Permit Withdrawn on 5/12/08 - Not valid for construction or operation

STATE OF MISSOURI

Matt Blunt, Governor • Doyle Childers, Director

DEPARTMENT OF NATURAL RESOURCES

www.dnr.mo.gov

MAY 1 2 2008

Mr. Brent Ross
Environmental Health & Safety Manager
Associated Electric Cooperative, Inc.
P.O. Box 754
Springfield, MO 65801

RE: Permit Number 022008-010

Dear Mr. Ross:

The Department of Natural Resources' Air Pollution Control Program received your request, April 17, 2008 letter, to rescind permit number 022008-010. As you are aware, the department issued this permit to Associated Electric Cooperative, Inc. (AECI) on February 22, 2008 to construct a coal fired power plant in Norborne, Missouri. In your letter you state AECI no longer intends to build this power plant.

At your request, the department has withdrawn the permit and considers this permit no longer valid. If AECI decides to build any power plants in the future, a new air permit application and permit, and all the associated requirements, are required.

If you should have any questions concerning this letter, please feel contact me at the department's Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102, or by phone at (573) 751-4817. Thank you for your attention to this matter.

Sincerely,

AIR POLLUTION CONTROL PROGRAM

James L Kavanaugh

James L. Kavanaugh
Director

JLK:kml

c: Mr. Steve Feeler, Compliance/Enforcement Section
Northeast Regional Office
PAMS File: 2006-01-066

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Permit Withdrawn on 5/12/08 - Not valid for construction or operation

STATE OF MISSOURI

DEPARTMENT OF NATURAL RESOURCES

MISSOURI AIR CONSERVATION COMMISSION

PERMIT TO CONSTRUCT

Under the authority of RSMo 643 and the Federal Clean Air Act the applicant is authorized to construct the air contaminant source(s) described below, in accordance with the laws, rules and conditions as set forth herein.

Permit Number: 022008-010 Project Number: 2006-01-066

Parent Company: Associated Electric Cooperative, Inc

Parent Company Address: P.O. Box 754, Springfield, MO 65801

Installation Name: Associated Electric Cooperative, Inc. Norborne Power Plant

Installation Address: 30239 JJ Hwy., Norborne, MO 64668

Location Information: Carroll County, S8, 17, 20, T52N, R25W

Application for Authority to Construct was made for a new supercritical pulverized coal-fired boiler with related material handling and pollution control equipment and a steam turbine generator with a net electrical output of 689 Megawatts (MW) [780 MW gross output]. This review was conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*..

☐ Standard Conditions (on reverse) are applicable to this permit.

☑ Standard Conditions (on reverse) and Special Conditions are applicable to this permit.

FEB 2 2 2008

EFFECTIVE DATE

DIRECTOR OR DESIGNEE
DEPARTMENT OF NATURAL RESOURCES

Permit Withdrawn on 5/12/08 - Not valid for construction or operation

STANDARD CONDITIONS:

Permission to construct may be revoked if you fail to begin construction or modification within 18 months from the effective date of this permit. Permittee should notify the Air Pollution Control Program if construction or modification is not started within eighteen months after the effective date of this permit, or if construction or modification is suspended for one year or more.

You will be in violation of 10 CSR 10-6.060 if you fail to adhere to the specifications and conditions listed in your application, this permit and the project review. In the event that there is a discrepancy between the permit application and this permit, the conditions of this permit shall take precedence. Specifically, all air contaminant control devises shall be operated and maintained as specified in the application, associated plans and specifications.

You must notify the department's Air Pollution Control Program of the anticipated date of start up of this (these) air contaminant sources(s). The information must be made available not more than 60 days but at least 30 days in advance of this date. Also, you must notify the Department of Natural Resources Regional office responsible for the area within which you are located with 15 days after the actual start up of this (these) air contaminant source(s).

A copy of this permit and permit review shall be kept at the installation address and shall be made available to Department of Natural Resources' personnel upon request.

You may appeal this permit or any of the listed special conditions to the Administrative Hearing Commission (AHC), P.O. Box 1557, Jefferson City, MO 65102, as provided in RSMo 643.075.6 and 621.250.3. If you choose to appeal, you must file a petition with the AHC within 30 days after the date this decision was mailed or the date it was delivered, whichever date was earlier. If any such petition is sent by registered mail or certified mail, it will be deemed filed on the date it is mailed. If it is sent by any method other than registered mail or certified mail, it will be deemed filed on the date it is received by the AHC.

If you choose not to appeal, this certificate, the project review and your application and associated correspondence constitutes your permit to construct. The permit allows you to construct and operate your air contaminant sources(s), but in no way relieves you of your obligation to comply with all applicable provisions of the Missouri Air Conservation Law, regulations of the Missouri Department of Natural Resources and other applicable federal, state and local laws and ordinances.

