July 16, 2009

Mr. Dan Dunlap
Rocky Mountain Power, LLC
Hardin Generating Station
2575 Park Lane, Suite 200
Lafayette, CO 80026

Dear Mr. Dunlap:

Montana Air Quality Permit #3185-05 is deemed final as of July 16, 2009, by the Department of Environmental Quality (Department). This permit is for a Rocky Mountain Power, LLC – Hardin Generating Station coal fired steam electric generation plant. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Vickie Walsh

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

Paul Skubinna

Paul Skubinna
Environmental Engineer
Air Resources Management Bureau
(406) 444-6711

VW:PS
Enclosures

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #3185-05

Rocky Mountain Power, LLC – Hardin Generating Station
2575 Park Lane, Suite 200
Lafayette, CO 80026

July 16, 2009

MONTANA AIR QUALITY PERMIT

Issued To:	Rocky Mountain Power, LLC Hardin Generating Station 2575 Park Lane, Suite 200 Lafayette, CO 80026	Permit: #3185-05 Application Complete: 04/16/09 Preliminary Determination Issued: 05/26/09 Department's Decision Issued: 06/30/09 Permit Final: 07/16/09 AFS #: 003-0018

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Rocky Mountain Power, LLC (RMP), 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

RMP owns and operates a stationary facility that produces electrical power for delivery to the existing power grid. The facility is known as the Hardin Generating Station (HGS) and is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The facility consists of a pulverized coal-fired boiler (PC-Boiler) and a steam turbine, which drives a 135 MVA class nameplate electric generator to produce a nominal 116-gross megawatts (MW) of electric power (approximately 11-MW of the power produced is used for plant auxiliary power). A complete list of the permitted equipment for the coal-fired steam-electric generating station is contained in the permit analysis.

B. Current Permit Action

On December 22, 2008 and April 16, 2009, the Montana Department of Environmental Quality (Department) received application material from RMP proposing to modify MAQP #3185-04. The modification proposed to establish a mercury (Hg) emission limit for the HGS pursuant to ARM 17.8.771, and to provide an analysis of potential mercury control options including, but not limited to, boiler technology, mercury emission control technology, and any other mercury control practices. The application also included a proposed mercury emission control strategy. Additionally, RMP provided information relevant to, and requested that MAQP #3185-05 establish emission limitations and requirements satisfying, the Hardin Generating Station Settlement Agreement (Settlement Agreement) signed by the Montana Board of Environmental Review on May 6, 2005. The information provided described the results of the Hg Demonstration Period and Hg Optimization Period efforts required by the Settlement Agreement in order to establish a numeric Hg emission limitation based on performance of the Best Available Control Technology (BACT) derived Activated Carbon Injection (ACI) base technology controls, in conjunction with the control system optimization efforts. Optimization testing and analysis to establish the BACT limit included co-benefit testing analysis of coal blending and coal additives as well as testing and analysis of injection of multiple activated carbon based commercially available engineered Hg sorbents into the exhaust stream after the air heater. Finally, RMP provided an analysis of effects of operation of the mercury control system on the performance of the permitted sulfur dioxide (SO_2) and particulate matter/particulate matter with an aerodynamic diameter of 10 microns or less (PM/PM_{10}) emission control equipment.

MAQP #3185-05 establishes a BACT Hg emission limit based upon demonstrated performance during the Hg Optimization Period pursuant to the Settlement Agreement and an Hg emission limitation and associated operating requirements for the HGS in order to comply with ARM 17.8.771. Also, MAQP #3185-05 establishes the requirements for an Hg compliance monitoring plan pursuant to applicable rules and the Settlement Agreement. Finally, this permit action also updates rule references, permit format, and the emissions inventory.

SECTION II: Conditions and Limitations

A. General Plant Requirements

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

2. RMP 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).

3. RMP shall treat all unpaved portions of the access roads, parking lots, and general plant area with chemical dust suppressant and/or clear, non-oily water which does not contain regulated hazardous waste as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.749).

4. The annual heat input to the PC-Boiler shall not exceed 11,423,040 million British thermal units (MMBtu) per rolling 12-month time period (ARM 17.8.749).

5. RMP 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. RMP 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).

B. PC-Boiler Startup and Shutdown, and SDA Atomizer Change-Out Operations

1. PC-Boiler startup and shutdown, and SDA atomizer change-out operations shall be conducted as described in the *PC-Boiler Start-Up and Shutdown, and SDA atomizer change-out Procedures* included in Attachment 3 or according to another PC-Boiler startup and shutdown, and SDA atomizer change-out plan as may be approved by the Department in writing (ARM 17.8.749).

2. PC-Boiler startup and shutdown, and SDA atomizer replacement operations, as defined in Section II.B.3, shall not exceed the 182.6 lb/hr SO_2 emission limit contained is Section II.C.4 more than 6 hours during any rolling 24-hour time period (ARM 17.8.749 and ARM 17.8.752).

3. For MAQP conditions that refer to PC-Boiler startup and shutdown, and SDA atomizer change-outs, the following conditions apply (ARM 17.8.749):

a. PC-Boiler startup periods begin when coal flow is detected in the PC-Boiler by the data acquisition and handling system (DAHS) and end when gross generator output is equal to 79 gross MW.
b. PC-Boiler shutdown periods begin when gross generator output is less than 79 gross MW and end when coal flow is no longer detected in the PC-Boiler by the DAHS.

c. If a PC-Boiler shutdown procedure is aborted, the PC-Boiler is in startup until the gross generator output is equal to 79 gross MW.

d. SDA atomizer change-out periods begin when operation of the SDA is suspended for the purpose of replacing an atomizer and end when operation of the SDA is resumed after replacing an atomizer.

4. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3, SO_2, hydrochloric acid (HCl), hydrofluoric acid (HF), and sulfuric acid (H_2SO_4) mist emissions from the PC-Boiler stack shall be controlled by implementing proper work practices (ARM 17.8.752).

5. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3, SO_2 emissions from the PC-Boiler stack shall not exceed 1465 lb/hr based on a 1-hour average (ARM 17.8.752).

6. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3, SO_2 emissions from the PC-Boiler stack shall not exceed 990 lb/hr based on a 3-hour rolling average (ARM 17.8.749).

C. PC-Boiler

1. Carbon Monoxide (CO) emissions from the PC-Boiler shall be controlled by proper design and combustion. CO emissions from the PC-Boiler stack shall not exceed 0.15 lb/MMBtu (ARM 17.8.752).

2. Oxides of nitrogen (NO_x) emissions from the PC-Boiler shall be controlled by selective catalytic reduction (SCR). NO_x emissions from the PC-Boiler stack shall not exceed 0.09 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752).

3. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, SO_2 emissions from the PC-Boiler shall be controlled with the use of a dry flue gas desulfurization (FGD) system, specifically characterized as an SDA (ARM 17.8.752).

4. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, SO_2 emissions from the PC-Boiler stack shall not exceed 182.6 lb/hr based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752).

5. SO_2 emissions from the PC-Boiler stack shall not exceed 0.11 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752).

6. The control efficiency for the SO_2 emission control equipment shall be maintained at a minimum of 90% based on a 30-day rolling average (as measured according to 40 CFR 60.49Da(b) (ARM 17.8.752).

7. PM/PM_{10} emissions from the PC-Boiler shall be controlled with the use of a fabric filter baghouse (FFB) while coal is being combusted in the PC-Boiler (ARM 17.8.752).

8. PM/PM_{10} emissions from the PC-Boiler stack shall not exceed 0.012 lb/MMBtu (filterable) (ARM 17.8.752).

9. PM/PM_{10} emissions from the PC-Boiler stack shall not exceed 0.024 lb/MMBtu (filterable and condensable) (ARM 17.8.752).

10. Volatile Organic Compounds (VOC) emissions from the PC-Boiler shall be controlled by good combustion practices. VOC emissions from the PC-Boiler stack shall not exceed 0.0034 lb/MMBtu (ARM 17.8.752).

11. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, HCl emissions from the PC-Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, HCl emissions from the PC-Boiler stack shall not exceed 1.54 lb/hr (0.00118 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

12. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, HF emissions from the PC-Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, HF emissions from the PC-Boiler stack shall not exceed 0.67 lb/hr (0.00051 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

13. Except during periods of startup, shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, H_2SO_4 mist emissions from the PC-Boiler shall be controlled by the use of dry FGD/SDA. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3, H_2SO_4 emissions shall not exceed 8.2 lb/hr (0.0063 lb/MMBtu) based on a 1-hour average (ARM 17.8.752).

14. The emissions of radionuclides from the PC-Boiler shall be controlled by an FFB. The PC-Boiler's PM_{10} emission limits shall be used as surrogate emission limits for radionuclides (ARM 17.8.752).

15. The emissions of trace metals from the PC-Boiler shall be controlled by an FFB. The PC-Boiler's PM_{10} emission limits shall be used as surrogate emission limits for trace metals (ARM 17.8.752).

16. The PC-Boiler stack shall stand no less than 250 feet above ground level (ARM 17.8.749).

17. The sulfur content of any coal fired at RMP shall not exceed 1% by weight calculated on a monthly average (ARM 17.8.749).

18. Coal fired in the PC-Boiler shall have a minimum heating value of 8000 Btu/lb calculated on a monthly average (ARM 17.8.749).

19. Beginning January 1, 2010, RMP shall limit Hg emissions from the PC Boiler to an emission rate equal to or less than 0.9 pounds Hg per trillion British thermal units (lb/TBtu), calculated as a rolling 12-month average (ARM 17.8.771 and ARM 17.8.752).

20. RMP shall install a sorbent/activated carbon injection (ACI) system. RMP shall implement the operation and maintenance of the ACI systems on or before January 1, 2010 (ARM 17.8.771 and ARM 17.8.752).

21. RMP shall comply with all applicable standards and limitations, and the applicable operating, reporting, recordkeeping, and notification requirements contained in 40 CFR Part 75 (ARM 17.8.771).

D. Cooling Tower

RMP is required to operate and maintain a mist eliminator on the cooling tower that limits PM_{10} emissions to no more than 0.001% of circulating water flow (ARM 17.8.752).

E. Coal Transfer, Coal Milling, Fuel Transfer, Lime Transfer, and Bottom and Fly Ash Transfer

1. Emissions from the following baghouses/bin vents shall not exceed 0.01 grains per dry standard cubic foot (grains/dscf) of particulate emissions (ARM 17.8.752):

   a. Coal unloading baghouse: RCF-BH-001
   b. Coal silo baghouse: RCF-BH-002
   c. Coal storage bunkers baghouse: RCF-BH-003
   d. SDA lime silo bin vent: FGT-BV-001
   e. FGD ash silo bin vent: WMH-BV-002
   f. Recycle ash silo bin vent: FGT-BV-002
   g. Water treatment lime silo baghouse: RWS-BH-001
   h. Soda ash silo baghouse: RWS-BH-002

2. RMP shall install and maintain enclosures surrounding the following process operations (ARM 17.8.752):

   a. Coal Transfer:

      i. Truck to below-grade hopper
      ii. Below-grade hopper to stockout conveyor
      iii. Coal storage silo to reclaim conveyor
      iv. Reclaim conveyor to bunker feed conveyor
      v. Bunker feed conveyor to coal bunkers
      vi. Coal bunkers to coal pulverizers

   b. Coal Pulverizers

   c. Fuel Transfer: Coal pulverizers to PC-Boiler

3. Draft pressure from the PC-Boiler shall be present to provide particulate control for fuel transfer from coal pulverizers to the PC-Boiler (ARM 17.8.752).

4. RMP shall store onsite coal in the coal storage silo (ARM 17.8.749).

5. RMP shall operate and maintain the activated carbon injection/sorbent handling systems, including the bin vent filter systems, to provide the maximum air pollution control for that which the systems were designed (ARM 17.8.752).

F. Temporary Auxiliary Boiler

1. The operation of the temporary auxiliary boiler shall not exceed 1000 hours per rolling 12-month time period (ARM 17.8.749).

2. The sulfur content of the No. 2 fuel oil used in the temporary auxiliary boiler shall not exceed 0.05% sulfur (ARM 17.8.752).

3. RMP shall not operate the temporary auxiliary boiler while the PC-Boiler is combusting coal (ARM 17.8.749).

G. Testing Requirements

1. RMP shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the opacity limit contained in Section II.A.1, for the PC-Boiler (ARM 17.8.749).

2. RMP shall test the PC-Boiler for CO to monitor compliance with the CO emission limit contained in Section II.C.1 on an every 2-year basis from the initial source test date, or according to another testing/monitoring schedule/demonstration as may be approved by the Department (ARM 17.8.105 and 17.8.749).

3. RMP shall use the data from the NO_x Continuous Emission Monitoring System (CEMS) to monitor compliance with the NO_x emission limits contained in Section II.C.2, for the PC-Boiler (ARM 17.8.749).

4. RMP shall use the data from the SO_2 CEMS to monitor compliance with the SO_2 emission limits contained in Sections II.B.5, II.B.6, II.C.4, II.C.5, and II.C.6, for the PC-Boiler (ARM 17.8.749).

5. RMP shall test the PC-Boiler for PM/PM_{10} to monitor compliance with the PM/PM_{10} emission limits contained in Sections II.C.8 and II.C.9 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

6. RMP shall test the PC-Boiler for HCl to monitor compliance with the HCl emission limit contained in Section II.C.11 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

7. RMP shall test the PC-Boiler for HF to monitor compliance with the HF emission limit contained in Section II.C.12 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

8. RMP shall test the PC-Boiler for H_2SO_4 to monitor compliance with the H_2SO_4 limit contained in Section II.C.13 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

9. RMP shall obtain written coal analyses that are representative for all coal received from each coal supplier. A daily sample (or samples, if necessary, with amounts used of each type, as appropriate) representing all coal received for that day shall be analyzed for, at a minimum, sulfur content, ash content, and Btu value (Btu/lb). A monthly composite sample representing all coal received during the month will be analyzed for, at a minimum, mercury, chlorine, and fluorine content (ARM 17.8.749).

10. Compliance with Section II.C.19, where applicable, shall be determined by utilizing data taken from a Mercury Emission Monitoring System (MEMS) in conjunction with the relative accuracy test audit (RATA) requirements included in Attachment 4 via Section II.I.f. The MEMS shall be comprised of equipment as required in 40 CFR 75.81(a) and defined in 40 CFR 72.2. The above does not relieve RMP from meeting any applicable requirements of 40 CFR Part 75 (ARM 17.8.771).

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

12. The Department may require additional testing (ARM 17.8.105).

H. Operational Reporting Requirements

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

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

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

3. RMP shall document, by month, the total heat input for the PC-Boiler. Within 30 days following the end of each month, RMP shall calculate the total heat input for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.A.4. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

4. RMP shall document, by month, the hours of operation of the temporary auxiliary boiler. Within 30 days following the end of the month, RMP shall calculate the total hours of operation for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.F.2. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

5. RMP shall document, by day, date, and time, all hours that the PC-Boiler is in startup and shutdown, as defined in Section II.B.3, and all hours that the SDA is in atomizer change-out, as defined in Section II.B.3. Each day, RMP shall sum the hours that the PC-Boiler is in startup and shutdown, as defined in Section II.B.3, and the hours that the SDA is in atomizer change-out, as defined in Section II.B.3, for the rolling 24-hour time periods of the previous day. The information will be used to verify compliance with the rolling 24-hour limitation in Section II.B.2. The information for each rolling 24-hour time period shall be submitted along with the annual emission inventory. The information for each rolling 24-hour time period shall also be submitted along with any quarterly SO_2 excess emission report but only the rolling 24-hour time periods within the applicable quarter need be submitted (ARM 17.8.749)

6. The owner or operator of any mercury-emitting generating unit shall report to the Department within 30 days after the end of each calendar quarter, as described in Attachment 4 (ARM 17.8.749):

   a. The monthly average lb/TBtu mercury emission rate, for each month of the quarter;

   b. The 12-month rolling average lb/TBtu emission rate for each month of the reporting quarter; and

   c. Number of operating hours that the MEMS was unavailable or not operating within quality assurance limits (monitor downtime).

7. The first quarterly report must be received by the Department by April 30, 2010, but shall not include 12-month rolling averages. The first quarterly report to include 12-month rolling averages must be received by the Department by January 30, 2011 (ARM 17.8.749).

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

I. Continuous Emission Monitoring Systems

1. RMP shall install, operate, calibrate, and maintain CEMS for the following:

   a. A CEMS for the measurement of SO_2 shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on the PC-Boiler stack (40 CFR Parts 72-78).

   c. A CEMS for the measurement of NO_x shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   d. A COMS for the measurement of opacity shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on the PC-Boiler stack (ARM 17.8.749).

f. A MEMS shall be installed, certified, and operating on the boiler stack outlet on or before January 1, 2010. Said monitor shall comply with the applicable provisions of 40 CFR Part 75. The monitors shall also conform to the requirements included in Attachment 4 (ARM 17.8.771).

2. RMP shall determine CO_2 emissions from the PC-Boiler stack by one of the methods listed in 40 CFR 75.10 (40 CFR Parts 72-78).

3. All continuous monitors required by this MAQP and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR 60, Subpart A; 40 CFR 60, Subpart Da; 40 CFR 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Parts 72-78, as applicable (ARM 17.8.749 and 40 CFR Parts 72-78).

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

5. RMP shall inspect and audit the COMS annually, using neutral density filters. RMP 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 as described in Attachment 2 to this MAQP (ARM 17.8.749).

6. RMP 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 file shall be retained on site for at least 5 years following the date of such measurements and reports. RMP shall supply these records to the Department upon request (ARM 17.8.749).

