled Conc. ($\mu g/m^3$)	Non-SME Modeled Conc. ($\mu g/m^3$)	Total Modeled Conc. ($\mu g/m^3$)	% Class I Increment Consumed
Gates of the Mountains						
SO_2	3-hr	July 23, 1996	1.08	1.26	2.34	9.4%
	24-hr	March 5, 1996	0.25	0.29	0.54	11%
Scapegoat Wilderness Area						
SO_2	24-hr	April 11, 1990	0.21	0.36	0.57	11%

a – Compliance with short-term standards is based on high-first-high impact.

SME-HGS used the CALPUFF modeling results and the CALPOST program to determine deposition values in the Class I areas. The results are shown in Table 6 and are compared to the deposition level of concern identified in the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). None of the modeled deposition impacts exceeded the FLAG level of concern. The Department concluded that no additional analysis of deposition impacts is needed.

Table 6: SME-HGS CALPUFF Deposition Modeling Results

Class I Area	1990		1992		1996	
	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)
Ana-Pintler	0.0003	0.0004	0.0001	0.0002	0.0002	0.0002
Bob Marsh.	0.001	0.001	0.001	0.001	0.001	0.001
Gates Mtns.	0.002	0.002	0.002	0.002	0.002	0.003
Glacier NP	0.0003	0.0003	0.0003	0.0003	0.001	0.001
Mission Mtns	0.0002	0.0003	0.0005	0.001	0.0004	0.001
Scapegoat	0.001	0.001	0.001	0.001	0.002	0.002
UL Bend	0.002	0.002	0.001	0.002	0.002	0.002
FLAG Level of Concern	0.005	0.005	0.005	0.005	0.005	0.005

SME-HGS provided an analysis of the impact of the proposed project on air quality related values (AQRV) in the Class I and Class II areas. The effects of deposition on sensitive plant species and the effects of trace elements deposition on soils, plants, and animals were found to be below guideline levels contained in the USEPA screening guideline (EPA 450/2-81-078). The Department and affected FLMs have concluded that lake acidification analyses were not necessary because there are no sensitive lakes in the project impact area.

A visibility impact assessment is required under ARM 17.8.825 and ARM 17.8.1103, which states that the visibility requirements are applicable to the owner or operator of a proposed major stationary source, as defined by ARM 17.8.802(22). ARM 17.8.1106(1) requires that "the owner or operator of a major stationary source "…demonstrate that the actual emissions (including fugitive emissions) will not cause or contribute to adverse impact on visibility within any federal Class I area or the Department shall not issue a permit."

SME-HGS provided a visibility impact assessment as required under ARM 17.8.825 and ARM 17.8.1103 using the CALPUFF/CALPOST modeling system. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a percent reduction in background extinction ($\%\Delta B_{ext}$). The results of SME-HGS's final visibility analysis are included in Table 7 and show 6 days in which the modeled $\%\Delta B_{ext}$ values from SME were ≥ 5%. Cumulative impact modeling was performed for those days to determine the $\%\Delta B_{ext}$ value from all the existing permitted PSD increment-consuming sources that could contribute to visibility reduction. The modeling showed four days with cumulative modeled $\%\Delta B_{ext}$ value greater than 10%.

Table 7: SME Final Visibility Results (Refined Methodology)

Class I Area	Met Data Year	Max. ΔB_{ext} 24-hr Average	Number of Days $\%\Delta B_{ext} \geq 5.0\%$	Peak Cumulative $\%\Delta B_{ext}$
Bob Marshall Wilderness Area	1990	1.57	0	NA
	1992	6.90	1	14.45
	1996	9.92	2	19.21
Gates of the Mountains Wilderness Area	1990	5.62	1	5.63
	1992	4.32	0	NA
	1996	5.77	1	15.05
Glacier National Park	1992	3.92	0	NA
	1996	1.21	0	NA
Scapegoat Wilderness Area	1990	2.31	0	NA
	1992	4.30	0	NA
	1996	5.31	1	13.65
UL Bend Wilderness Area	1992	2.09	0	NA
	1996	4.47	0	NA

The Department reviewed the visibility analysis and determined that the SME-HGS project alone and the cumulative impact of all permitted PSD increment-consuming sources will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does, or is likely to, interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within the affected federal Class I area. This determination takes into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

Conclusion

The preceding analysis represents a summary of predicted ambient air quality impacts resulting from the proposed SME-HGS project. A comprehensive and complete dispersion modeling analysis demonstrating compliance with all applicable increments and standards is on file with the Department. Based on this analysis, the Department determined that the proposed project operating in compliance with the applicable requirements contained in Permit #3423-00 is expected to maintain compliance with all applicable increments and standards as required for permit issuance.

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? (ex.: 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 pubic 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

The proposed SME-HGS project was subject to review under the requirements of the Montana Environmental Policy Act. A comprehensive Final Environmental Impact Statement (FEIS) was issued on February 9, 2007, and the Record of Decision on the FEIS was published on April 20, 2007 The scope of this permit action does not constitute a modification to the facility or its operation that results in potential environmental impacts not already considered in the April 20, 2007 FEIS. A copy of the FEIS is available from the Department upon request.

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Date: October 3, 2008