The Air Pollution Control Program invites your questions regarding this air pollution permit. Please contact the Construction Permit Unit at (573) 751-4817. If you prefer to write, please address your correspondence to the Missouri Department of Natural Resources, Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102-0176, attention: Construction Permit Unit.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

The special conditions listed in this permit were included based on the authority granted the Missouri Air Pollution Control Program by the Missouri Air Conservation Law (specifically 643.075) and by the Missouri Rules listed in Title 10, Division 10 of the Code of State Regulations (specifically 10 CSR 10-6.060). For specific details regarding conditions, see 10 CSR 10-6.060 paragraph (12)(A)10. "Conditions required by permitting authority."

Associated Electric Cooperative, Inc. Norborne Power Plant
Carroll County, S8, 17, 20, T52N, R25W

1. Specifications, Operating Limits and Emission Limits for Main Boiler (CS-01)
   A. The main boiler shall be fired with low sulfur, subbituminous coal (less than 0.62 pound of sulfur per million British Thermal Units [lb/MMBTU]) as the primary fuel. Heat input to the main boiler shall not exceed 6,872 million British Thermal Units per hour (MMBTU/hr).

   B. The main boiler shall not use more than 500,000 gallons per year of No. 2 fuel oil except as follows. For the first twelve month (12) months starting the day of the first fire, the main boiler shall not use more than 650,000 gallons per year of No. 2 fuel oil. The sulfur content of the fuel oil shall not exceed 0.05 percent sulfur by weight at any time. The fuel oil shall be used during periods of startup, flame stabilization, or emissions testing only.

   C. The main boiler shall use no other fuels other than low sulfur, subbituminous coal and No. 2 fuel oil without receiving prior written authorization from the Air Pollution Control Program.

   D. Activated carbon injection (or injection of an equivalent absorbent) shall be used to reduce mercury emissions to meet, at a minimum, the New Source Performance Standards (NSPS), Subpart Da emission rates limit.

   E. The following controls will be utilized to reduce emissions from the main boiler (CS-01). Associated Electric Cooperative, Inc. Norborne Power Plant shall install and effectively operate:
      1) Selective Catalytic Reduction (SCR), low-nitrogen oxide burners (LNB) and overfire air (OFA) for the control of nitrogen oxide (NO_X) emissions.
      2) Dry Flue Gas Desulfurization (DFGD) for the control of sulfur dioxide (SO_2) emissions.
      3) Fabric filtration system (baghouse(s)) for the control of filterable particulate matter less than ten (10) microns in diameter (filterable PM_{10}) and filterable particulate matter (PM) emissions.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

4) Good combustion practices for the control of carbon monoxide (CO) and volatile organic compound (VOC) emissions.

5) DFGD and fabric filtration system for emissions control of condensable PM_{10} (CPM), sulfuric acid mist, and hydrogen fluoride (HF).

F. The following BACT emission limits apply to the main boiler. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission limits:

1) NO_X
   a) 0.065 lb/MMBTU, exclusive of start-up and shutdown, based on a 30-day rolling average.
   b) 0.05 lb/MMBTU, exclusive of start-up and shutdown, based on a 12-month rolling average.
   c) 1,535 tons per a 12-month rolling average, inclusive of start-up and shutdown.

2) SO_2
   a) 0.08 lb/MMBTU, when fuel sulfur content is greater than or equal to 0.40 weight (wt.) percent, exclusive of start-up and shutdown, based on a 30-day rolling average.
   b) 0.074 lb/MMBTU, when fuel sulfur content is greater than 0.20 wt. percent but less than 0.40 wt. percent, exclusive of start-up and shutdown, based on a 30-day rolling average.
   c) 0.07 lb/MMBTU, when fuel sulfur content is less than or equal to 0.20 wt percent, exclusive of start-up and shutdown, based on a 30-day rolling average.
   d) The fuel sulfur content as determined in special condition 11.A shall be used to establish the SO_2 limit for that day.
   e) 2,408 tons per a 12-month rolling average, inclusive of start-up and shutdown.

3) PM and PM_{10}
   a) Filterable PM_{10} – 0.012 lb/MMBTU, exclusive of start-up and shutdown, based on a 3-hour rolling average.
   b) Filterable PM – 0.013 lb/MMBTU, exclusive of start-up and shutdown, based on a 3-hour rolling average.
   c) Total PM_{10} – 0.018 lb/MMBTU, exclusive of start-up and shutdown, based on a 3-hour rolling average. This limit includes both filterable and condensable PM_{10}..
   d) Total PM_{10} – 123.7 pounds per hour (lb/hr), inclusive of start-up and shutdown, based on a 24-hour period. This limit includes both filterable and condensable PM_{10}.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

4) CO – 0.15 lb/MMBTU, inclusive of start-up and shutdown, based on a 30-day rolling average.
5) VOC – 0.0036 lb/MMBTU, inclusive of start-up and shutdown, test method average.
6) SAM – 0.0038 lb/MMBTU, inclusive of start-up and shutdown, test method average.