7. RMP 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 file shall be retained on site for at least 5 years following the date of such measurements and reports. RMP shall supply these records to the Department upon request (ARM 17.8.749).

SECTION III: General Conditions

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

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

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

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

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 an MAQP 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 MAQP 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, as amended by the 1991 Legislature, failure to pay the annual operation fee by RMP may be grounds for revocation of this MAQP, as required by that section and rules adopted thereunder by the Board.

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

Attachment 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, SDA atomizer change-outs, 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	Time 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 [2]**
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

PC-Boiler Start-Up, Shutdown, and SDA Atomizer Change-Out Procedures
MAQP #3185-05

PC-Boiler startup and shutdown, and SDA atomizer change-out operations shall be conducted as described in this attachment.

I. PC-Boiler Startup Operations

The PC-Boiler/generator system must be started gradually to allow system components to equilibrate and to avoid excessive thermal stresses on mechanical components. The amount of time required to complete a startup procedure will vary depending upon a variety of factors; however, typical procedures require less than 16 hours. RMP proposed a combined PC-Boiler Startup and shutdown and SDA atomizer change-out limit of no more than 6 hours per rolling 24-hour average while coal is being combusted in the PC-Boiler. During the startup process, the PC-Boiler steps through a series of changes to reach full load firing on coal. During this process, SO_2, HCl, HF, H_2SO_4 mist, PM/PM_{10}, radionuclides, trace metals, and NO_x emissions may vary until air pollution control equipment can be operated at a minimum continuous load on the PC-Boiler. The startup procedures are as follows:

1. Natural gas igniters are placed in service to preheat the PC-Boiler and boil out the superheater pendants. The time required to complete this step depends on the initial temperature of the PC-Boiler.

   - A cold boiler must fire for approximately 8 hours.
   - A warm boiler must fire for approximately 5 hours.
   - A hot boiler must fire for approximately 2 hours.

2. Once the superheater pendants are boiled out, the steam pressure and temperature are increased to the steam quality required to roll the steam turbine.

3. The steam turbine is then rolled up to 1,000 revolutions per minute (RPM) and held until the turbine is at the required metal temperatures.

4. The turbine can then roll up to sync speed (3,600 RPM).

5. Once at sync speed and with vibration indicators in the normal range, the turbine is placed online and the plant load increased to 7 MWs.

6. Plant load (plant output) for the next hour must be scheduled with a PowerEx dispatcher before continuing with the startup procedure.

7. The FFB can then be placed in service. In order to complete this step:

   - All 12 igniters must be firing on gas; and
   - The stack temperature must be above 175 degrees Fahrenheit.
   - The FFB logic then puts two compartments in service and monitors the stack temperature. During cooler weather the stack temperature will drop 10 to 15 degrees Fahrenheit each time a set of compartments is placed in service. It then takes approximately 20 minutes for the stack temperature to return to the 175 degree set point, at which time the next set of two compartments is placed in service.
   - Because there are six compartments, it takes approximately 40 to 50 minutes to get the FFB completely in service.

8. The first pulverizer can now be started and plant load increases up to approximately 40 MWs. Coal flow to the PC-Boiler is detected by the DAHS.

9. Plant load is scheduled at minimum load (79 MWs) with Power Ex dispatcher for approximately 1 hour.

10. Control systems are placed in auto and allowed to settle out. This step takes approximately 30 to 45 minutes to complete.

11. The second pulverizer is then started and plant load increases to the scheduled minimum load. Coal flow to the PC-Boiler is detected by the DAHS.

12. At this time the SCR and SDA can be placed in service.

    - The SCR average temperature must be at 590 degrees Fahrenheit between the inlet and outlet of the SCR. This minimum temperature can only be achieved when the plant is at or above 79 MWs.
    - The SDA inlet temperature must be between 250 and 300 degrees Fahrenheit before the atomizer can be placed in service (start spraying slurry).
        - If the SDA inlet temperature is not at setpoint, then outlet temperature will drop below 169 degrees Fahrenheit and the SDA spray valves will close, shutting down the atomizer.
        - This temperature setpoint is in place to protect the FFB from getting coated with wet fly ash and plugging the bags.

As soon as the plant is at minimum load (79 MWs) and all the air pollution control equipment is in service, the startup process is complete. At this time the unit can be loaded to the desired output.

II. <u>PC-Boiler Shutdown Operations</u>

The shutdown procedures are as follows:

1. The slide gate is closed on Coal Feeder C as load is decreased to approximately 92 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. Simultaneously, the lime/recycle ash flow to SDA is reduced as needed to maintain an SDA outlet temperature of between 172 and 175 degrees Fahrenheit.

2. The slide gate is closed on Coal Feeder B as load is decreased below 79 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. SDA lime/recycle ash flow is ramped down to zero flow while maintaining a baghouse inlet temperature of at least 169 degrees Fahrenheit, SCR ammonia injection is turned off.

3. The slide gate is closed on Coal Feeder A as load is decreased below 79 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. Simultaneously, natural gas is fired to stabilize the system.

4. When load reaches 10 MW, the gas flow to the PC-Boiler is turned off. The steam turbine is taken off line, the stop valve is closed, and when the turbine has stopped turning, the turbine is put on the turning gear.

Note: If the plant is going to be down for a short period of time, the slide gates are left open and the feeder is shut off, and the cal mill is ran until it is empty.

III. SDA Atomizer Change-Out Operations

Unscheduled Change-out

When lime slurry flow reductions are observed (approximately 30 – 40 gallons per minute), PC-Boiler SO_2 emissions increase, or an increase control valve opening indicates atomizer plugging, the in-service atomizer will be replaced with the standby atomizer. The removed atomizer wheel is cleaned and placed in ready standby position.

Scheduled Change-Out

Routine atomizer maintenance is scheduled no longer than 10 days after the last atomizer change-out. In that case, the in-service atomizer is removed and replaced with the standby atomizer. The removed atomizer wheel is cleaned and placed in ready standby position.

Atomizer Change-Out Process

1. The slurry flow, SO_2 emissions, and control valve position are noted.

2. Prior to removing the atomizer from service, scrubbing is increased if possible to build a thick cake on the fabric filter bags.

3. The slurry flow and the atomizer motor are secured.

4. The atomizer is removed from the in-service position.

5. The stand-by atomizer is installed.

6. The atomizer is started and the status of the slurry flow, SO_2 emissions, and control valve position is verified to ensure they have returned to normal.

Under each scenario, atomizer change-out should require no more than 30-45 minutes except that one to one and one-half hours may be required if no standby atomizer motor is available.

Attachment 4

MEMS

a. RMP shall install, calibrate, certify, maintain, and operate an MEMS to monitor and record the rate of mercury emissions discharged into the atmosphere from all mercury emitting generating units (units) as defined in the Administrative Rules of Montana 17.8.740.

  (1) The MEMS shall be comprised of equipment as required in 40 CFR 75.81(a) and defined in 40 CFR 72.2.

  (2) The MEMS shall conform to all applicable requirements of 40 CFR Part 75.

  (3) The MEMS data will be used to demonstrate compliance with the emission limitations contained in Section II.C.19.

b. RMP shall prepare, maintain and submit a written MEMS Monitoring Plan to the Department.

  (1) The monitoring plan shall contain sufficient information on the MEMS and the use of data derived from these systems to demonstrate that all the gaseous mercury stack emissions from each unit are monitored and reported.

  (2) Whenever RMP makes a replacement, modification, or change in a MEMS or alternative monitoring system under 40 CFR 75 subpart E, including a change in the automated data acquisition and handling system (DAHS) or in the flue gas handling system, that affects information reported in the monitoring plan (e.g. a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

  (3) If any monitoring plan information requires an update pursuant to Section b.(2), submission of the written monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly report required in c. below for the quarter in which the update is required.

  (4) The initial submission of the Monitoring Plan to the Department shall include a copy of a written Quality Assurance/Quality Control (QA/QC) Plan as detailed in 40 CFR 75 Appendix B, Section 1. Subsequently, the QA/QC Plan need only be submitted to the Department when it is substantially revised. Substantial revisions can include items such as changes in QA/QC processes resulting from rule changes, modifications in the frequency or timing of QA/QC procedures, or the addition/deletion of equipment or procedures.

  (5) The Monitoring Plan shall include, at a minimum, the following information:

    (a) Facility summary including:

      (i) A description of each mercury emitting generating unit at the facility.

      (ii) Maximum and average loads (in MW) with fuels combusted and fuel flow rates at the maximum and average loads for each unit.

      (iii) A description of each unit's air pollution control equipment and a description of the physical characteristics of each unit's stack.

    (b) Mercury emission control summary including a description of control strategies, equipment, and design process rates.

(c) MEMS description, including:

(i) Identification and description of each monitoring component in the MEMS including manufacturer and model identifications; monitoring method descriptions; and normal operating scale and units descriptions. Descriptions of stack flow, diluent gas, and moisture monitors (if used) in the system must be described in addition to the mercury monitor or monitors.

(ii) A description of the normal operating process for each monitor including a description of all QA/QC checks.

(iii) A description of the methods that will be employed to verify and maintain the accuracy and precision of the MEMS calibration equipment.

(iv) Identification and description of the DAHS, including major hardware and software components, conversion formulas, constants, factors, averaging processes, and missing data substitution procedures.

(v) A description of all initial certification and ongoing recertification tests and frequencies; as well as, all accuracy auditing tests and frequencies.

(d) The Maximum Potential Concentration (MPC), Maximum Expected Concentration (MEC), span value, and range value as applicable and as defined in 40 CFR 75 Appendix A, 2.1.7.

(e) Examples of all data reports required in c. below.

c. RMP shall submit written, Quarterly Mercury Monitoring Reports. The reports shall be received by the Department within 30 days following the end of each calendar quarter, and shall include, at a minimum, the following:

(1) Mercury emissions. The reports shall include:

(a) The monthly average lb/TBtu mercury emission rate for each month of the quarter;

(b) The 12-month rolling average lb/TBtu emission rate for each month of the reporting quarter. The rolling 12-month basis is an average of the last 12 individual calendar monthly averages, with each monthly average calculated at the end of each calendar month; and

(c) The total heat input to the boiler (in TBtu) for each 12-month rolling period of the quarter.

(2) Mercury excess emissions. The report shall describe the magnitude of excess mercury emissions experienced during the quarter, including:

(a) The date and time of commencement and completion of each period of excess emissions. Periods of excess emissions shall be defined as those emissions calculated on a rolling 12-month basis which are greater than the limitation established in II.C.19.

(b) The nature and cause of each period of excess emissions and the corrective action taken or preventative measures adopted in response.

(c) If no periods of excess mercury emissions were experienced during the quarter, the report shall state that information.

(3) MEMS performance. The report shall describe:

(a) The number of operating hours that the MEMS was unavailable or not operating within quality assurance limits (monitor downtime) during the reporting quarter, broken down by the following categories:

- Monitor equipment malfunctions;
- Non-Monitor equipment malfunctions;
- Quality assurance calibration;
- Other known causes; and
- Unknown causes.

(b) The percentage of unit operating time that the MEMS was unavailable or not operating within quality assurance limits (monitor downtime) during the reporting quarter. The percentage of monitor downtime in each calendar quarter shall be calculated according to the following formula:

$$MEMSDowntime\% = \left(\frac{MEMSDownHours}{OpHours} \right) \times 100 \quad \text{where}$$

MEMSDowntime%	=	Percentage of unit operating hours classified as MEMS monitor downtime during the reporting quarter.
MEMSDownHours	=	Total number of hours of MEMS monitor downtime during the reporting quarter.
OpHours	=	Total number of hours the unit operated during the reporting quarter.

(c) For any reporting quarter in which monitor downtime exceeds 10%, a description of each time period during which the MEMS was inoperative or operating in a manner defined in 40 CFR Part 75 as "out of control." Each description must include the date, start and end times, total downtime (in hours), the reason for the system downtime, and any necessary corrective actions that were taken. In addition, the report shall describe the values used for any periods when missing data substitution was necessary as detailed in 40 CFR 75.30, *et seq*.

(4) The quarterly report shall include the results of any QA/QC audits, checks, or tests conducted to satisfy the requirements of 40 CFR Part 75 Appendices A, B or K.

(5) Compliance certification. Each quarterly report shall contain a certification statement signed by the facility's responsible official based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate:

(a) Whether the monitoring data submitted were recorded in accordance with the applicable requirements of 40 CFR Part 75 including the QA/QC procedures and specifications of that part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method as represented in the approved Monitoring Plan.

(b) That for all hours where data are substituted in accordance with 40 CFR 75.38, the add-on mercury emission controls were operating within the range of parameters listed in the quality-assurance plan for the unit, and that the substitute values do not systematically underestimate mercury emissions.

(6) The format of each component of the quarterly report may be negotiated with the Department's representative to accommodate the capabilities and formats of the facility's DAHS.

(7) Each quarterly report must be received by the Department within 30 days following the end of each calendar reporting period (January-March, April-June, July-September, and October-December).

(8) The electronic data reporting detailed in 40 CFR Part 75 shall not be required unless Montana is able to receive and process data in an electronic format.

d. RMP shall maintain a file of all measurements and performance testing results from the MEMS; all MEMS performance evaluations; all MEMS or monitoring device calibration checks and audits; and records of all adjustments and maintenance performed on these systems or devices recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements and reports. RMP shall make these records available for inspection by the Department and shall supply these records to the Department upon request.

Permit Analysis
Rocky Mountain Power, LLC
MAQP #3185-05

I. Introduction/Process Description

A. Permitted Equipment

Rocky Mountain Power, LLC (RMP) owns and operates a nominal 116-gross megawatt (MW) electrical power generation facility approximately 1.2 miles northeast of Hardin, Montana. The facility consists of a pulverized coal-fired boiler (PC-Boiler) and a steam turbine, which drives a 135 MVA class nameplate electric generator to produce a nominal 116-gross MW of electric power (approximately 11-MW of the power produced is used by RMP for plant auxiliary power). The legal description of the site location is the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The following equipment is permitted for this facility:

1. 1,304 million British thermal units per hour (MMBtu/hr) PC-Boiler (with associated steam turbine and electric generator) with a 250-foot stack
2. Cooling tower
3. Coal, lime, ash and activated carbon injection/sorbent handling systems:

   a. Coal unloading baghouse (RCF-BH-001) – 50,000 dry standard cubic feet per minute (dscfm)
   b. Coal silo baghouse (RCF-BH-002) – 7,500 dscfm
   c. Coal storage bunkers baghouse (RCF-BH-003) – 5,000 dscfm
   d. Spray dry absorber (SDA) lime silo bin vent (FGT-BV-001) – 1,000 dscfm
   e. Flue gas desulfurization (FGD) ash silo bin vent (WMH-BV-002) – 2,000 dscfm
   f. Recycle ash silo bin vent (FGT-BV-002) – 2,000 dscfm
   g. Water treatment lime silo baghouse (RWS-BH-001) – 1,000 dscfm
   h. Soda ash silo baghouse (RWS-BH-002) – 1,000 dscfm
   i. Activated carbon silo bin vent (ACI-BV-001) – 90 pounds per hour (lb/hr) sorbent throughput

4. Temporary auxiliary boiler

B. Source Description

1. PC-Boiler and Associated Emission Control

The permitted PC-Boiler is a 1968 wet-bottom, wall-fired boiler manufactured by Mitchell of the United Kingdom. The PC-Boiler is configured with 3 pulverizers and 12 burners with opposed firing. The maximum nominal heat input rate to the PC-Boiler is 1,304 MMBtu/hr, which will be used to produce up to approximately 900,000 pounds of steam per hour. Natural gas is used to initially fire the PC-Boiler during periods of startup and pulverized coal is introduced during the later stages of startup (see attachment 3 of Montana Air Quality Permit (MAQP)). During normal operations, the PC-Boiler will be fueled with pulverized coal. The PC-Boiler combusts coal owned by the Tribe of Crow Indians from the Absaloka Mine. The mine, which is owned by Westmoreland Resources, Inc., is located approximately 30 miles east of Hardin.

PC-Boiler combustion gases (flue gases) are routed to a Selective Catalytic Reduction (SCR) unit for control of nitrogen oxides (NO_X). From the SCR unit, the flue gas is routed to a dry flue gas desulfurization (FGD) system (specifically characterized as a Spray Dry Absorber (SDA)) that uses a lime reagent for control of sulfur dioxide (SO_2) emissions.

Other acid gases including sulfuric acid (H_2SO_4) mist, hydrochloric acid (HCl) and hydrofluoric acid (HF). There are periods of time (i.e., PC-Boiler Startup and Shutdown and SDA atomizer change-outs) that the SDA can not be operated because a minimum flue gas temperature is required for the control equipment to operate, which is achieved at approximately 79 MW of load. Mercury (Hg) is controlled by injection of activated carbon/sorbent into the flue gas after the air heater. Mercury is oxidized, sorbed to the injectate, and finally removed from the flue gas by the fabric filter baghouse. The fabric filter baghouse (FFB) is located downstream of the SDA for particulate matter/particulate matter with an aerodynamic diameter of 10 microns or less (PM/PM_{10}) control. Additional pollutants such as Hg, trace metals, and radionuclides are also removed as a co-benefit control if present in the particulate form. From the FFB, the flue gas exits to the atmosphere.

2. Cooling Tower

A wet cooling tower is used to dissipate the heat from the steam turbine 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 is an induced, counter flow draft design equipped with cellular (honeycomb) drift eliminators. The maximum make-up water rate for the cooling tower is approximately 1,400 gallons per minute (gpm). Water will come from the Bighorn River. There will be no direct discharge to the waters of the state from the operation of the cooling tower. Blow-down is treated to maximize water recovery. Treatment includes a reverse osmosis unit followed by a condensate polisher (de-ionizer) and a small dehydrator. Discharge from the blow-down is reduced to less than 30 gpm, and is discharged to the makeup system for the lime slurry, which is injected into the SDA. If the discharged water cannot be immediately used, it is stored in a surge tank until it can be reused within the system.