G. The following additional emission limits apply to the main boiler. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission rate limits. Note: The following emission limits are inclusive of start-up and shutdown.
1) SO_2
a) 1,133.91 lb/hr, 3-hour block average.
b) 824.62 lb/hr, 24-hr rolling average.
2) CO
a) 1,374.4 lb/hr, 1-hour rolling average.
b) 1,030.8 lb/hr, 8-hour rolling average.
3) Lead (Pb) – 0.034 lb/hr, test method average.
4) Hydrogen fluoride (HF) – 7.3 lb/hr, test method average.
5) Beryllium – 0.0015 lb/hr, test method average.
6) Opacity – 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent.

2. Specifications, Operating Limits and Emission Limits for an Auxiliary Boiler (CS-02)
A. The auxiliary boiler shall be fired with No. 2 fuel oil. The sulfur content of the fuel oil shall not exceed 0.05 percent sulfur by weight. No other fuels shall be used without receiving prior written authorization from the Air Pollution Control Program.

B. Heat input to the auxiliary boiler shall not exceed 374.9 MMBTU/hr or 2.678 - 1000 gallons per hour (Mgal/hr).

C. The auxiliary boiler shall not be operated more than 2,190 hours per calendar year and shall be equipped with a non-resettable meter.

D. The following controls will be utilized to reduce emissions from the auxiliary boiler. Associated Electric Cooperative, Inc. Norborne Power Plant shall install and effectively operate:
1) LNB and flue gas recirculation (FGR) for the control of NO_X emissions.
2) Good combustion practices and FGR for the control of PM_{10}

emissions.

3) Good combustion practices for the control of CO and VOC emissions.

E. The following BACT emission limits apply to the auxiliary boiler. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission limits:
1) NO_X - 0.10 lb/MMBTU, test method average.
2) SO_2 - 0.0524 lb/MMBTU, test method average.
3) SAM – 0.004 lb/MMBTU, test method average.
4) Filterable PM_{10} – 0.007 lb/MMBTU, test method average.
5) Filterable PM – 0.014 lb/MMBTU, test method average.
6) Total PM_{10} – 0.016 lb/MMBTU, test method average.
7) CO - 0.08 lb/MMBTU, test method average.
8) VOC – 0.005 lb/MMBTU, test method average.

3. Specifications, Operating Limits and Emission Limits for an Emergency Generator (CS-03)

A. The emergency generator shall be fired with No. 2 fuel oil. The sulfur content of the fuel oil shall not exceed 0.05 percent sulfur by weight. No other fuels shall be used without receiving prior written authorization from the Air Pollution Control Program.

B. Heat input to the emergency generator shall not exceed 18.25 MMBTU/hr or 0.1294 Mgal/hr.

C. The emergency generator shall not be operated more than 500 hours per calendar year and shall be equipped with a non-resettable meter.

D. Associated Electric Cooperative, Inc. Norborne Power Plant shall meet the requirements of the applicable CI ICE standards and install and effectively operate combustion controls in order to reduce emissions below these standards.

E. The following BACT emission limits apply to the emergency generator. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission limits:
1) NO_X plus non-methane hydrocarbons (NMHC) - 1.364 lb/MMBTU, test method average.
2) SO_2 - 0.052 lb/MMBTU, test method average.
3) Filterable PM_{10} – 0.035 lb/MMBTU, test method average.
4) CO - 0.75 lb/MMBTU, test method average.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

5) SAM – 0.004 lb/MMBTU, test method average.

4. Specifications, Operating Limits and Emission Limits for a Fire Water Pump (CS-04) and Fire Water Booster Pump (CS-05)

A. The fire water pump and fire water booster pump shall be fired with No. 2 fuel oil. The sulfur content of the fuel oil shall not exceed 0.05 percent sulfur by weight. No other fuels shall be used without receiving prior written authorization from the Air Pollution Control Program.

B. Heat input to the fire water pump shall not exceed 3.33 MMBTU/hr or 0.0236 Mgal/hr.

C. Heat input to the fire water booster pump shall not exceed 1.08 MMBTU/hr or 0.0077 Mgal/hr.

D. The fire water pump and fire water booster pump shall not be operated more than 500 hours each per calendar year and both shall be equipped with a non-resettable meter.

E. Associated Electric Cooperative, Inc. Norborne Power Plant shall meet the requirements of the applicable CI ICE standards and install and effectively operate combustion controls in order to reduce emissions below these standards.

F. The following BACT emission limits apply to the fire water pump. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission limits:

1) NO_X plus NMHC - 0.8580 lb/MMBTU, test method average.
2) SO_2 - 0.0524 lb/MMBTU, test method average.
3) Filterable PM_{10} – 0.0429 lb/MMBTU, test method average.
4) CO - 0.7436 lb/MMBTU, test method average.
5) SAM – 0.004 lb/MMBTU, test method average.

G. The following BACT emission limits apply to the fire water booster pump. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following emission limits:

1) NO_X plus NMHC- 3.001 lb/MMBTU, test method average.
2) SO_2 - 0.0524 lb/MMBTU, test method average.
3) Filterable PM_{10} – 0.1715 lb/MMBTU, test method average.
4) CO - 1.0574 lb/MMBTU, test method average.
5) SAM – 0.004 lb/MMBTU, test method average.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

5. Specifications, Operating Limits and Emission Limits for Cooling Towers

   A. BACT for the cooling towers is high efficiency drift eliminators. The cooling towers shall be equipped with high efficiency drift eliminators that are designed to reduce drift to less than 0.0005 percent of the circulating water flow rate. Verification of drift loss shall be by manufacturer's guaranteed drift loss and shall be kept on site and made readily available to Department of Natural Resources' employees upon request.

   B. The cooling tower(s) shall be operated and maintained in accordance with the manufacturer's specifications. Manufacturer's specifications shall be kept on site and made readily available to Department of Natural Resources' employees.

   C. The cooling water circulation rate shall not exceed 22.5 million gallons per hour on a daily average.

   D. The total dissolved solids (TDS) concentration in the circulated cooling water shall not exceed a TDS concentration of 5,000 parts per million (ppm). A TDS sample of the circulated cooling water shall be collected daily to verify the TDS concentration. Following six (6) consecutive months of compliance, sampling shall be allowed on a bi-weekly basis. If at any time, non-compliance is shown, sampling shall return to a daily basis until six (6) months of further compliance is demonstrated.

6. Specifications and Operating Limits for Haul Roads

   A. Associated Electric Cooperative, Inc. Norborne Power Plant shall not exceed the following maximum trip per day limits. If any parameters affecting the emission factors for the haul roads change, these daily limits are subject to amendment. The parameters affecting the haul road emission factors include the length of the haul road, surface material silt content, and mean vehicle weight.

   Table 1: Daily Truck Haul Frequency

Description	**Limit – Trips/Day**
Solid waste to landfill	33
Lime trucks to plant	5
Activated carbon trucks to plant	1
Bottom ash to offsite	7

   B. The following BACT controls and practices will be utilized to reduce emissions from the paved and unpaved haul roads.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

C. Paved Roads

1) Associated Electric Cooperative, Inc. Norborne Power Plant shall pave the lime and activated carbon haul roads (HR1 and HR2) up to the edge of haul road three (HR3) with materials such as asphalt, concrete, and/or other material after receiving approval from the Program. The pavement will be applied in accordance with industry standards for such pavement so as to achieve control of fugitive emissions while the plant is operating.

2) Maintenance and/or repair of the road surface will be conducted as necessary to ensure that the physical integrity of the pavement is adequate to achieve control of fugitive emissions from these roads.

3) Associated Electric Cooperative, Inc. Norborne Power Plant shall periodically water, wash and/or otherwise clean all of the paved portions of the haul roads as necessary to achieve control of fugitive emissions from these roads.

D. Unpaved Roads

1) Associated Electric Cooperative, Inc. Norborne Power Plant shall control emissions from the unpaved waste haul road (HR-3) by **either** documented watering or the application of chemical dust suppressant as specified below.

2) Chemical Dust Suppressant

a) The suppressant (such as magnesium chloride, calcium chloride, lignosulfonates, etc.) shall be applied in accordance with the manufacturer's suggested application rate and re-applied as necessary to achieve control of fugitive emissions from the road.

b) Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the time, date, and the amount of material applied for each application of chemical dust suppressant agent on the road.

3) Documented Watering

a) Documented watering will be applied in accordance with a recommended application rate of 100 gallons per day per 1,000 square feet of unpaved/untreated surface area of haul roads as necessary to achieve control of fugitive emissions from these areas.

b) Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain a log that documents daily water applications. This log shall include, but is not limited to, date and volumes (e.g., number of tanker applications and/or total gallons used) of water application. The log shall also record

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

rationale for not applying water on day(s) the areas are in use (e.g., meteorological situations, precipitation events, freezing, etc.).

c) Meteorological precipitation of any kind, (e.g. a quarter inch or more rainfall, sleet, snow, and/or freeze thaw conditions) which is sufficient in the amount or condition to achieve control of fugitive emissions from these areas while the areas are in use, may be substituted for documented water application until such time as conditions warrant applying documented watering.

d) Watering may also be suspended when the ground is frozen, during periods of freezing conditions when watering would be inadvisable for traffic safety reasons, or when there will be no traffic on the roads. Associated Electric Cooperative, Inc. Norborne Power Plant shall record a brief description of such events in the same log as the documented watering.

7. Specifications for Storage Piles Vehicular Activity Areas

A. The coal storage pile footprint area (active and in-active storage) shall not exceed 13.3 acres.

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall utilize the following BACT controls and practices in order to reduce emissions from the storage piles and the solid waste landfill.