3. Coal Storage and Handling

According to Westmoreland Resources, Inc., the coal will have an “as-received” moisture content of 24.5%. This high moisture content will serve to inhibit fugitive dust emissions during storage and handling activities. Coal is transported the 30 miles from the Absaloka Mine using over-the-road tractor-trailer transport vehicles. Coal is delivered around the clock at the rate of approximately 1-½ trucks per hour (3 trucks every 2 hours). Some of the empty coal trucks may be used to haul ash and/or scrubber sludge to the dedicated disposal site.

Coal delivery trucks deliver coal to an enclosed truck unloading station. The enclosure is a self-supported, metal-clad building with gravity louvers on the sidewalls and automated doors at the entry and exit ends for maximum containment of airborne PM. The building is of sufficient size to fully contain a delivery truck and trailer while the pup remains outside of the building. Gravity-operated louvers on the enclosure walls normally provide openings for the design volume of airflow removed by a dust collection system provided for the building. When one of the enclosure doors is opened, the dampers close, and air is drawn through the door openings only. The overhead doors are interlocked such that only one door can be open at a time.

The trucks unload coal into below-grade receiving hoppers sized to accept the complete discharge from a trailer and pup. A grizzly with 5-inch square openings is provided on the hopper to prevent oversize materials from entering and plugging the conveying equipment. A rubber seal boot partially encloses the grizzly and hopper top to minimize fugitive dust emissions during the unloading process. Two variable speed unloading feeders transfer coal from the unloading hoppers onto an inclined and enclosed belt transfer conveyor.

Fugitive dust collection for coal truck unloading operations is provided by a dust collector (RCF-BH-001) with a required efficiency of 0.01 grains per dry standard cubic foot (gr/dscf) and a fan that provides a nominal air flow rate of 50,000 actual cubic feet per minute (acfm). Coal dust collected by the baghouse is pneumatically conveyed to a coal storage silo. Ductwork connects the dust collector to the building enclosure, hopper rubber seal boot, and feeder transfer point hoods. Inflow air through the enclosure louvers or doors maintain a clean work environment within the enclosure. Inflow air through the hopper facilitates fugitive emissions collection during coal unloading. Additional ventilation is provided at the conveyor transfer points. Ventilation design will provide for positive ventilation (negative draft) of the building under worst-case conditions with one door fully open.

The stockout conveyor conveys coal from the receiving hoppers to the top of an active coal storage silo. The silo discharges at the bottom via a reclaim feeder to a covered belt conveyor. The reclaim conveyor transfers coal from the silo to coal bunkers located within the generation building. A fabric filter bin vent (RCF-BV-002) located on top of the silo controls dust emissions from silo loading with a maximum design outlet grain loading of 0.01 gr/dscf and 7,500 acfm air flow. It will also control fugitive dust emissions from material transfers between the reclaim feeder and reclaim conveyor. Dust pulsed from the bin vent fabric filters falls directly into the reclaim conveyor.

4. Lime Handling Operations

As previously mentioned, the facility uses a lime SDA to control SO_2 and certain Hazardous Air Pollutant (HAP) emissions. Lime is delivered by truck at a rate of approximately 1 truck per day. Lime is used at a rate of 2,200 pounds per hour (lb/hr).

Pebble lime for the SDA is pneumatically unloaded from delivery trucks into a storage silo. The storage silo is equipped with a fabric filter bin vent (FGT-BV-001) to collect fugitive dust generated during loading. The bin vent is limited to a maximum outlet grain loading of 0.01 gr/dscf (with a nominal airflow rate of 1,000 acfm). The bottom of the lime storage silo is enclosed and houses the lime screw feeder, slaker equipment, screw equipment, screw conveyor, and agitated slurry storage tank.

5. Ash and Spent Lime Handling Operations

Combustion of coal in the PC-Boiler produces ash. Bottom ash from the PC-Boiler and ash collected from the economizer is mixed with water and fed via a system of conveyors to a load-out bunker located outside of the generation building. Front-end loaders transfer the wetted material to trucks for transport off-site. Particulate emissions from these operations to the atmosphere are negligible since the materials are wet. A pneumatic conveying system collects fly ash and spent lime from the SDA and PC-Boiler baghouse. It transfers the material to one of two storage silos. SDA material feeds to an FGD ash silo. Material from the baghouse is first directed to a recycle ash silo. Once this silo is filled, the material is routed to the FGD ash silo.

Particulate emissions resulting from loading the recycle ash silo are controlled by a fabric filter bin vent located on top of the silo. The bin vent (WMH-BV-002) is limited to a maximum outlet grain loading of 0.01 gr/dscf (with a nominal airflow rate of 2,000 acfm). Material collected in the recycle ash silo is mixed with cooling tower blowdown water or raw water and used to feed the SDA.

Material not required for recycle is conveyed to the FGD ash silo. Particulate emissions resulting from silo loading are controlled by a fabric filter bin vent located on top of the silo. The bin vent (WMH-BV-003) is limited to a maximum outlet grain loading of 0.01 gr/dscf, (with a nominal airflow rate of 2,000 acfm). Material is discharged from the silo to a screw feeder for either wet or dry loadout into trucks or railcars. An elevated structure supports the silo and loading equipment, allowing trucks and railcars to access beneath. The loadout equipment is enclosed within a silo skirt. The dry loading spout is ventilated to the silo's bin vent.

6. Water Treatment Reagents Handling

Lime and soda ash is stored in separate silos for use in the water treatment system. Each silo is equipped with a bin vent to collect fugitive dust generated during lime loading. The bin vents (RWS-BV-001 – lime and RWS-BV-002 – soda ash) are limited to a maximum outlet grain loading of 0.01 gr/dscf, (with a nominal airflow rate of 1,000 acfm).

7. Temporary Auxiliary Boiler

The temporary auxiliary boiler is used to provide supplemental heat when the PC-Boiler is operating on natural gas for activities such as steam blows or freeze protection during tuning or startup of the PC-Boiler. The facility does not have a permanent auxiliary boiler to supply supplement steam during periods of downtime, so a temporary portable auxiliary boiler is used. The auxiliary boiler is a trailer-mounted boiler with a capacity of 10,000 lb/hr of steam (approximately 11.8 MMBtu/hr). The boiler is rated for a maximum of 85 gallons per hour of No. 2 fuel oil at full load. The auxiliary boiler is used for initial warming of the system at the maximum rate of 10,000 pounds per hour. During start up of the forced draft and induced draft fans the auxiliary boiler can be used at low loads to prevent freezing in the tubes. Once startup has progressed to the point that the PC-Boiler is fired on coal, there will be no need for the auxiliary boiler. The auxiliary boiler is not operated at the same time the PC-Boiler is combusting coal, thus there is no increase in yearly potential emissions.

8. Activated Carbon Handling

Mercury sorbent is delivered to the facility by tractor trailer transport. Sorbent is pneumatically unloaded to a storage silo. The maximum truck unloading rate to the silo is 40,000 lb/hr and the maximum throughput of the sorbent injection system is 90 lb/hr. Therefore, 20 or less trucks will be unloaded per year, one load every 18 days. From the storage silo Hg sorbent is metered and transported to the sorbent injection system by a variable speed volumetric screw feeder. The screw supplies sorbent to a pneumatic eductor that provides the motive force to transport the sorbent to a single injection lance down exhaust stream of the air heater. The MAQP requires that the storage silo be equipped with a fabric filter bin vent (ACI-BV-001) to collect fugitive dust generated during loading and operation.

C. Permit History

On June 11, 2002, **MAQP #3185-00** was issued to Rocky Mountain Power, Inc. (RMPI) to construct a 113-MW electrical power generation facility approximately 1.2 miles northeast of Hardin, Montana. The facility consisted of a PC-Boiler and a steam turbine, which would drive an electric generator to produce a nominal 113-MW of electric power (11-MW of the power produced would be used by RMP).

On November 29, 2003, **MAQP #3185-01** was issued to allow RMPI to move the plant location by 610 meters, 10 degrees clockwise from North; reduce the SO_2 emission rate limit; reduce the PC-Boiler stack height; correct PC-Boiler exhaust temperature; add HCl and HF emission limits; and include short term emission limits for SO_2. The legal description of the facility's location would remain the same except it will be in the Northwest ¼ of Section 12 rather than the Southwest ¼ of Section 12. The location of all buildings, property boundaries, and emission sources would remain unchanged relative to each other. The PC-Boiler stack height was changed from the previously permitted level of no less than 350 feet to at least 250 feet above ground level. The PC-Boiler exhaust temperature was assumed to be 325 degrees Fahrenheit (º F) in MAQP Application #3185-00, but would actually be approximately 160º F. The MAQP was amended to include enforceable limits on HCl and HF emissions to ensure that the Hardin facility remained an area source (as opposed to a major source) with respect to Hazardous Air Pollutants (HAPs). In addition, short-term limits on SO_2 were included in the MAQP to protect short-term ambient air quality standards and increments. No emission increases would result from the amendment, however, RMPI provided modeling to support the facility move, stack height change, and PC-Boiler exhaust temperature correction. MAQP #3185-01 replaced MAQP #3185-00.

On April 30, 2004, the Department of Environmental Quality (Department) received an MAQP application from RMPI, requesting a change in the currently permitted control equipment on the PC-Boiler for SO_2 and PM_{10} emissions and changes in the facility's material handling systems, cooling system, and plant layout. The permitted system for SO_2 and PM_{10} emissions under MAQP #3185-01 included a wet venturi scrubber operated in conjunction with a multiclone. RMPI proposed to replace that with a lime SDA followed by an FFB. The changes in the cooling system and the consequential increase in potential PM_{10} emissions triggered review under the PSD program. The increased emissions were a result of the potential increase of the level of total dissolved solids (TDS) in the cooling system feed water, a more accurate water balance (which minimizes the amount of water discharged to evaporation ponds), and the previously overestimated cooling tower mist eliminator control efficiency, which could not be guaranteed in the current configuration. In addition, RMPI requested to correct the current HF limit that was established under MAQP #3185-01. Previously established limits associated with NO_x, carbon monoxide (CO), and Volatile Organic Compound (VOC) emissions from the PC-Boiler were not reviewed in this action because the proposed modifications would not affect them. The application was deemed complete on October 4, 2004.

In response to comments, several emission limits changed: SO_2 from 0.12 lb/MMBtu on a rolling 30-day average to 0.11 lb/MMBtu on a rolling 30-day average, filterable PM/PM_{10} from 0.015 lb/MMBtu to 0.012 lb/MMBtu, and Hg from 3.54 lb per trillion Btu (lb/TBtu) to 5.8 lb/TBtu with a testing plan to evaluate the feasibility of lowering that limit. In addition, a total PM/PM_{10} limit (that includes filterable and condensable fractions) was added. Additional discussion regarding these changes was included in Section III – Best Available Control Technology (BACT) Determination for MAQP #3185-02.

The Department Decision (DD) of MAQP #3185-02 was appealed to the Montana Board of Environmental Review (Board) by RMPI, the Montana Environmental Information Center, William J. Eggers III, Margaret J. S. Eggers, and Tracy Small. A settlement agreement was signed by all parties (including the Department) and approved in a Board order signed on May 6, 2005. The order included the following changes (in summary):

- Clarification that if water is used for dust suppression on unpaved portions of access roads, parking lots, and general plant area only clear, non-oily water that contains no regulated hazardous waste shall be used.

- 18-month optimization periods for SO_2 and PM_{10} during which temporary emission limits would apply. Following the 18-month optimization periods, the SO_2 (including control efficiencies) and PM_{10} limits would revert back to the BACT limits established in the DD of MAQP #3185-02. Through an MAQP application, RMPI may demonstrate to the Department that other limits are appropriate using information from the optimization periods.

- A 36-month demonstration period for Hg emissions during which RMPI would make the Hardin facility available as a test facility for Hg controls. By the end of that 36-month demonstration period, RMPI would install and operate an activated carbon injection system or equivalent technology for Hg control. An 18-month optimization period for the Hg control system would follow. Prior to the end of the 18-month optimization period, RMPI would submit an application to the Department with information from that Hg optimization period to determine an appropriate Hg BACT emissions limit.

In addition, in an unrelated action, the Department changed the rule reference on the requirement in the MAQP to comply with 40 Code of Federal Regulations (CFR) 60, Subpart Da from the Administrative Rules of Montana (ARM) 17.8.749 to ARM 17.8.340 and 40 CFR 60, Subpart Da. The change reflected information provided by RMPI (that was not available prior to the issuance of the DD) that reconstruction as defined under 40 CFR 60.15 had occurred for the PC-Boiler. This change was not a substantive change, and was being made at that time for convenience purposes. MAQP #3185-02 was issued final on May 16, 2005. **MAQP #3185-02** replaced MAQP #3185-01.

On December 20, 2005, the Department received a complete MAQP application from RMPI to add a temporary auxiliary 11.8 million British thermal units per hour (MMBtu/hr) boiler necessary for startup of the PC- Boiler. The temporary auxiliary boiler was to be used to provide supplemental heat when the PC-Boiler is operating on natural gas for activities such as steam blows or freeze protection during tuning or startup of the PC-Boiler. Once startup progressed to the point that the PC-Boiler is fired on coal, there would be no need for the auxiliary boiler. The auxiliary boiler would not be operated at the same time the PC-Boiler is combusting coal, therefore overall potential emissions at the facility did not increase. **MAQP #3185-03** replaced MAQP #3185-02.

On March 16, 2007, RMPI submitted an MAQP application for a modification to MAQP #3185-03. The application was deemed complete on August 3, 2007, upon RMPI's submittal of additional information. Specifically, RMPI requested the following actions: 1) specify that the current SO_2 short-term emission limit of 182.6 lb/hr does not apply during periods of PC-Boiler startup and shutdown or during SDA atomizer change-outs; 2) establish an alternate SO_2 short-term emission limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs; 3) define startup, shutdown, and SDA atomizer change-out periods and establish any related conditions; 4) request that the optimization period requirement for PC-Boiler SO_2 emissions control efficiency be established as a permanent MAQP condition; and 5) replace the temporary PM/PM_{10} and SO_2 emission limits established to apply during a defined optimization period with the post-optimization-period limits expressed in MAQP #3185-03.

In addition, on June 26, 2007, RMPI notified the Department of a pending merger with and into Rocky Mountain Power, Inc. (a Delaware Company (RMPD)) and RMPD's intent to transfer MAQP #3185-03 to RMP upon closing. On August 3, 2007, the Department received notification that the merger had closed. Therefore, the current permit action also transfers the MAQP from RMPI to RMP.

Further, the Department placed a 3-hour SO_2 limit on the PC-Boiler stack to minimize visibility impacts, which also reduced impacts to the 3-hour SO_2 increment. The Department based the proposed 3-hour limit on RMP's past operating data.

Lastly, while RMP is subject to the applicable requirements of the Acid Rain Program contained in 40 CFR 72-78, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department removed the condition requiring RMP to comply with the Acid Rain Program from the MAQP (ARM 17.8, Subchapter 8). Removing the requirement does not alleviate RMP from the responsibility of complying with the program and the requirement will be included in RMP's Title V Operating Permit (ARM 17.8, Subchapter 12), upon issuance. Removing the requirement for RMP to comply with the acid rain program simply clarifies that the Department's authority to implement the acid rain program is contained in ARM 17.8, Subchapter 12 (Title V Operating Permit Program). In addition, the monitoring requirements contained in 40 CFR 72-78 remain as applicable requirements in the MAQP. **MAQP #3185-04** replaced MAQP #3185-03.

D. Current Permit Action

On December 22, 2008, and April 16, 2009, the Department received application material from RMP proposing to modify Permit #3185-04. The modification proposed to establish an Hg emission limit for the HGS pursuant to ARM 17.8.771, and to provide an analysis of potential mercury control options including, but not limited to, boiler technology, mercury emission control technology, and any other mercury control practices. The application also included a proposed Hg emission control strategy. Additionally, RMP provided information relevant to, and requested that MAQP #3185-05 establish emission limitations and requirements satisfying, the 2005 Hardin Generating Station Settlement Agreement (Settlement Agreement) signed by the Montana Board of Environmental Review on May 6, 2005. The information provided described the results of the Hg Demonstration Period and Hg Optimization Period efforts required by the Settlement Agreement in order to establish a numeric Hg emission limitation based on performance of the BACT derived Activated Carbon Injection (ACI) base technology controls, in conjunction with the control system optimization efforts. Optimization testing and analysis to establish the BACT limit included co-benefit testing analysis of coal blending and coal additives; as well as, testing and analysis of injection of multiple activated carbon based commercially available engineered Hg sorbents into the exhaust stream after the air heater. Finally, RMP provided an analysis of effects on the permitted emission control equipment for the control of SO_2 and PM_{10}.

MAQP #3185-05 establishes a BACT based Hg emission limit in accordance with the reasonably demonstrated performance during the Hg Optimization Period pursuant to the Settlement Agreement, and an Hg emission limitation and associated operating requirements for the HGS in order to comply with ARM 17.8.771. Also, MAQP #3185-05 establishes the requirements for an Hg compliance monitoring plan pursuant to applicable rules and the Settlement Agreement. Finally, this permit action also updates rule references, permit format, and the emissions inventory. **MAQP #3185-05** replaces MAQP #3185-04.