C. Chemical Binder Use at TP-8A/B

1) The chemical binder shall be applied at the stockout conveyors C-2 and C-3 to all coal that will be loaded into the stockpiles.

2) The chemical binder shall be applied in accordance with the manufacturer's suggested application rate and re-applied, as necessary to achieve control of emissions from the coal while it remains stockpiled.

3) Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the initial amount of chemical binder applied to each load of coal unloaded to the coal piles and the amount of chemical binder subsequently re-applied.

D. Vehicular Activity Areas

1) Particulate emissions from vehicular activity areas of the active and reserve coal stockpiles and the solid waste landfill shall be controlled by the use of documented watering or chemical surfactant usage. The vehicular activity area includes all areas

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

around and between the active piles that could be used during coal transfer between the piles or within a single pile.

2) Chemical Dust Suppressant
   a) The suppressant (such as magnesium chloride, calcium chloride, lignosulfonates, etc.) shall be applied in accordance with the manufacturer’s suggested application rate and re-applied as necessary to achieve control of fugitive emissions from these areas.
   b) Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the time, date, and the amount of material applied for each application of chemical dust suppressant agent on these areas.
3) Documented Watering
   a) Documented watering will be applied in accordance with a recommended application rate of 100 gallons per day per 1,000 square feet of unpaved/untreated surface area of vehicular activity area as necessary to achieve control of fugitive emissions from these areas.
   b) Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain a log that documents daily water applications. This log shall include, but is not limited to, date and volumes (e.g., number of tanker applications and/or total gallons used) of water application. The log shall also record rationale for not applying water on day(s) the areas are in use (e.g., meteorological situations, precipitation events, freezing, etc.).
   c) Meteorological precipitation of any kind, (e.g. a quarter inch or more rainfall, sleet, snow, and/or freeze thaw conditions) which is sufficient in the amount or condition to achieve control of fugitive emissions from these areas while the areas are in use, may be substituted for documented water application until such time as conditions warrant applying documented watering.
   d) Watering may also be suspended when the ground is frozen, during periods of freezing conditions when watering would be inadvisable for traffic safety reasons, or when there will be no traffic on the roads. Associated Electric Cooperative, Inc. Norborne Power Plant shall record a brief description of such events in the same log as the documented watering.

8. Specifications, Operating Limits and Emission Limits for Material Handling
   A. The rail car unloading rate shall not exceed 4,000 tons of coal per hour,

averaged over a 24-hour period.

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall utilize the following BACT controls and practices in order to reduce emissions from the material handling processes.

C. Railcar Unloading
Associated Electric Cooperative, Inc. Norborne Power Plant shall partially enclose and vent PM_{10} emissions from railcar unloading to baghouses (EP-2A and EP-2B).

D. Baghouses
1) Associated Electric Cooperative, Inc. Norborne Power Plant shall enclose and vent each PM_{10} point source listed in Special Condition 8.C.2 using baghouses. The enclosure of the emissions units shall be constructed and maintained such that no visible emissions [zero percent (0%) opacity from the enclosure] are allowed to occur from these sources except through the gases exiting from the baghouses.
2) Point Sources Requiring Baghouses
a) Coal transfers from the belt feeders (BF-1A, BF-1B, or BF-1C) and CC-1 (EP-2A, EP-2B),
b) Coal transfer from coal hopper to conveyor C-4 or C-5 (EP-29),
c) Coal crusher house emissions (EP-28A and EP-28B) consisting of:
(1) Transfer from conveyor C-4 or C-5 to surge bins,
(2) Transfer from surge bins to posimetric feeders,
(3) Coal crushers, and
(4) Transfer from crushers to conveyor C-6,
d) Coal tripper house emissions (EP-26) resulting from 2 conveyor transfers,
e) Waste Ash Storage Silo (EP-30),
f) Recycled Ash Storage Silo (EP-33),
g) Lime Storage Silo (EP-39), and
h) Activated Carbon Storage Silo (EP-41).
3) Associated Electric Cooperative, Inc. Norborne Power Plant shall not emit more than 0.005 grains per dry standard cubic foot (gr/dscf) of filterable PM_{10} from any baghouse listed in Special Condition 8.C.2).

E. Vacuum Exhausters

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

1) Associated Electric Cooperative, Inc. Norborne Power Plant shall vent the following PM_{10} point sources using vacuum exhausters, in addition to the baghouses listed above.
   a) Waste Ash Storage Silo (any combination of two (2): EP-32A, -32B, or -32C) and
   b) Recycled Ash Storage Silo (any combination of two (2): EP-35A, -35B or -35C).
2) Associated Electric Cooperative, Inc. Norborne Power Plant shall not emit more than 0.005 grains per dry standard cubic foot (gr/dscf) of filterable PM_{10} from any of the exhausters listed in Special Condition 8.D.1).