E. Response to Public Comments

Person/Group Commenting	Permit Reference	Comment	Department Response
Rocky Mountain Power, LLC as Colorado Energy Management, LLC	Section II.C.20	(1) "It is rocky Mountain Power, LLC's understanding that the phrase 'install a sorbent/activated carbon injection (ACI) system' is intended to provide flexibility to allow for advancements occurring in the area of mercury emission controls. Please confirm that our understanding is correct. In addition Rocky Mountain Power, LLC, believes it would be appropriate to insert the phrase "or equivalent technology" at the end of the first sentence."	It is the Department's intent to provide for the maximum operational flexibility for the mercury control system, as permitted under ARM 17.8.771. However, in addition to ARM 17.8.771, Section II.C.20 is also based on the results of the BACT analysis process, as indicated by the ARM 17.8.752 citation. The proposed BACT based mercury limit and required control technology was established according to mercury control strategy demonstration project and optimization testing conducted in accordance with the Settlement Agreement. The optimization operational testing included a relatively specific type of mercury control system using a finite number of injectates to control mercury emissions. Therefore, changes to the mercury control system to an "equivalent technology", outside that defined in Section II.C.20 may require a permit modification including a revised BACT analysis and/or mercury limitations.
	Section II.C.21.	(2) The comment in generally expresses concerns that as written permit condition II.C.21 may subject the facility to vacated standards at 40 CFR 75 or some future requirement yet undefined. The comment suggests that condition II.C.21 should explicitly reference Attachment 4 to the permit.	Condition II.C.21 is included based on 40 CFR Part 75's inclusion in ARM 17.8.771. As noted in RMP's comments, the Department incorporated Attachment 4 into the mercury permits to clarify and specify the requirements that needed to be fulfilled with respect to mercury monitoring, recordkeeping, and reporting requirements. In addition, the Department worked through extensive public comments on the previously issued mercury permits in an effort to build a useful and robust Attachment 4 that would be relevant to all the sources subject to it. Based on Condition II.C.21 listing that RMP is subject to "applicable" conditions of 40 CFR Part 75 and that Attachment 4 lists specific requirements, the Department disagrees that any further clarification is necessary.
	Section II.E.1.	(3) "The following should be added to the list under E.1.: FGD ash silo baghouse WMH-BH-002, Reclaim coal belt baghouse RCF-BH-004, PAC silo bin vent 1-AQ-CI-SPAC-BV."	The emitting units and limitations identified in Section II.E.1 were established and permitted during a previous permitting action based on application materials germane to that permitting action. The 0.01 gr/dscf particulate emission limitations upon

			the emitting units established by Section II.E.1 is the result of BACT analysis during the original permitting action(s). For this permitting action, the result of the BACT analysis for the PAC silo bin vent "1-AQ-CI-SPAC-BV", referred to in the PD as ACI-BV-001, resulted in a different permit condition, which is established in Section II.E.5. The Department has no application materials or de minimis request on file for this permitting action requesting authorization for construction or operation of the emitting units identified as RCF-BH-004 or WMH-BH-002.
	Section I.A.3.i of Permit Analysis	(4) The comment suggests this section of the Permit Analysis should state "1,000 dscfm, 2hrs, semi-monthly or 12 hours/year" instead of the current process description language which describes the maximum sorbent daily throughput process of 90 lb/day.	On May 13, 2009 the Department requested the nominal dscfm flow rate and gr/dscf emission rating of the proposed bin vent (which the Department has referred to as ACI-BV-001). On May 14, 2009, ADA-ES, Inc. consultant to Colorado Energy Management, LLC, in care of Rocky Mountain Power, LLC responded to the Department's inquiry for these specifications per the affornementioned parties' request. ADA-ES, Inc. response stated that the requested information was not readily available and, as a process description, did not constitute a verifiable description of the process resulting in emissions. The Department proceeded in the Preliminary Determination to describe the permitted equipment based on the process information provided in the application materials as having a maximum daily product throughput of 90 lb/hr. Reference to tons per day units in Section I.A.3.i was a typographical error that has been corrected.
	Section I.B.3 of Permit Analysis	(5) The comment generally suggests revisions to discussion within the Permit Analysis that describes the coal storage and handling processes and permitted equipment. The comment suggests inclusion of an emitting unit within the discussion of permitted equipment and processes that is identified as RCF-BH-004.	The section of the Permit Analysis that is commented upon was developed and established in a previous permitting action based on application materials germane to that permitting action. The Department has no application materials or de minimis request on file for this permitting action requesting authorization for construction or operation of the emitting unit identified as RCF-BH-004. Minor editorial changes were made to Section I.B.3 of the permit analysis for clarity purposes.

	Section I.B.5 of Permit Analysis	(6) The comment generally suggests revisions to discussion within the Permit Analysis that describes the ash and spent lime handling systems permitted processes and emitting units. Also the comment suggests discussion that includes an emitting unit identified as "WMH-BH-002".	The section of the Permit Analysis that is commented upon was developed and established in previous permitting actions, based on application materials relevant to those permitting actions. The Department has no application materials or de minimis request on file for this permitting action requesting authorization for construction or operation of the emitting unit identified as WMH-BH-002. Minor editorial changes were made to Section I.B.5 of the permit analysis for clarity purposes.
	Section V of Permit Analysis	(7) The comment asserts that the baghouse and bin vent portion of the emission inventory requires updating to include emitting units as alluded to in comment 3 (above) and using actual hours of operations for each emitting unit.	The Department has no application materials or de minimis request(s) on file for this permitting action requesting authorization for construction or operation of the emitting units not already identified in the Permit and Permit Analysis. Generally, for administrative and programmatic purposes emission inventories presented within the permit analysis are established based on emissions allowed by the permit not the actual operations of the facility.
	Section V of Permit Analysis - emission inventory calcula-tion for activated carbon storage silo	(8) "The preliminary determination uses 90 lb/hr and 8760 hours of operation for their calculation. (page 27) This passive bin vent is only emitting while truck is filling silo. That would be six (6) times per year under worst case scenario. Emissions Calculation should be based on 1000 dscfm (typical truck blower), 12 hours per year." The comment continues by restating the emission calculations provided in the Preliminary Determination.	As discussed in response to comment (4) above the Department attempted to obtain the flow rate through the bin vent (which the Department has referred to as ACI-BV-001) during operation and silo filling, as well as grain loading bin vent pass-through for the purpose of establishing a BACT limit on the emitting unit and establishing an representative emission inventory. As described above, Rocky Mountain Power, LLC, indicated that there was no documentation available to verify the basis for establishing emission calculation using these methods. Therefore, the Department established emissions calculation for ACI-BV-001 based on the application information, after confirming the described process rates were representative and that emission factors used conformed to accepted values. The provided emission calculations are a representative estimate of the maximum allowable annual emissions from the bin vent based on its BACT determination. Unto itself the calculation in the emission inventory does not constitute a binding or practically enforceable permit condition.

F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

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 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.

   Initial performance tests were conducted for the PC-Boiler as directed by the New Source Performance Standards (NSPS), Subpart Da. Continuous emission monitoring systems (CEMS) are used to monitor ongoing NO_x compliance and SO_2 compliance. Continuous opacity monitoring systems (COMS) are used to monitor ongoing compliance with the opacity limitations. The Department has determined that annual Hg testing requirements shall be replaced by operation of the MEMS, which is subject to RATA testing under 40 CFR, Part 75, Based on the emissions from the PC-Boiler, the Department determined that initial testing for CO, PM_{10}, HCl, HF, and Hg was necessary. Finally, additional testing every 2 years is necessary to monitor compliance with the CO limit, and additional testing every 5 years is necessary to monitor compliance with the PM_{10}, HCl, HF, and H_2SO_4 emission limits.

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

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

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

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

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

1. ARM 17.8.210 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}

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

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

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

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

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

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

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

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

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The owner or operator or any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the applicable standards and provisions of 40 CFR Part 60.

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

    b. 40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. This subpart would apply to the RMP PC-Boiler because it is an electric utility steam generating unit with a heat input capacity greater than 250 MMBtu/hr. The PC-Boiler was built in 1968, prior to the applicability date of September 18, 1978. However, based on information provided by RMP (submitted on

April 5, 2005) regarding the upgrades made to the PC-Boiler, the Department determined that reconstruction (as defined under 40 CFR 60.15) has occurred; therefore, Subpart Da is applicable.

c. 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Although the RMP temporary auxiliary boiler is a steam generating unit with a maximum design heat input capacity that falls into the range of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr; it was constructed in 1984 prior to the applicability date of June 9, 1989. Therefore, Subpart Dc does not apply to the temporary auxiliary boiler.

d. 40 CFR 60, Subpart Y – Standards of Performance for Coal Preparation Plants. This subpart applies to the RMP facility because RMP was constructed after October 24, 1974, and the facility pulverizes or "crushes" more than 200 tons per day of coal.

8. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This rule incorporates, by reference, 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP). Since the emission of HAPs from the RMP coal-fired steam-electric generating facility is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the RMP facility is not subject to the provisions of 40 CFR Part 61. In addition, 40 CFR Part 61 does not apply because it does not contain any requirements applicable to RMP.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. This rule incorporates, by reference, 40 CFR Part 63, NESHAP for Source Categories. Since the emission of HAPs from the RMP coal-fired steam-electric generating facility is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the RMP facility is not a major source of HAPs.

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

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

2. ARM 17.8.402 Requirements. RMP must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). RMP made the appropriate demonstration of compliance with the ambient air quality standards.

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. RMP submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an MAQP (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 MAQP 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 MAQP 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. RMP has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, SO_2 and CO; therefore, an air quality permit is required.

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

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. RMP 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. RMP submitted an affidavit of publication of public notice for the January 15, 2009, issue of the *Big Horn County News*, a newspaper of general circulation in the Town of Hardin in Big Horn County, as proof of compliance with the public notice requirements.

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

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

8. ARM 17.8.755 Inspection of Permit. This rule requires that MAQP's 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 RMP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

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

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

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 identifies Hg emission limitation requirements, Hg control strategy requirements, and application requirements for Hg-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 and has the PTE 100 tpy or more of pollutants subject to regulation under the FCAA; therefore, the facility is major. The current permit action will result in a decrease of 0.2186 tpy mercury emissions will result from the use of the mercury control system. An estimated increase of 0.000199 tpy PM10 emissions will result from operation of the activated carbon injection/sorbent handling system (activated carbon silo). Therefore, this permitting action does not constitute a major modification under Prevention of Significant Deterioration.

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 greater than (>) 100 tons per year of any pollutant;

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

   c. PTE > 70 tons per year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #3185-05 for RMP, the following conclusions were made:

   a. The facility's PTE is > 100 tons per year for several criteria pollutants.

   b. The facility's PTE is < 10 tons per year for any one HAP and < 25 tons per year for all HAPs.

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

   d. This facility is subject to current NSPS standards (40 CFR 60, Subparts Da and Y).

   e. This facility is not subject to any current NESHAP standards.

   f. This facility is a Title IV affected source.

   Based on the above information, the RMP facility is a major source for Title V and, thus, a Title V Operating Permit is required. This MAQP application addressing Hg emissions and control was submitted concurrently with a Title V significant modification application. Title V Operating Permit #OP3185-01 will be modified to include the mercury provisions.

III. Mercury Control Technology Analysis

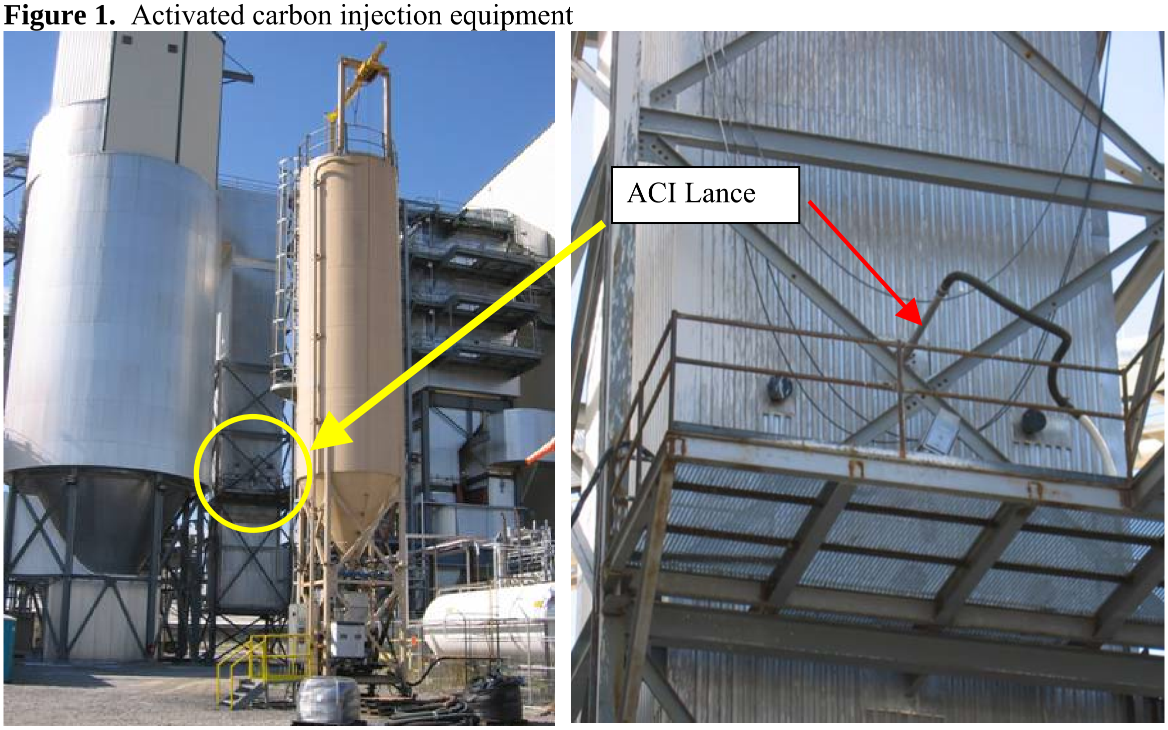
Pursuant to ARM 17.8.771, an analysis was submitted by RMP in permit application #3185-05, addressing available methods of controlling Hg emissions from the PC Boiler. This analysis also included the proposed Hg emission control strategy projected to achieve compliance with the 0.9 lb/TBtu emission limit established in this permit. The following discussion is the analysis submitted by RMP.

Under a Department of Energy (DOE) program, "Phase I" and "Phase II" field tests evaluated the most promising mercury control technologies, at full-scale, in a variety of power plant configurations. Although longer-term tests were conducted (up to 30 days), this period was not sufficient to definitively answer questions about the long-term consistency and the reliability of the system when integrated with plant processes or identify other balance-of-plant issues. Therefore, DOE "Phase III" projects were selected to determine system consistency and reliability, and the associated operation and maintenance costs for longer periods. Hardin was selected as a Phase III test site because the coal and emissions control equipment is representative of many new plants. The mercury control demonstration was conducted through funding from Colorado Energy Management, DOE NETL, ADA-ES, Inc., and other industry partners.

Previous industry testing at Powder River Basin (PRB) sites with selective catalytic reduction (SCR) showed little additional mercury oxidation across the SCR. In addition, results from Phase II industry testing at similar sites showed low native mercury removal across the SDA and FFB. Testing at sites firing PRB coals demonstrated that the effectiveness of non-chemically treated activated carbon is limited. Consequently, given the configuration at Hardin , the testing protocol focused on installing an ACI system using chemically-treated carbon and testing it along with a co-benefit analysis of the SCR, SDA, and FFB system, with and without additives to enhance the mercury oxidation performance of the SCR. The effectiveness of coal blending was also tested. Field-testing began in late 2006 and included baseline measurements, co-benefits analysis, parametric and long-term tests.

In order to conduct the field test at Hardin, a commercial-grade ACI system was installed at the air heater (AH) outlet, see Figure 1. This system included an activated carbon silo, an injection lance, and conveying equipment. Powdered activated carbon was delivered in 1000 lb sacks or bulk pneumatic trucks and loaded into the silo, which was equipped with a bin vent bag filter. From the discharge section of the silo, the sorbent was metered by variable speed screw feeders into eductors that provide the motive force to carry the sorbent through steel pipe with long-radius, ceramic-lined elbows to the injection lance. A poly-logic control (PLC) system was used to control system operation and adjust injection rates.

Figure 1. Activated carbon injection equipment



The project consisted of the following three major phases: baseline, parametric, and long-term testing. Baseline testing was conducted in October 2006 and involved the measurement of speciated mercury concentrations across the SDA and FFB without carbon injection. Co-benefit evaluations included assessing mercury speciation and overall removal observed over a wide range of plant operating conditions to assess the effects of the various components of the pollution control and combustion systems. During co-benefit testing, coal additives and coal blending to enhance mercury oxidation across the SCR and subsequent removal in the SDA and FFB were also studied. Parametric tests were conducted in the spring of 2007 to evaluate various sorbents with and without co-benefit enhancements. The parametric phase concluded with a final test in August 2007. The purpose of this final test was to demonstrate that the results from the short-term (several hours) parametric tests could be reproduced over longer periods (several days) before proceeding to the long-term test.

In September of 2007, a nitrogen generator was installed on the mercury CEMS that significantly improved performance and accuracy. Signal noise was reduced by a factor of ten that greatly improved the reliability of analyzer calibrations and decreased the uncertainty in mercury removal calculations. Based upon the precision and accuracy of the mercury measurements prior to upgrades, all data points (including short-term results from parametric testing) need to be interpreted to incorporate an error band of approximately ± 5% (e.g., 90% removal could be as low as 85%).

The long-term test began on September 26, 2007, with the continuous injection of DARCO® Hg-LH (a treated carbon). For most of the long-term test, the ACI system was operated in automatic mode with feedback control from the Hg CEMS to maintain mercury removal. Originally, a single sorbent was going to be used for the duration of the long-term test. However, during parametric testing, there was almost no discernable difference between the performance of DARCO® Hg-LH and Calgon FLUEPAC®-MC PLUS. Therefore, the project team decided to use Calgon FLUEPAC®-MC PLUS for the final two months of the project, which ended in November 2008.

It is important to note that, during the long-term test, the plant experienced several operational issues that make the majority of the data non-representative of normal operations. After consultation with DOE, it was determined the long-term testing would continue. The plant experienced a failure of the step-up transformer in December 2007 that led to an extended outage and limited the plant to 105 MW out of 121 MW during most of 2008. Also, a major tube leak in March 2008 plugged 25+% of the SCR with ash. A new step-up transformer was installed in July 2008, but the operation of the plugged SCR still affected PAC performance. The SCR was refurbished in October 2008. Consequently, the most recent data collected is most representative of normal plant operations and is used to establish the reasonable demonstrated performance of the system and the achievability of 0.9 lb/TBtu (BACT limit).

The test protocol and results are discussed below with respect to potential effects of tested mercury control strategies on other pollutant controls. The plant has reported no problems with the SDA, FFB, or stack emissions as a result of carbon injection during long-term testing. Specifically, particulate testing (front half) at the stack indicted no significant difference between baseline (22.1 and 18.3 lb/hr) and ACI testing (20.1 lb/hr).

- **Viability or feasibility of potential mercury control strategies.**

The following describes the test procedures for the various phases of testing at Hardin. The results, along with other factors such as whether licenses were commercially available, were used to determine viable technologies for meeting the 0.9 lb/TBtu mercury emission limit (BACT limit).

Baseline Test Procedure

A series of baseline tests were conducted to establish the mercury removal during typical plant operating conditions. There was no addition of mercury sorbent or any other chemical additive during this period. Baseline measurements included one complete set of flue gas measurements and sample analyses for particulate, mercury, halogens, and ammonia at the AH outlet and stack. The accuracy of the Hg CEM was verified with the Ontario Hydro Method and backed up with the Sorbent Trap Method (STM).

Co-Benefits Analysis Procedure

A series of tests were conducted to determine if mercury capture across the SDA and FFB could be enhanced by changes in plant operations or by the use of coal additives or coal blending. This task consisted of three parts. Part one involved long-term observation of the plant systems in respect to how variances from normal operations affected mercury speciation and subsequent capture. Part two included the use of a bromine-based coal additive offered in the U.S. by Alstom as KNX® to determine its effect on mercury oxidation across the SCR and subsequent mercury capture in the SDA and FFB. For this test, KNX® was pumped to the three feeders and metered directly onto the coal, and mercury speciation and concentration was measured at the AH outlet and stack with the Hg CEMs. The final part of the co-benefit analysis involved coal blending with two western bituminous coals, West Elk and Bull Mountain. These coals have a higher chlorine level than the local coal (Absaloka = 12 ng/g Cl, West Elk = 85 ng/g Cl, Bull Mountain = 27 ng/g Cl), and DOE Phase II tests results showed that increased halogens can increase overall native mercury removal (no sorbent injection) in the SDA and FFB. For this test, blends of 7 and 15% western bituminous coal were made by using a portable conveyor and hopper to meter and load the test coal onto the main coal belt while the coal bunkers were being filled. Each blend was burned for at least eight hours and Hg CEMs measurements were used to determine how the blends affected mercury speciation and removal.

Parametric Test Procedure

The purpose of the parametric test was to evaluate the full-scale mercury capture performance of two sorbents, DARCO® Hg-LH and Calgon FLUEPAC®-MC PLUS, at various injection rates to establish a performance curve for each sorbent. Each sorbent injection rate was tested for 4 to 12 hours. A typical test involved loading a supersack (~1000 lb) of the candidate material into the silo, calibrating the feeder with the new sorbent, and then injecting the material at a single rate until steady-state conditions were reached as determined by the Hg CEM measurements. The rate was then changed for the next point on the performance curve.

Several additional tests were added to the scope of the parametric test because of the encouraging results of the KNX® test. These included tests that combined KNX® addition with sorbent injection to determine if mercury capture by activated carbon could be enhanced by the addition of KNX®. In these tests, the addition rate of both the KNX® and carbon was varied to establish a performance curve for the combined system.

Based on the results of the parametric tests, the best options for achieving the program goals during a long-term test were identified by the project team. These options were then evaluated during two-day test periods to verify the performance obtained during the shorter-term parametric tests. Following the successful completion of the verification tests, the DOE approved a continuance of the project into the long-term test phase.

Long-Term Test Procedure

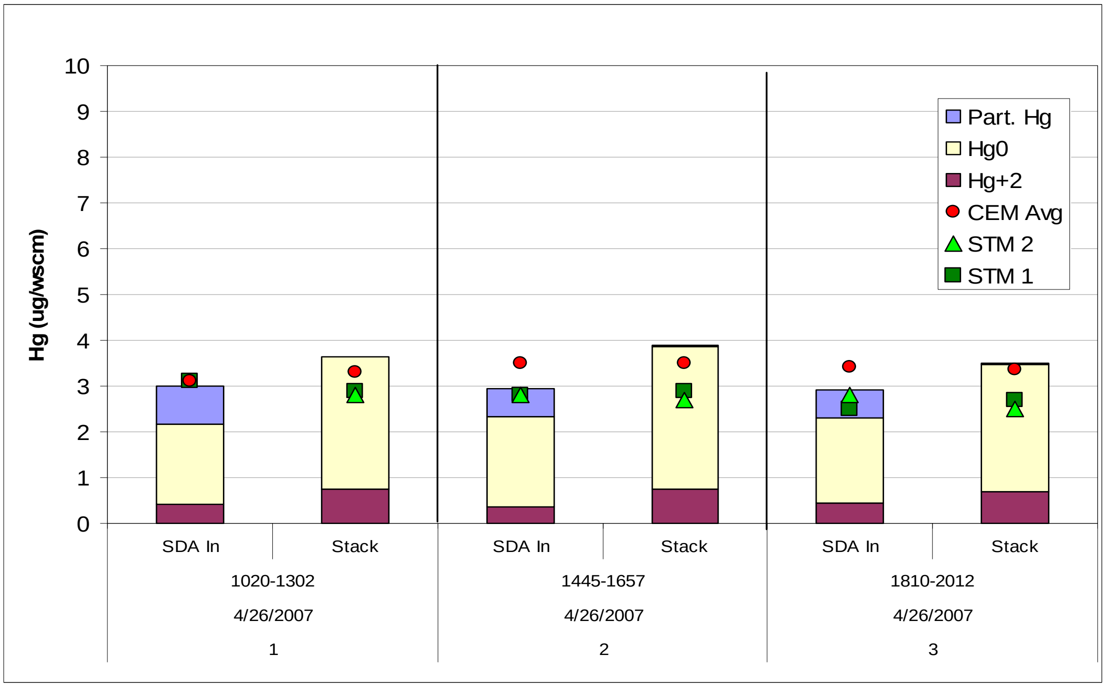
The purpose of the long-term tests was to determine the mercury removal performance, long-term emissions variability, and associated O&M costs of ACI for mercury control. Potential operational impacts being monitored include degradation of SDA, FFB, or injection system performance. During long-term testing, mercury measurements using Hg CEMs were collected. The stack CEM was operated remotely using the QA/QC procedures outlined in the now vacated Clean Air Mercury Rule (CAMR) and compliance monitoring requirements included in 40 CFR Part 60.49a. These included daily zero and span checks and quarterly linearity checks. A relative accuracy test was conducted on the Hg CEM during the long-term program.

As mentioned, the long-term test began at the end of September 2007 and ended in November 2008. In April 2008, the carbon injection system was integrated with the Hg CEMs to automatically control mercury removal. The plant experienced several operational issues during the long-term test that resulted in the most recent data collected being the most representative of normal plant operations. As such, this data should be used to establish an applicable limit.

Baseline Test Results

Baseline measurements were conducted in April 2007. Figure 2 shows three sets of simultaneous measurements made using three different mercury measurement techniques at the SDA inlet and stack. The Ontario Hydro data are presented as stacked bar graphs combining the particulate, elemental, and oxidized mercury segments. STM pairs are represented as squares and triangles. Finally, Hg CEM data are plotted as circles. In general, the data show good agreement between the three methods.

Figure 2. Comparison of mercury measurements for the baseline test

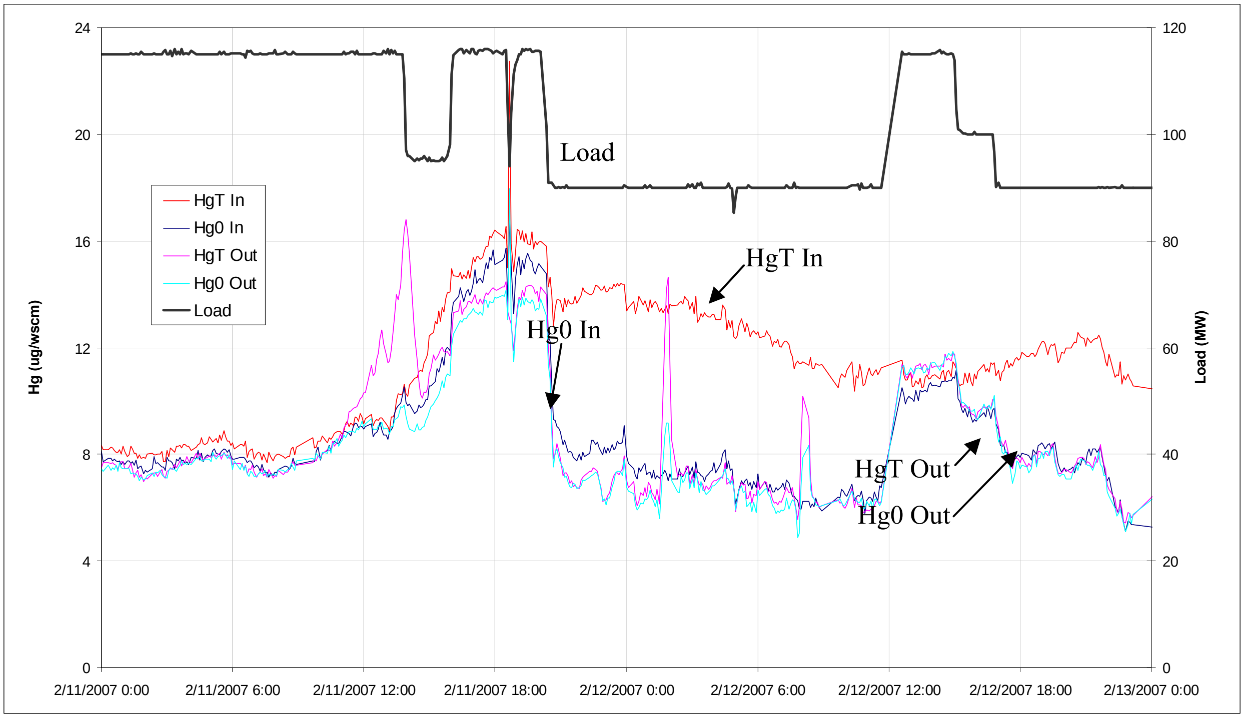


Co-Benefit Results

The most significant finding of the co-benefit analysis was that mercury speciation changes across the SCR when the plant reduces load and this significantly impacts native mercury capture. Figure 3 shows Hg CEM data and plant load during a two-day period when the plant reduced load on several occasions. The figure shows that at full load the Hg CEM readings at the SDA inlet and at the stack have nearly the same value. This indicates that there is little native capture and that there is almost no oxidized mercury at the inlet or stack (i.e., HgT = Hg0). However, when the plant reduces load two effects are apparent from the figure: 1) the outlet mercury decreases to as little as 50% of the inlet mercury, indicating relatively high native mercury capture, and 2) the inlet Hg0 value falls to near the outlet values (HgT Out and Hg0 Out are usually nearly equal). This indicates that significant amounts of oxidized mercury are being formed across the SCR and that this mercury is captured by the SDA and FFB. It is theorized that this is caused by the higher oxygen values, lower temperatures, and higher residence times (i.e., lower gas velocities) within the SCR when the unit is at low load.

This finding is important when considering the long-term results, because due to the failure of the step-up transformer in December 2007, the plan operated for an extended period during 2008 at lower load.

Figure 3. Co-benefit result—SCR oxidation at low load

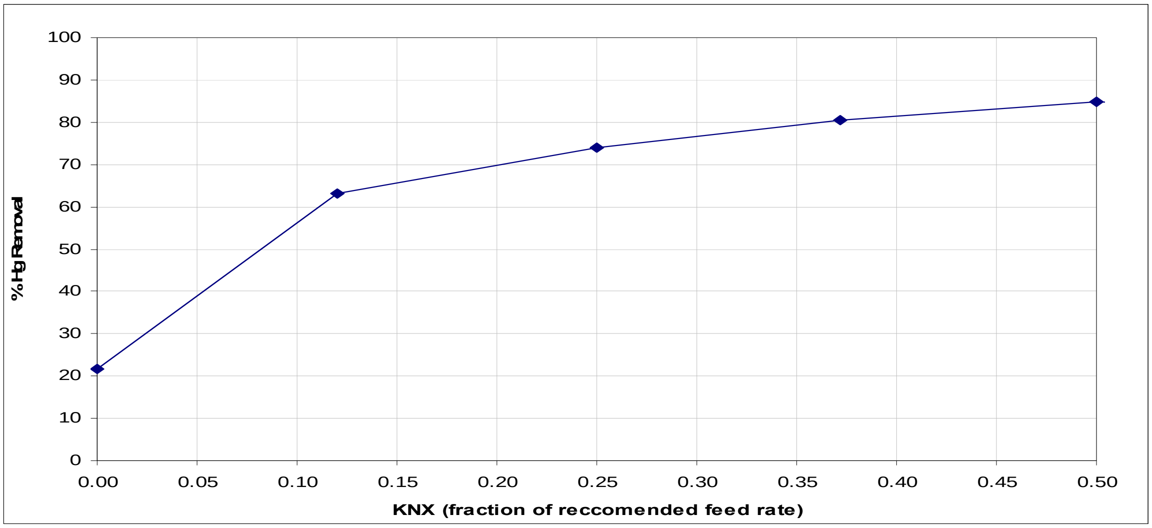


Coal Additive Results

The coal additive tests were completed in April 2007. This test involved injecting KNX® onto the coal just before the mill during baseline conditions (i.e., no carbon injection). Different rates of KNX® addition were tested and the reference rate was calculated to produce a bromine concentration in the flue gas recommended by the vendor (Alstom).

Changes in the inlet and outlet mercury concentrations were registered on the Hg CEMs within minutes of starting the injection pump, and the system returned to baseline conditions within minutes of discontinuing KNX® addition. Prior to beginning injection, the inlet and outlet mercury values were nearly equal for both total mercury (HgT) and elemental mercury (Hg0), indicating little native capture and no oxidation across the SCR. After starting coal treatment with KNX®, the inlet HgT value dropped slightly which may indicate particulate bound mercury that is not measured by the CEM. The outlet HgT value dropped significantly, indicating as much as 85% mercury capture at a KNX® injection rate of only half that recommended by the vendor. Also, the inlet Hg0 value dropped to about the same as the outlet values, indicating that a significant amount of oxidized mercury was being formed in the SCR and removed in the SDA and FFB. Figure 4 shows the results of the coal additive test.

Figure 4. Results of the coal additive (KNX®) test



Coal Blending Results

The coal blending tests were completed in December 2006. Two western bituminous coals, West Elk and Bull Mountain, were tested at blend nominal ratios of 7% and 15%. Table 1 lists the averages of the coal analyses performed for the blending tests. It shows that the West Elk coal had a much higher chlorine concentration (7X) than either the Absaloka or Bull Mountain, although the Bull Mountain coal had about twice the chlorine concentration as the Absaloka. Therefore, it was likely that the West Elk coal blends would produce better results.

Table 1. Average coal analyses for the coal blending tests

As Rec'd	Absaloka	West Elk	Bull Mountain
HHV, Btu/lb	8,914	12,387	10,194
Hg (ng/g)	33.49	52.15	34.79
Cl (ug/g)	12.35	85.04	26.90
% C	51.63	68.40	58.24
% H	3.45	4.88	3.91
% S	0.54	0.55	0.53
% O	11.48	9.25	11.41
% N	0.72	1.57	1.07
% H_2O	24.43	6.56	18.21
% Ash	7.76	8.80	6.66
Total	100.00	100.00	100.00

Table 2 shows the results of the blend tests. In general, the West Elk performed well; up to 50% mercury capture was observed when co-firing at a 14% blend. No significant increase in native capture was observed with the Bull Mountain coal; however, it should be noted that a steady increase in the background coal mercury concentration during this test made it difficult to pinpoint a baseline value for comparison.