F. Chemical Binder Use at TP-1
1) Chemical binder shall be applied at the elevating conveyor C-1 to all coal delivered to the installation.
2) The chemical binder shall be applied in accordance with the manufacturer's suggested application rate to achieve control of emissions from the coal during handling.
3) Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the amount of material applied on each coal delivery shipment and the corresponding amount of coal received.

G. Restriction on Use of Ventilation Exhaust Fan

The ventilation exhaust fan (EP-5) may be operated only during periods of system maintenance to prevent emissions of PM_{10} from the underground tunnel. System maintenance shall not occur at any time that railcar unloading is taking place, or when conveyors CC-1 or C-1 are in operation.

H. Landfill Dozer Limited Hours of Operation

Associated Electric Cooperative, Inc. Norborne Power Plant shall operate the landfill dozer only between the hours of 5:00 a.m. and 9:00 p.m. daily.

I. Water Addition

Associated Electric Cooperative, Inc. Norborne Power Plant shall condition all waste ash and bottom ash loaded for transport to the landfill (TP-31 and TP-36) to at least 27 percent moisture content. Testing of moisture content shall be conducted on a monthly basis.

9. Continuous Emission Monitoring System (CEMS)/Continuous Opacity Monitoring System (COMS) – Main Boiler

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

A. Associated Electric Cooperative, Inc. Norborne Power Plant shall install, certify, operate, calibrate, test and maintain CEMS for $NO_{X,}$ $SO_{2,}$ CO, PM, and any necessary auxiliary monitoring equipment in accordance with all applicable regulations. If there are conflicting regulatory requirements, the more stringent shall apply.

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall install and operate a data acquisition and handling system to calculate emissions in terms of the emission limitations specified in this permit.

C. Compliance with the $NO_{X,}$ SO_2 and CO emission limits given in Special Condition 1.F.1), 1.F.2), 1.F.4), 1.G.1) and 1.G.2) for the pulverized coal boiler shall be demonstrated through the use of the required CEMS.

D. Compliance with the opacity limit given in Special Condition 1.G.6) for the pulverized coal boiler shall be demonstrated through the use of COMS or the required PM CEMS as per the provisions of 40 CFR Part 60 Subpart Da, *Standards of Performance for Electric Utility Steam Generating Untis for Which Construction is Commenced After Septemeber 18, 1978*. In the event a COMS is installed, Associated Electric Cooperative, Inc. Norborne Power Plant shall install, certify, operate, calibrate, test and maintain COMS for opacity in accordance with all applicable regulations

E. Compliance with the total PM_{10}, filterable PM_{10} and filterable PM emission limits given in Special Condition 1.F.3) for the pulverized coal boiler shall be demonstrated by use of the required PM CEMS and stack testing. The data gathered from the CEMS shall be adjusted as follows:

1) Total $PM_{10} = PM_{CEM} + CPM - PM_{>10}$

2) Filterable $PM_{10} = PM_{CEM} - PM_{>10}$

Where,
PM_{CEM} = reported value from the particulate matter CEMS.
= Filterable particulate matter.
CPM = condensable particulate matter, from the stack test data.
$PM_{>10}$ = mass fraction of particulate matter greater than ten microns in diameter (from stack test data) multiplied by PM_{CEM}.

10. Compliance Testing

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

A. Initial performance testing shall be conducted in order to verify compliance with special conditions 1.F.5) and 1.F.6), 1.G.3) through 1.G.5), 2.E.1) through 2.E.8), 3.E.1) through 3.E.5), 4.F.1) through 4.F.5), and 4.G.1) through 4.G.5). .

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall conduct stack testing of the baghouses listed below in order to verify compliance with special condition 8.C.3).
   1) One of two baghouses controlling emissions from the rotary car dumper and coal transfers at belt feeders (BF-1A, BF-1B, and BF-1C) and CC-1 (EP2A or EP-2B),
   2) One of two baghouses at coal crusher house (EP-28A or EP-28B)
   3) Baghouse at Waste Ash Storage Silo (EP-30)
   4) Baghouse at Recycled Ash Storage Silo (EP-33),
   5) Baghouse at Lime Storage Silo (EP-39), and
   6) Activated Carbon Storage Silo (EP-41)

C. Associated Electric Cooperative, Inc. Norborne Power Plant shall conduct stack testing of at least one of the three vacuum exhausters associated with EP-32 and EP-35 in order to verify compliance with special condition 8.D.).

D. The performance/certification tests shall be performed within 60 days of achieving the maximum production rate, but no later than 180 days after initial startup. Following the initial performance testing, Associated Electric Cooperative, Inc. Norborne Power Plant shall conduct the stack testing in order to verify continued compliance of special conditions 1.F)3)a), 1.F)3)c), 1.F.5), 1.F.6), and 1.G.3) through 1.G.5) every two (2) years.