Table 2. Results of the coal blending tests

Blend Coal	Blend Ratio	Hg Removal Native ~ 10%)
West Elk	7%	10-30%
West Elk	14%	50+%
Bull Mountain	7%	0-10%
Bull Mountain	14%	0-10%

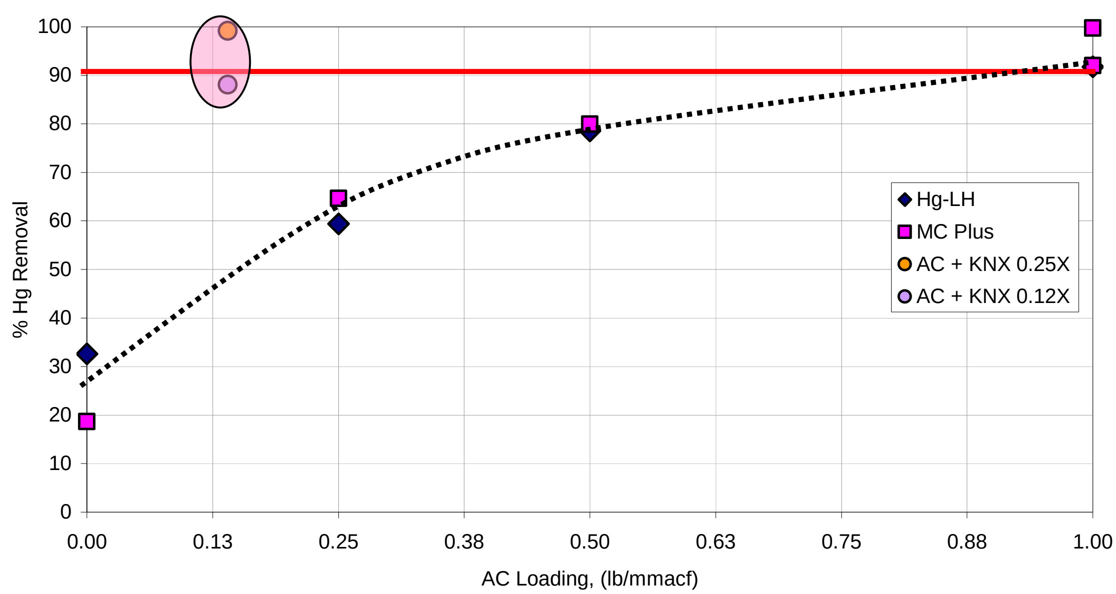
Parametric Test Results

The parametric tests were completed in the spring of 2007. Two brominated carbons were tested: DARCO® Hg-LH and Calgon FLUEPAC®-MC PLUS. Three injection rates were tested corresponding to carbon loadings in the flue gas of 0.25, 0.50, and 1.0 lb/MMacf. The combination of coal additive KNX® with ACI was also tested.

Figure 5 shows the results of the parametric tests. The figure shows that there was little difference in the performance of the two carbons. For both carbons, 90% mercury capture was obtained at carbon loadings of about 1.0 lb/MMacf. The figure also shows that high mercury removal is possible at Hardin by combining sorbent injection with the use of coal additive KNX®. In two tests, high mercury capture was achieved at very low carbon loadings and relatively low KNX® injection rates.

As mentioned previously, several upgrades were made to the Hg CEMS after the parametric test that significantly improved performance and accuracy. Signal noise was greatly reduced. Based upon the precision and accuracy of the mercury measurements prior to upgrades, all data points shown on Figure 5 should be interpreted to incorporate an error band of approximately ± 5% (e.g., 90% removal could be as low as 85%).

Figure 5. Results of the parametric tests



Long-Term Test Results

Prior to beginning the long-term test, the project test plan called for conducting several days of final testing with the sorbent(s) that showed the best performance during the parametric tests. The purpose of the optimization test was to demonstrate that the chosen sorbent could meet project objectives over longer test periods (2 days) than the short-term (4-hour) parametric tests. However, since the DARCO® Hg-LH and Calgon FLUEPAC®-MC PLUS performed equally as well, both were tested for two day periods. The results of the optimization tests showed that "target" mercury capture could be maintained with both DARCO® Hg-LH and Calgon FLUEPAC®-MC PLUS, but at a slightly higher carbon loading (1.5 lb/MMacf) than obtained during the parametric tests (1.0 lb/MMacf). In April 2008, the carbon injection system was integrated with the Hg CEMS to operate on automatic most of the time so that the carbon injection rate was updated every 45 minutes to maintain the DOE project "target" mercury capture ± 0.5%.

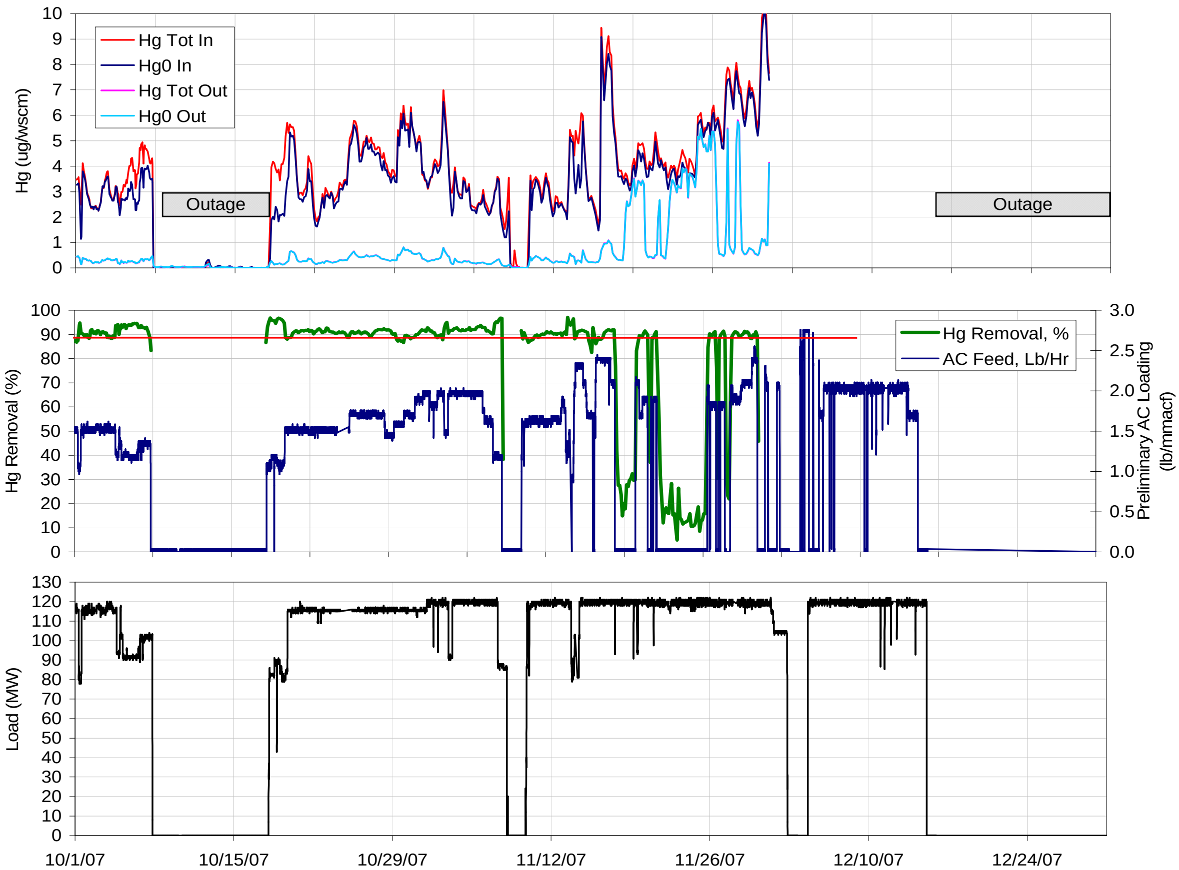
It should also be noted that the combined activated carbon/KNX® system was not chosen for the long-term test because licenses were not available commercially for this air pollution control configuration at the time. Only commercially available options were considered for long-term testing.

As mentioned, long-term testing began in late September 2007. However shortly after commencing this phase, the plant was operating at reduced load due to a problem with the step-up transformer, or the SCR being 25+% plugged during most of this test. After consultation with DOE, it was determined the long-term testing would continue. These operating conditions impacted the performance of the ACI system, both positively and negatively, and should not be used to establish a reasonable demonstration of performance. In addition, due to the coal variability, the inlet concentrations at Hardin can vary over a wide range, thus following the control efficiency is not the most representative way to determine performance. For example, there are periods when even 90+% control results in emissions above 0.9 lb/Tbtu (BACT limit). Moreover, other unexpected circumstances occurred, such as a delivery of carbon with lower than normal bromine, that also impacted ACI system operation and results.

The following bullets and notes provide a timeline for the long-term testing, and Figures 6 through 8 are provided to demonstrate how the operational issues impacted mercury control. The graphs show the Hg CEMS data at the SDA inlet and stack, the carbon loading, and plant load. The figures also demonstrate how the inlet mercury at Hardin can vary.

- 4^{th} Quarter 2007 – see Figure 6
  - Long-term test began previous week;
  - Normal operations until failure of the step-up transformer on December 15^{th} and the resulting outage;
  - Note the varying inlet Hg concentrations and resulting variability in outlet concentrations.

Figure 6. Long-term test - 4Q07



- 1st Quarter 2008 – see Figure 7
  - February 2008 – plant resumes operation but at lower loads with temporary transformer;
  - Early March – delivery of a new truck of activated carbon with low bromine and nearly 4 lb/MMacf was required to achieve "target" removal (when the next truck of carbon was delivered, the carbon requirements returned to typical);
  - March 13, 2008 – major tube leak, resulting in plugged SCR.

- 2nd and 3rd Quarters 2008 – see Figure 8
  - Operation at lower load shown for period in May 2008 in Figure 8, note that there is some oxidation at the inlet because the plant is at reduced load as discussed above, the outlet data show that no oxidized mercury is present;
  - new step-up transformer installed in July 2008;
  - August 2008 – began 2-month test with Calgon FLUEPAC®-MC PLUS.

Figure 7. Long-term test - 1Q08

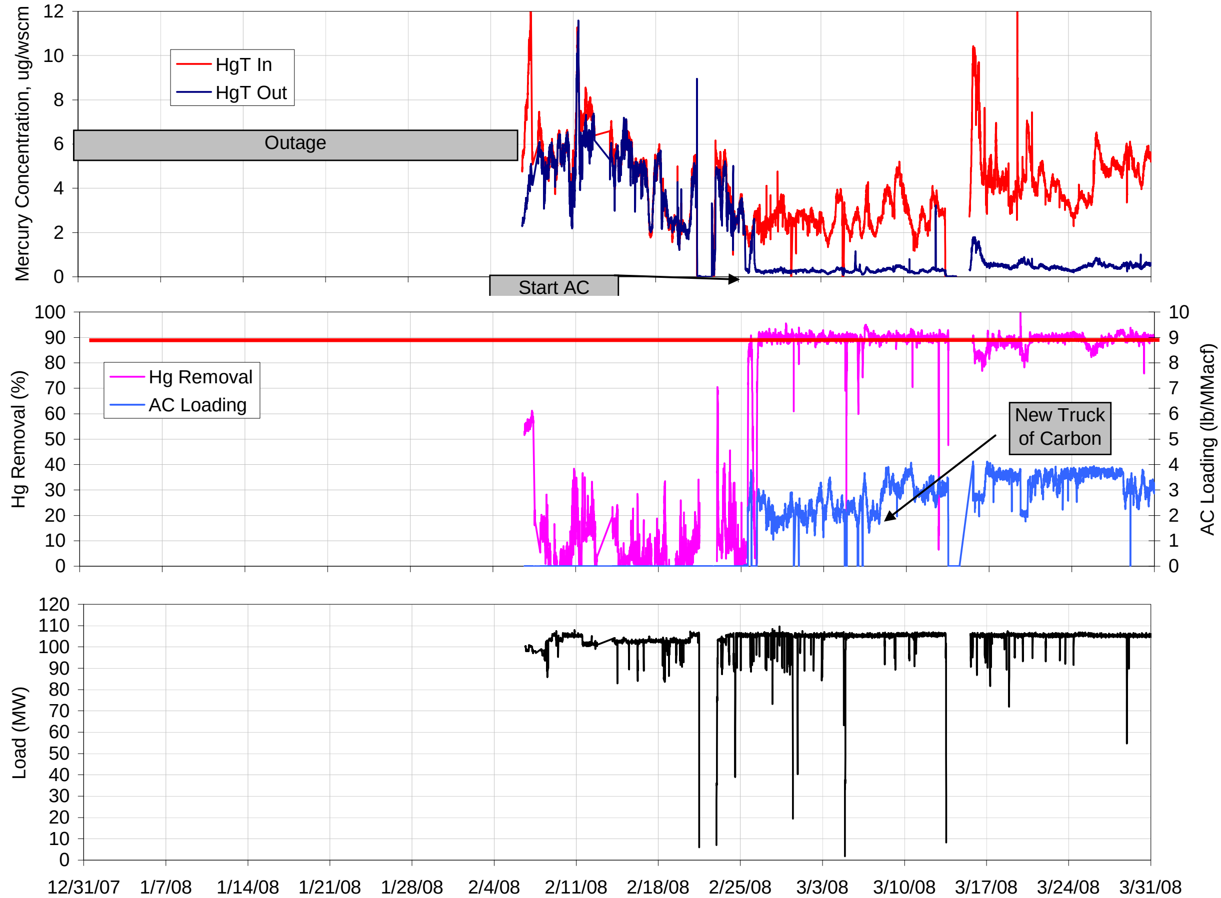
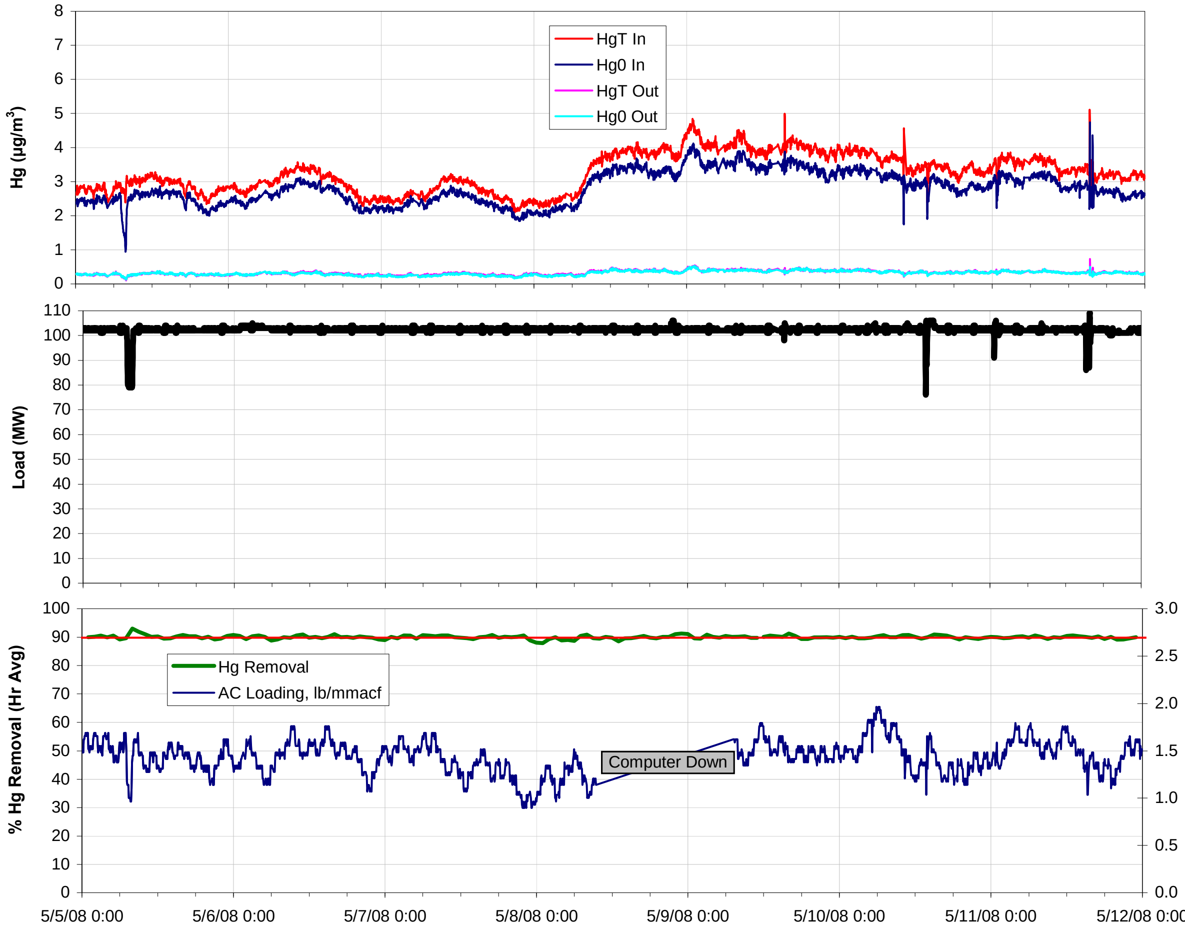


Figure 8. Long-term test (lower load condition)



- 4th Quarter 2008, through November
  - October 2008 – outage to refurbish SCR;
  - November 17, 2008 – long-term DOE test completed.

- December 2008 to 1st Quarter 2009
  - additional testing of another sorbent for flexibility in sourcing;
  - automatic emission control to 0.9 lb/Tbtu – Hg Optimization Period;
  - Optimization period ends March 2009.

As mentioned previously, the most recent data collected are most representative of normal plant operations and should be used to establish the reasonable demonstrated performance of the system and the achievability of 0.9 lb/Tbtu (BACT limit). Figure 9 presents outlet mercury and PAC loading results for a sample period during the Hg Optimization Period (time following the DOE long-term testing with automatic control in place). Table 3 is a summary of statistics for operation of the system during the same period (January 14 through February 9, 2009). As mentioned previously, to date the plant has reported no problems with the SDA, FFB, or stack emissions as a result of carbon injection.

Figure 9. Sample results during Hg Optimization Period

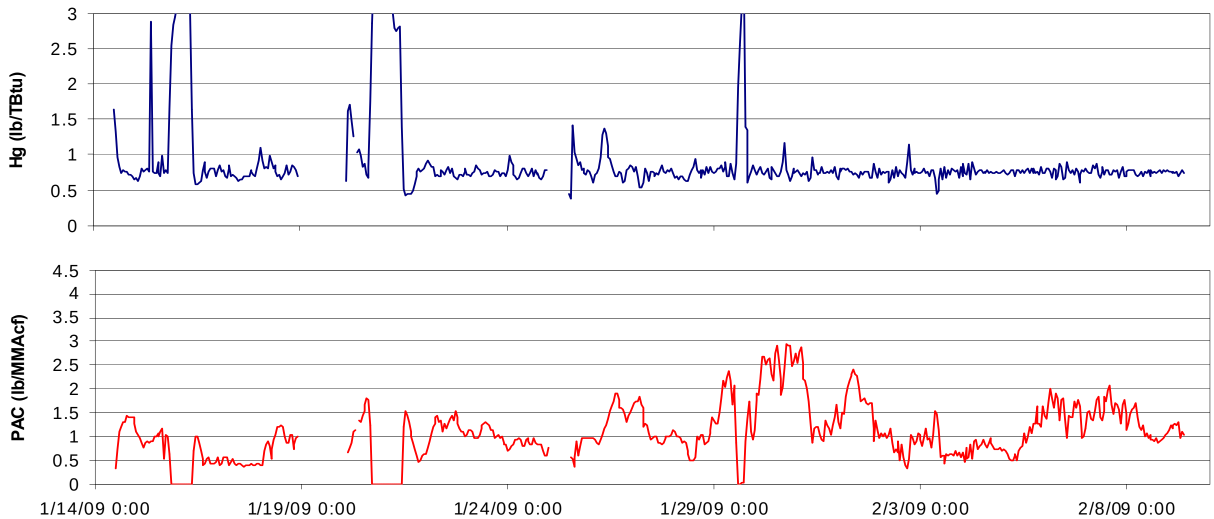


Table 3. Summary statistics during Hg Optimization Period (January 14 to February 9, 2009)

Load Average (MW)	PAC Average (lb/MMacf)	Inlet Mercury (ug/m^3)		Outlet Mercury Average (lb/TBtu)
		Maximum	Average	
116.2	1.2	7.3	4.7	0.8

The mercury control strategies proposed in the submittal for Hardin are based on the long-term testing results. As the control strategy shown best able to achieve the target reduction, Rocky Mountain Power's current approach is to use activated carbon injection for the Hardin Generating Station to meet the limit in 17.8.771(1)(b)(ii). KNX™ and activated carbon injection may be pursued in the future pending resolution of contractual details. Data from parametric and long-term testing indicate compliance with the proposed mercury emission limit of 0.9 pounds per trillion Btu, calculated as a rolling 12-month average, using either approach. Data from the Hg Optimization Period also support this approach.

IV. BACT Determination

A. Activated Carbon Silo Bin Vent (ACI-BV-001)

RMP proposes control of emissions from the sorbent storage silo using a bin vent equipped with a fabric filter. The control option selected has controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

B. Mercury Emission BACT Limit Determination

Pursuant to the Settlement Agreement, the Department shall establish a BACT based mercury emission limitation based the "reasonable demonstrated performance during the Hg Optimizaiton Period". RMP performed a 25-day optimization test, during which plant operation is characterized by RMP as being representative of normal operations and a valid representation of reasonably achievable long term mercury control. During the Optimization period RMP monitored Hg down exhaust stream from the air heater and at the stack using the installed MEMS. Based on the results of the Hg Demonstration and Optimization Periods RMP as described in Section III above RMP asserts 0.9 lb/TBtu as a 12-month rolling average constitutes an appropriate BACT limit for the PC-Boiler. The Department concurs with this conclusion.

V. Emission Inventory

	Ton/Year								
Source	PM/PM_{10}	NO_x	CO	VOC	SO_x	HCl	HF	H_2SO_4	Hg
PC-Boiler	68.54	514.04	856.73	19.42	628.27	6.75	2.93	35.98	0.00514
Cooling Tower	45.04								
Baghouse and Bin Vents	26.11								
Truck Traffic Fugitives	0.26	0.09	0.18	0.04	0.13				
Temporary Auxiliary Boiler*	0.09	0.85	0.21	0.01	0.30				
Totals	139.95	514.13	856.91	19.46	628.40	6.75	2.93	35.98	0.027

*The emissions from the temporary auxiliary boiler are not included in the total plant emissions because the temporary auxiliary boiler is prohibited from operating when the PC-Boiler is combusting coal. Therefore, those emissions would not occur at the same time and are not additive.

<u>PC-Boiler Emissions</u>

Size = 116 MW
Hours of Operation = 8,760 hr/yr
Heat Input = 1304 MMBtu/hr
Fuel Heating Value = 8,700 Btu/lb of coal

PM/PM_{10} Emissions
Emission Factor: 0.012 lb PM/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.012 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 68.54 ton/yr

NO_x Emissions
Emission Factor: 0.09 lb NO_x/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.09 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 514.04 ton/yr

CO Emissions
Emission Factor: 0.15 lb CO/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.15 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 856.73 ton/yr

VOC Emissions
Emission Factor: 0.0034 lb VOC/MMBtu {BACT Limit}
Calculations: 0.0034 lb VOC/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 19.42 ton/yr

SO_x Emissions
Emission Factor: 0.11 lb/MMBtu {BACT Limit}
Calculations: 0.11 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 628.27 ton/yr

HCl Emissions
Emission Factor: 0.00118 lb/MMBtu {Permit Limit}
Calculations: 0.00118 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 6.75 ton/yr

HF Emissions
Emission Factor: 0.00051 lb/MMBtu {Permit Limit}
Calculations: 0.00051 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 2.93 ton/yr

H_2SO_4 Emissions
Emission Factor: 0.0063 lb/MMBtu {Permit Limit}
Calculations: 0.0063 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 35.98 ton/yr

Hg Emissions
Emission Factor: 0.900 lb/TBtu {Permit Limit, BACT Limit}
Calculations: 0.000000900 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 0.00514 ton/yr

Cooling Tower Emissions

Water intake rate =	1,400 gpm
Total liquid drift =	0.001% of circulating water flow
Design circulating water rate =	68,500 gpm
Total dissolved solids (TDS) intake =	1,250 ppm
Concentration cycles =	up to 24
Circulating TDS =	30,000 lb TDS/10^6 lb H_2O
Hours of Operation =	8,760 hr/yr

PM_{10} Emissions

Calculations: 0.001 lb drift/100 lb H_2O * 68,500 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 30,000 lb TDS/10^6 lb H_2O * 8760 hr/yr * 0.0005 ton/lb = 45.04 ton/yr

Baghouse and Bin Vent Emissions

Coal unloading (RCF-BH-001) flow rate =	50,000 dscfm
Coal silo (RCF-BH-002) flow rate =	7,500 dscfm
Coal storage bunkers (RCF-BH-003) flow rate =	5,000 dscfm
SDA lime silo (FGT-BV-001) flow rate =	1,000 dscfm
FGD ash silo (WMH-BV-003) flow rate =	2,000 dscfm
Recycle ash silo (FGT-BV-002) flow rate =	2,000 dscfm
Water treatment lime silo (RWS-BH-001) flow rate =	1,000 dscfm
Soda ash silo (RWS-BH-002) flow rate =	1,000 dscfm
Hours of operation =	8,760 hr/yr

PM/PM_{10} Emissions

Emission Factor: 0.01 gr/dscf {Permit limit}

RCF-BH-001 Calculations: 50,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 18.77 ton/yr

RCF-BH-002 Calculations: 7,500 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 2.82 ton/yr

RCF-BH-003 Calculations: 5,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 1.88 ton/yr

FGT-BV-001 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

WMH-BV-003 Calculations: 2,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.75 ton/yr

FGT-BV-002 Calculations: 2,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.75 ton/yr

RWS-BH-001 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

RWS-BH-002 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

Activated Carbon/Sorbent Storage Silo (ACI-BV-001)

Truck Unload:

Emission factor:	0.00099 {AP-42 11.12-2 Controlled, ARM 17.8.752}
Emission Calculations:	0.00099 lb/ton * 90 lb/hr * 0.0005 ton/lb = 0.000045 lb/hr
Emission Calculations:	0.000045 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.000195 ton/yr

Working Emissions:

Emission factor:	{AP-42 13.2.4, Permit limit}
Emission Factor =	k * 0.0032 * $((U/5)^{1.3}/(M/2)^{1.4})$ * (1- Control Efficiency)
	Where k = 0.35, U = 2.0 (indoor process), M = 0.1% and Assumed Control Eff = 99.9%
Emission Factor =	0.000023 lb/ton
Emission Calculations:	0.000023 lb/ton * 90 lb/hr * 0.0005 lb/ton = 0.000001 lb/hr
Emission Calculations:	0.000001 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.00000445 ton/yr

Truck Traffic Fugitives

Assumptions:

Distance of each round trip =	0.5 mile
Total trips =	2 trips/hr, every hour of the year

Driving surface = paved

PM/PM_{10} Emissions (Fugitives)

Emission Factor: 0.06 lb/VMT {Calculated from AP-42 Equation, 13.2.1 (10/97)}

Calculations: 0.06 lb/VMT * 0.5 VMT/trip * 2 trips/hr *8760 hr/yr * 0.0005 ton/lb = 0.26 ton/yr

Temporary Auxiliary Boiler Emissions

Hours of Operation = 1,000 hr/yr (Permit Limit)

Heat Input = 11.8 MMBtu/hr

Maximum fuel rate = 85 gal/hr of No. 2 fuel oil

PM/PM_{10} Emissions

Emission Factor: 2 lb PM/ 1000 gal fuel {AP-42, Table 1.3-1}

Calculations: 2 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.09 ton/yr

NO_x Emissions

Emission Factor: 20 lb NOx/ 1000 gal fuel {AP-42, Table 1.3-1}

Calculations: 20 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.85 ton/yr

CO Emissions

Emission Factor: 5 lb CO/ 1000 gal fuel {AP-42, Table 1.3-1}

Calculations: 5 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.21 ton/yr

VOC Emissions

Emission Factor: 0.252 lb VOC/1000 gal fuel {AP-42, Table 1.3-3}

Calculations: 0.252 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.02 ton/yr

SO_x Emissions

Emission Factor: 142 * S lb/ 1000 gal {Permit Limit for fuel sulfur content ≤ 0.05%}

Calculations: 142 * 0.05 lb/1000 gal * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.30 ton/yr

VI. Existing Air Quality

The facility is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The air quality of this area is classified as either "Better than National Standards" or unclassifiable/attainment of the MAAQS and NAAQS for criteria pollutants.

VII. Ambient Air Impact Analysis

Ambient air impact analysis was conducted for permit version 3185-04 (October 23, 2007), 3185-02 (May 16, 2005), 3185-01 (November 29, 2003) and 3185-00 (June 11, 2002). Based on those analyses and the fact mercury emissions will decrease and criteria pollutant emission increases are relatively minor, the Department has determined that the impacts from this permitting action will be minor. The Department believes it will not cause or contribute to a violation of any ambient air quality standard.

VIII. 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 public generally?
		7a. Is the impact of government action direct, peculiar, and significant?
		7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
		7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

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

VIII. Environmental Assessment

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

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

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Rocky Mountain Power, LLC.
Hardin Generating Station
2575 Park Lane, Suite 200
Lafayette, CO 80026

Air Quality Permit Number: 3185-05

Preliminary Determination Issued: May 26, 2009
Department Decision Issued: June 30, 2009
Permit Final: July 16, 2009

1. *Legal Description of Site*: The facility is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana.

2. *Description of Project*: RMP operates a pulverized coal fired steam electric power generation facility known as the Hardin Generating Station, located near Hardin Montana. The proposed action is to modify existing MAQP # 3185 to authorize operation of a mercury control system including an activated carbon/sorbent handling system, storage silo and associated bin vent. The proposed project would result operation of one new emitting unit, the storage silo bin vent. Controlled emissions resulting from the proposed storage silo bin vent include particulate matter. .

3. *Objectives of Project*: The objectives of the project are to provide additional control of mercury emissions from the plant by incorporating Hg emission limitations into the existing permit in accordance with emission standards existing at ARM 17.8.771. Also the permit modification establishes a BACT-based permit limit developed upon the reasonable performance of the installed Hg control and monitoring system during the Demonstration and Optimization Period required by the Settlement Agreement. The project would result in an approximate order of magnitude reduction in allowable mercury emissions from the PC Boiler and new particulate emissions from operation of mercury control system ancillary processes.

4. *Alternatives Considered*: In addition to the proposed action, the Department also considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because RMP demonstrated compliance with all applicable rules and regulations as required for MAQP issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in MAQP #3185-05.

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

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

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

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

There would be no impacts to terrestrial and aquatic life and habitats due to facility construction from the proposed project. The RMP facility is an existing facility and all construction associated with this project has already been conducted to comply with the requirements of the Settlement Agreement. Therefore no construction activities that would disturb terrestrial or aquatic habitats is required.

Aquatic life and terrestrial habitats would realize a minor impact from the proposed project due to operation of the mercury control system because minor increases in particulate emissions would result from operation of the activated carbon storage silo that may result in some aerial deposition of particulate matter. Conversely, positive impacts to local and regional aquatic life and terrestrial habitats may be realized due to the reduction of Hg emissions from the plant that may result in a decrease in aerial deposition of mercury.

B. Water Quality, Quantity and Distribution

The proposed project would result in minor impacts to water quality, quantity, and distribution in the area because particulate emission increases from the project would be negligible but may results in additional aerial deposition particulate. Similarly local and regional water quality may improve from this project due to the decrease in allowed mercury emissions that may result in a decrease of mercury deposition in waterways local and regional waterways.

The proposed project does not include any changes in the amount of water drawn from the Bighorn River and no change to the method of water discharged from the facility. There would continue to be no direct discharge to the waters of the state of Montana. Therefore there would be no impacts to the quantity or distribution of water due to the proposed project.

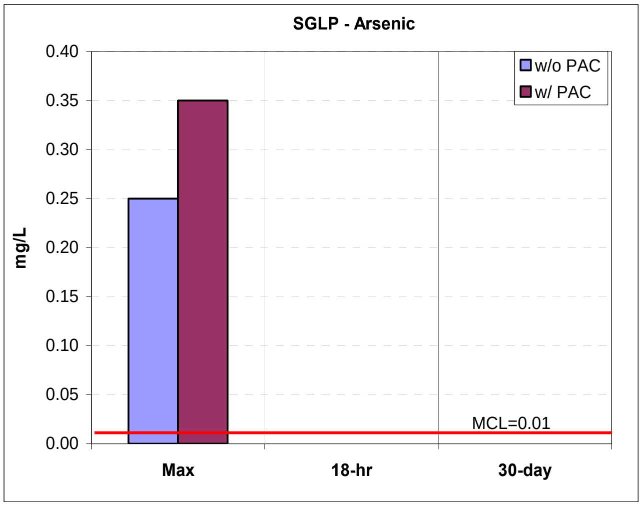
Operation of mercury control system would result in an increase in mercury, and may result in an increase in bromide, some other halogen(s), and other metal and metalloid content in the ash that is captured by the particulate control device for the PC Boiler. Ash from the facility is disposed of in a designated cell of the off-site licensed Class II landfill for the City of Hardin. The Class II landfill holds license #348 with the Department. Class II landfills are required to be designed with environmental pollution controls including mitigations for groundwater seepage and contamination. RMP provided an analysis and leachability studies performed on the ash from the Hardin Generating Station to quantify the potential groundwater impacts due to ash leaching in its application materials, as follows.

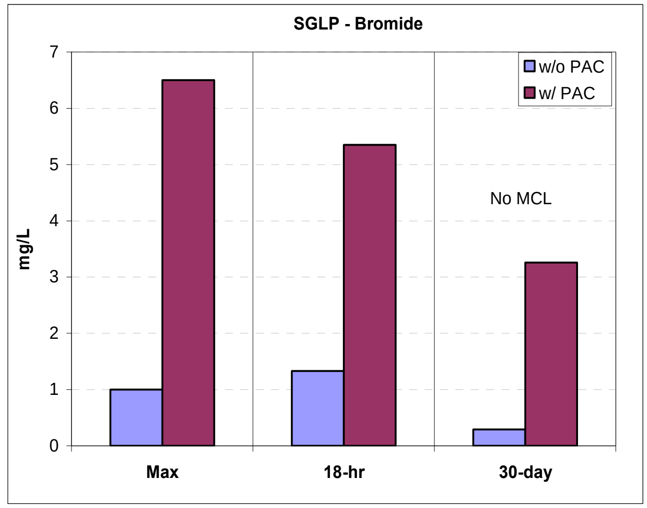
Based on analyses done as part of previous industry testing, sorbents used in mercury control are stable from the standpoint of leachability. These analyses were conducted on ash samples collected during the testing phases to determine the stability of mercury. For example, at a previous DOE test site similar in configuration to Hardin, two leaching procedures were used: Method 1311, Toxicity Characteristic Leaching Procedure (TCLP) and the Synthetic Groundwater Leaching Procedure (SGLP). The TCLP procedure measures metal mobility in a sanitary landfill. The SGLP procedure was developed by Hasset at EERC to better simulate the pH of groundwater to determine if mercury will leach from the samples under conditions designed to simulate actual field conditions. This testing, as well as thermal desorption tests to determine the thermal stability of the samples in air, showed mercury to be stable in the ash containing activated carbon.