E. In lieu of performance testing for hydrogen fluoride, beryllium, and/or lead every two years as required per Special Condition 10.D, Associated Electric Cooperative, Inc. Norborne Power Plant may establish an emissions profile for each pollutant. To establish the emission profile based upon coal sampling and associated stack testing, a minimum of three (3) consecutive stacks tests as conducted in accordance to special condition 10.D is required. This profile and a current coal analysis may be used to show continued compliance of special condition 1.G.3) through 1.G.5).

F. The date on which performance/certification tests are conducted and the date on which the initial and subsequent stack tests are conducted shall be pre-arranged with the Air Pollution Control Program a minimum of 30

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

days prior to the proposed test so that a pretest meeting may be arranged if necessary, and to assure that the test date is acceptable for an observer to be present. A completed Proposed Test Plan form (copy enclosed) may serve the purpose of notification and must be approved by the Air Pollution Control Program prior to conducting the required emission testing.

G. Two (2) copies of a written report of the performance test results shall be submitted to the Director of the Air Pollution Control Program within 30 days of completion of any required testing. The report must include legible copies of the raw data sheets, analytical instrument laboratory data, and complete sample calculations from the required EPA method for at least one (1) sample run.

11. Determination of Fuel Sulfur Content

A. Coal Sampling Procedures to Determine Fuel Sulfur Content

1) Fuel sulfur content shall be determined by daily fuel sampling averaged on a 30-day basis. The coal sample shall be taken from the tripper conveyor C-7. Analysis of samples taken on Saturday and Sunday shall be performed on the following Monday.

2) After the first twelve months of operation, Associated Electric Cooperative, Inc. Norborne Power Plant may submit a variability analysis on the sulfur content to Director of the Air Pollution Control Program. Upon approval by the Director, periodic sampling may be used in place of every day sampling. Periodic sample will consist of a single sample taken to represent a six-day or less interval of the thirty-day average.

3) For this special condition, a deviation is considered to be two consecutive samples whose coal sulfur analysis reveals percent-by-weight data that differ by more than plus or minus 0.04%. In the event of a deviation, periodic sampling will be replaced by daily samples until there are 30 days of sampling with no deviations.

4) For daily and periodic (i.e. 1 sample for every 6 days) sampling, the facility will report any changes from the sampling frequency and will maintain fuel data availability at or above 80% for each running 30-day average.

5) Daily samples that are missed, lost, or otherwise corrupted during testing will be substituted with the average of the previous quality assured daily sample and the following quality assured daily sample.

6) Periodic samples that are missed, lost, or otherwise corrupted during testing will be re-sampled and tested in duplicate within the 6

day period.

B. Fuel Oil
Associated Electric Cooperative, Inc. Norborne Power Plant shall analyze the sulfur content of the fuel oil by taking a weekly representative sample of fuel oil from the fuel oil storage tanks or by using analytical results for each shipment from the fuel vendor. In leiu of this, the monthly report entitled *Division of Weights and Measures Official Test Report* from the Department of Agriculture or other delegated agency in charge of fuel terminal oversight may be used.

12. Baghouses

A. All baghouses shall be operated and maintained in accordance with the manufacturer's specifications. The baghouse shall be equipped with a gauge or meter, which indicates pressure drop across the control device. These gauges or meters shall be located such that the Department of Natural Resources' employees may easily observe them. Replacement filters for the baghouses shall be kept on hand at all times. The bags shall be made of fibers appropriate for operating conditions expected to occur (i.e. temperature limits, acidic and alkali resistance, and abrasion resistance).

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall monitor and record the operating pressure drop across the baghouses at least once every 24 hours. The operating pressure drop shall be maintained within the design conditions specified by the manufacturer's performance warranty.

C. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operating and maintenance log for the baghouses which shall include the following:
   1) Incidents of malfunction, with impact on emissions, duration of event, probable cause, and corrective actions; and
   2) Maintenance activities, with inspection schedule, repair actions, and replacements, etc.

13. Vapor Phase Mercury
The Court of Appeals recently vacated and remanded to EPA for reconsideration the Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units (CAMR), 70 Fed. Reg. 28,606 (May 18, 2005). *See New Jersey v. Environmental Protection Agency,* ___ F.3d ___, 2008 WL 341338 (D.C. Cir. Feb. 8, 2008). At this time, the court's mandate has not been

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

issued and the decision is not yet final and effective. In the event that the Clean Air Act Mercury Rule (CAMR) is vacated permanently, AECI is required to take appropriate action, as required by EPA, or AECI must complete a Section (9) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs) as stated in 10 CSR 10-6.060(9). AECI is required to act within 90 days of the court's final mandate.

14. Post-Construction Ozone Monitoring

    A. Associated Electric Cooperative, Inc. Norborne Power Plant shall conduct post-construction ambient air quality monitoring for ozone for at least the first full ozone season (April 1st through October 31st) that the new plant commences normal operations. Dependent on the concentrations of ozone observed, Associated Electric Cooperative, Inc. Norborne Power Plant may be required to continue ozone ambient air quality monitoring for a second full ozone season. If there are no exceedances of the ozone standards after the first full ozone season, the second year will not be required.