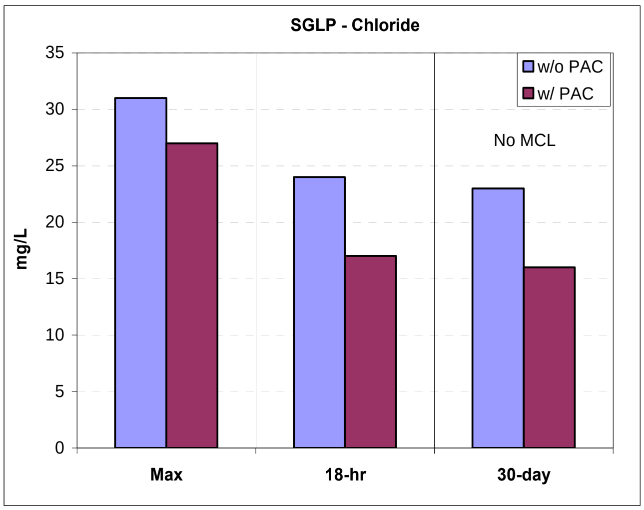
These results have also been shown on ash collected from Hardin. Ash sample from baseline and long-term tests were analyzed by the SGLP for mercury and other trace constituent stability. In the SGLP, samples are diluted 20:1 (liquid to solid ratio) and then agitated end-over-end. Samples are extracted after 18-hr and 20-days and analyzed for trace constituents. Hydration reactions that can take days or weeks to complete often incorporate trace toxins so that the 30-day concentration of these species is often lower than the 18-hr concentration.

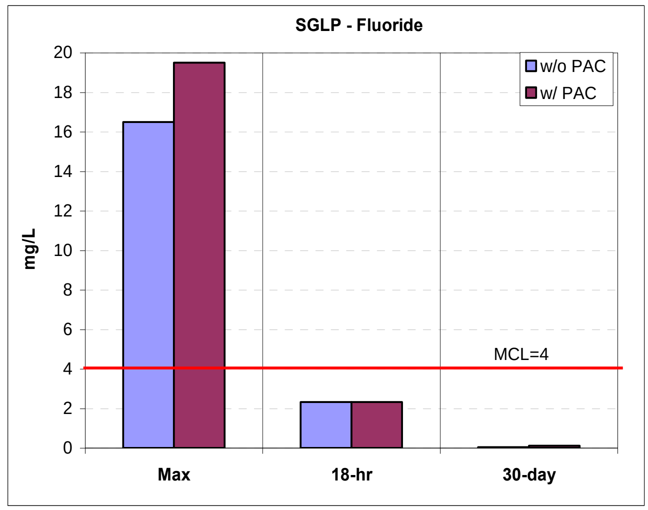
An SGLP was conducted on a baseline (no ACI) ash sample and a sample collected after months of ACI with a brominated AC. Trace materials, including bromide, chloride, fluoride, arsenic, selenium, and mercury, were measured after 18-hr and 30-days of agitation. The maximum theoretical concentration for the leachate, which assuming all of the mass of the pollutant within the ash samples was instaneously dissolved in one liter of water, was also calculated, based on the ash mass pollutant per mass ash analysis. The reported maximum concentration does not represent likely geochemical leachate processes at near neutral pH aquifer conditions, nor would the compacted pore space of the collected ash samples be equivalent to one liter. Therefore it is not representative of the maximum achievable concentration of potential ground water pollution resulting from landfill leachate. This information is presented, in part, to enable evaluation of the percentage of the available pollutant in the ash sample that dissolved at the given time increments during the SGLP test.

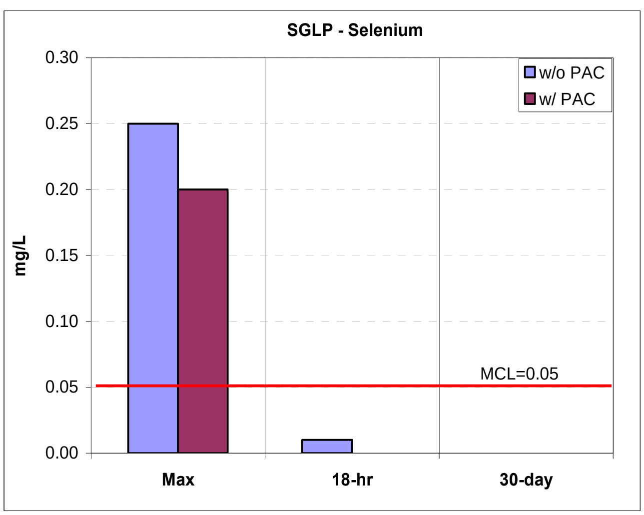
The following figure shows the SGLP results for Hardin; the leachate concentrations for the six species are compared to EPA's maximum containment level (MCL - red line) for drinking water, except for chloride and bromide that have no MCL. MCL levels are much stricter than the RCRA leaching values for sanitary landfills. In all cases, the leachate concentrations are below the MCL. The figure also shows that, although the use of a brominated AC increases the mercury concentration in the waste ash, the mercury does not leach from the sample.

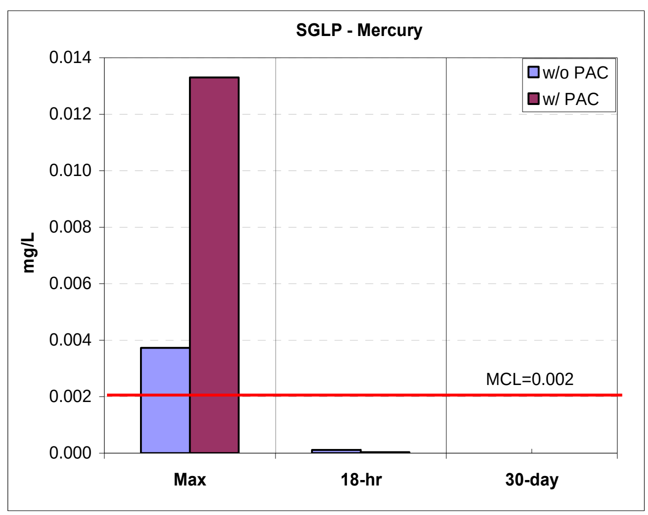










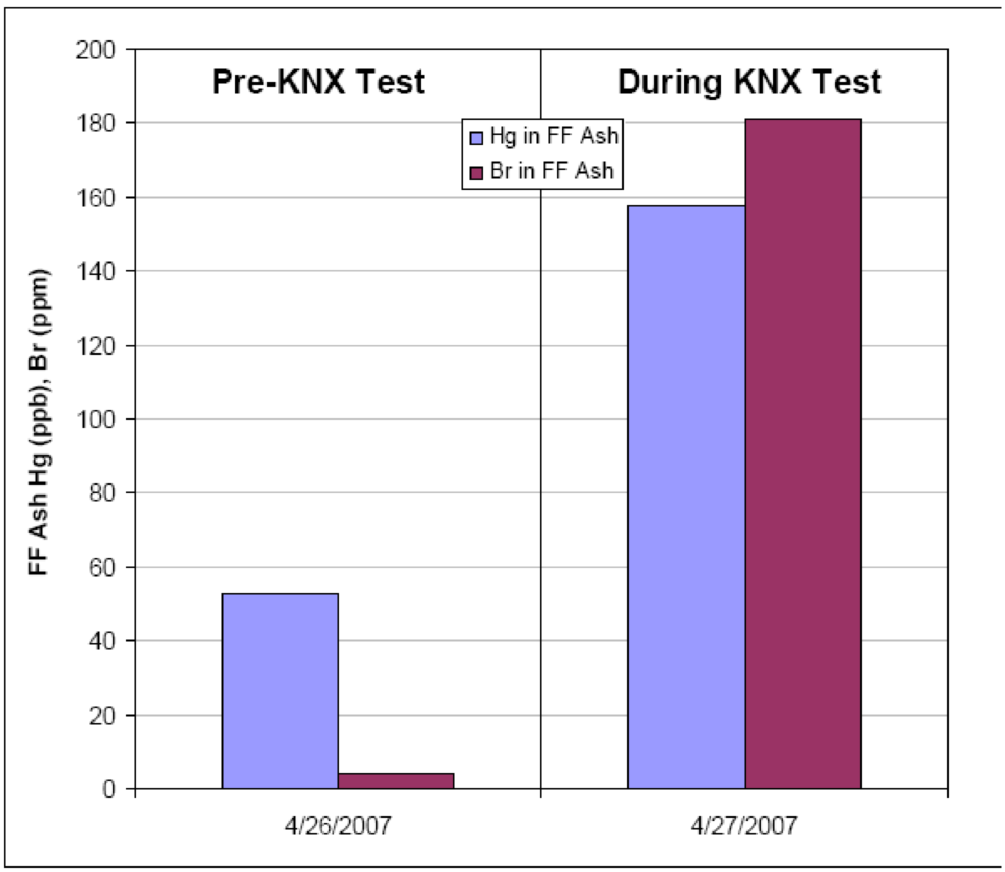


Based on the analysis and data provided above and the fact that the ash will be disposed of in a licensed Class II landfill, which inherently includes designed controls to minimize environmental impacts and pollution, the Department concludes that no, or minor impacts to ground water or surface water quality would result due to contaminants leaching from the disposed ash.

C. Geology and Soil Quality, Stability and Moisture

The impacts to the geology and soil quality, stability, and moisture from this facility would be minor because the proposed project would not change the footprint of the facility as it was previously permitted. Soil stability would not be impacted by the proposed project because the activated carbon storage silo and handling equipment has already been constructed as a condition of the Settlement Agreement. The facility would continue to not discharge any material directly to the soil in the immediate area. Some of the air emissions from the activated carbon storage silo may deposit on local soils, but that deposition would result in only a minor impact to local areas because of the air dispersion characteristics of the area (see Section 7.F of this EA).

Operation of mercury control system would result in an increase in mercury and may result in an increase in bromide, other halogen(s), metals or metalloid content in the ash that is captured by the particulate control device for the PC boiler and removed from the facility. The figure below typifies the increase in these parameters.



However, ash from the facility is disposed of in a designated cell of an existing off-site Class II landfill licensed by the City of Hardin. Class II landfills are required to be designed with environmental pollution controls. The Class II landfill holds license #348 with the Department. Therefore, no, or minor impacts to soil quality is expected associated with disposal of ash from the proposed project.

D. Vegetation Cover, Quantity, and Quality

The proposed project would result in minor impacts on the vegetative cover and quantity in the immediate area because the proposed project would not change the footprint of the facility as it was previously permitted. No new construction is proposed and the amount of resulting deposition of the air emissions from operation of the new emitting unit would be relatively small. Vegetative quality in the area may improve as the project would result in a decrease in Hg emission that may be bio-accumulated in vegetation and passed up the food chain.

E. Aesthetics

There would be no impacts to the aesthetics of the area from the proposed project because the facility is an existing facility the appearance of the plant would not change as part of the proposed project. In addition, noise and odors would remain the same as currently exist.

F. Air Quality

The proposed project would decrease allowable Hg emissions from the facility approximately an order of magnitude from previously permitted levels. These decreases would likely improve air quality. The project would also negligibly increase allowable particulate emissions from the facility by 0.000199 tpy. The proposed minor increase in particulate emissions would not be expected to have a significant impact on local or regional air quality, because previous air quality impact analyses have determined atmospheric dispersion in this area is good, no applicable standard or increment would be violated, and the proposed increase in emissions is relatively minor compared to those previously analyzed.

G. Unique Endangered, Fragile, or Limited Environmental Resources

There would be no impacts to unique, endangered or fragile environmental resources in the area from the proposed project, because the facility is an existing facility and no new construction is proposed.

In addition, the proposed project would have no impact on limited, non-renewable resources because the amount of coal and natural gas required by the facility would not change from previously analyzed levels.

H. Demands on Environmental Resource of Water, Air and Energy

As described in Section 7.B of this EA, cumulative impacts to the water resource would not change as a result of the proposed action. Therefore, there would be no impacts to the demands on the environmental resource of water from the proposed project.

As described in Section 7.F of this EA, the impact on the air resource in the area from the modification would be minor because of the amount of the proposed increase in particulate would be negligible and the project would result in a decrease in mercury emissions. There may be minor impacts on energy resources as operation of new equipment may result in a minor increase in parasitic electricity load on the plant.

I. Historical and Archaeological Sites

There would be no impacts on historical and archaeological sites because the proposed project would take place at an existing facility and would not disturb any ground.

J. Cumulative and Secondary Impacts

Overall, the cumulative impacts from the proposed project on the physical and biological aspects of the human environment would be minor. No new construction would be required for the project and no significant increase in air emissions would result from the project.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Social Structures and Mores				✓		Yes
B	Cultural Uniqueness and Diversity				✓		Yes
C	Local and State Tax Base and Tax Revenue				✓		Yes
D	Agricultural or Industrial Production			✓			Yes
E	Human Health			✓			Yes
F	Access to and Quality of Recreational and Wilderness Activities				✓		Yes
G	Quantity and Distribution of Employment				✓		Yes
H	Distribution of Population				✓		Yes
I	Demands for Government Services			✓			Yes
J	Industrial and Commercial Activity				✓		Yes
K	Locally Adopted Environmental Plans and Goals				✓		Yes
L	Cumulative and Secondary Impacts				✓		Yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed project at the existing RMP facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores); the proposed project would not change the nature or use of the site. The proposed project would be consistent with the permitted RMP facility and the former and current use of the larger area surrounding the facility (the former Holly Sugar processing plant and the current Cenex bulk storage facility). The proposed project would not affect the greater surrounding area (predominately agricultural and/or associated with the outskirts of the City of Hardin).

B. Cultural Uniqueness and Diversity

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because no physical changes are proposed at the site that was previously used for industrial activity (the Holly Sugar processing plant), and a Cenex bulk storage facility currently operates directly south of the proposed site.

As described in Section 7.F of this EA, the proposed project would not cause or contribute to a violation of ambient air quality standards. Therefore, unique cultures nearby (including the Tribe of Crow Indians and the Northern Cheyenne Tribe) would not be affected by this project. Therefore, the proposed project would cause no change in the cultural uniqueness and diversity of the area.

C. Local and State Tax Base and Tax Revenue

The proposed project would have no effect on the state tax base and tax revenue because it would not change the amount of taxes owed by the RMP facility and would not create additional employment opportunities with RMP or surrounding businesses.

D. Agricultural or Industrial Production

The impacts to agricultural and industrial production in the area from the proposed project would be minor because no physical alterations or additions would occur and the resulting deposition from air emissions would be minor.

The RMP plant site is next to a Cenex bulk storage facility and the old Holly Sugar processing plant. Therefore, the area is accustomed to industrial use.

As described in Section 7.F of the EA, the cumulative air quality impacts from this facility would be minor. However, because of the negligible changes is proposed emissions, the resulting deposition of the pollutants from the RMP facility would be minor. Overall this indicates that the impacts from the proposed modification on agricultural or industrial production would be minor.

E. Human Health

As described in Section 7.F of the EA, the impacts from this proposed project on human health would be minor increases in particulate would be greatly dispersed before humans would be exposed and the project would decrease mercury emissions. The project would not cause or contribute to a violation of the MAAQS or NAAQS. The MAQP for the facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed project would result in only a minor impact on the access to and quality of recreational and wilderness activities because the air emissions from the facility would be required to be in compliance with the NAAQS and MAAQS and would disperse before impacting the recreational areas. The recreational activities in the area are approximately ¼ to 1½ miles away. Furthermore, the RMP site is located on land previously used as an industrial site. The land use would not change. The property will continue to be private. No recreational or wilderness activities exist within the RMP property boundaries. The RMP facility would have no impact on the access to and quality of wilderness activities.

G. Quantity and Distribution of Employment

There would be no effect on the employment of the area from the proposed project because no new employees would be hired as a result of the proposed project.

H. Distribution of Population

The proposed project would have no effect on the normal population distribution in the area above the positions previously associated with the facility.

I. Demands for Government Services

Demands on government services from the proposed project would be minor because the facility would require some, but not extensive, government services. RMP would be a tax paying entity for both state and local tax bases.

The acquisition of the MAQP and compliance verification with the MAQP as well as any other state issued permits would also require minor services from the government.

J. Industrial and Commercial Activity

The proposed project would represent no change in industrial activity in the area. The proposed project would only change emission limits associated with periods of PC-Boiler and would establish permit conditions for the operation of the activated carbon/sorbent storage silo. The facility, under ideal conditions, would operate 24 hours a day and 7 days per week generating electricity. Other industrial activity in the area includes the Cenex bulk storage facility, just south of the RMP site.

K. Locally Adopted Environmental Plans and Goals

The nearest nonattainment areas with respect to air quality are the Laurel SO_2 Nonattainment Area and associated SO_2 state implementation plan area (including Billings, approximately 45 miles to the west) and the Lame Deer PM_{10} Nonattainment Area (approximately 46 miles to the east). Based on the negligible changes to in air quality from the proposed project would not significantly impact either of those nonattainment areas and therefore, would have no effect on any locally adopted environmental goals and plans associated with those two areas.

The Department is unaware of any other locally adopted environmental plans and goals that would be affected by the proposed project at the RMP facility.

L. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from the proposed project on the social and economic aspects of the human environment would be minor because the project would occur on the previously permitted RMP site, would not affect cultural and social values or recreational opportunities, would require minimal government resources, and would not increase employment above what was previously associated with the RMP facility. In addition, the proposed project would have only a minor impact on human health.

Recommendation: No Environmental Impact Statement (EIS) is required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The current permitting action is for a modification at the existing RMP facility. MAQP #3185-05 includes conditions and limitations to ensure the facility will operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System - Montana Natural Heritage Program, Montana Department of Revenue

Individuals or groups contributing to this EA: Department of Environmental Quality (Air Resources Management Bureau; Waste and Underground Tank Management Bureau; and Water Protection Bureau), Montana Historical Society – State Historic Preservation Office; Natural Resource Information System - Montana Natural Heritage Program; Department of Revenue

EA prepared by: Paul Skubinna
Date: May 18, 2009