    B. Within 60 days of permit issuance, Associated Electric Cooperative, Inc. Norborne Power Plant shall submit a Quality Assurance Project Plan (QAPP) describing the methods and procedures for conducting the required ambient air monitoring.

    C. Associated Electric Cooperative, Inc. Norborne Power Plant shall resolve or address, to the Air Pollution Control Program's satisfaction, any Air Pollution Control Program recommendations on the QAPP for the ozone ambient air monitoring within the time frames indicated in any such comments. A completed QAPP must be approved by the Director of the Air Pollution Control Program prior to conducting the required ambient air monitoring.

    D. Associated Electric Cooperative, Inc. Norborne Power Plant shall submit the results of the ambient monitoring to the Air Pollution Control Program based on the reporting schedule indicated in the QAPP.

    E. Within 60 days of completion of the first full, post-construction, ozone season. Associated Electric Cooperative, Inc. Norborne Power Plant shall submit to the Air Pollution Control Program plans for second full season ozone monitoring or a request for discontinuation of ozone monitoring. Associated Electric Cooperative, Inc. Norborne Power Plant must receive written authorization from the Air Pollution Control Program to discontinue ozone monitoring.

15. Record Keeping

    A. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain a record of emission verification data for all applicable pieces of equipment including CEMs data.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain a record of heat input for the main boiler, auxiliary boiler, emergency generator, fire water pump and fire water booster pump.

C. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operational log, which shall detail each startup, shutdown, and malfunction of the pulverized coal boiler and associated pollution control systems.

D. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operational log, which shall detail each startup, shutdown, and malfunction of the auxiliary boiler. This operations log shall include a running total of the hours per year the auxiliary boiler is on-line.

E. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operational log for the emergency diesel generator that includes a running total of the hours per year the emergency diesel generator is in use.

F. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operational log for the emergency fire pump that includes a running total of the hours per year the emergency fire pump is in use.

G. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain an operational log for the emergency fire water booster pump that includes a running total of the hours per year the emergency fire water booster pump is in use.

H. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain inspection, maintenance, and repair log(s) for the pulverized coal boiler, auxiliary boiler, emergency diesel generator, fire water pumps and associated pollution control systems.

I. Associated Electric Cooperative, Inc. Norborne Power Plant shall record the analysis of higher heating value, ash, sulfur and moisture content of every shipment of coal that is delivered to the installation, using a sample that is collected in a manner representative of the entire shipment. Compliance with this condition may be demonstrated by recording the analytical results from the fuel supplier.

J. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

a log of the amount of fuel oil burned in the main boiler.

K. Associated Electric Cooperative, Inc. Norborne Power Plant shall record the fuel sulfur results from coal sampling conducted as per special condition 11.A.

L. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain a record of the fuel sulfur content of the fuel oil as per special condition 11.B.

M. Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the daily amount of water circulated in the cooling tower.

N. Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records of the TDS in the circulated cooling water in accordance to special condition 5.D.

O. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain daily records to document the number of trips and type of material hauled to demonstrate compliance with special condition 6.A.

P. Associated Electric Cooperative, Inc. Norborne Power Plant shall keep records for the haul roads, storage piles and vehicular activity areas as per special conditions 6.D.2)b), 6.D.3)b) and d), 7.C.3), and 7.D.3)b) and d).

Q. Associated Electric Cooperative, Inc. Norborne Power Plant keep records for chemical binder use as per special condition 8.F.3)

R. Associated Electric Cooperative, Inc. Norborne Power Plant shall keep a log of the time and date that maintenance activities occur, as well as the times that railcar unloading occurs to show compliance with special condition 8.G. In conjunction with the railcar unloading, a record of the amount of coal unloaded shall be kept in order to show compliance with special condition 8.A.

S. Associated Electric Cooperative, Inc. Norborne Power Plant shall keep a record of the moisture content of the fly ash and bottom ash as per special condition 8.I.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

T. Associated Electric Cooperative, Inc. Norborne Power Plant shall maintain all records required by this permit for not less than five (5) years and shall make them available immediately to any Missouri Department of Natural Resources' personnel upon request.

16. Reporting

A. Associated Electric Cooperative, Inc. Norborne Power Plant shall report to the Air Pollution Control Program's Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten (10) days after the day in which emissions exceed the limits established by this permit.

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall report to the Air Pollution Control Program's Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten (10) days after the day in which operation of equipment at this installation is not in accordance with any operational limitation or condition established by this permit.

17. Restriction of Public Access – Fencing or Physical Barrier to Restrict Public Access to Property

A. Associated Electric Cooperative, Inc. Norborne Power Plant shall preclude public access to property that is considered within the non-ambient air zone with respect to the air quality impact analysis conducted for this permit. Installation and maintenance of a fence or other physical barrier shall be the means to preclude public access. A map showing property boundary (precluded areas) can be found *Ambient Air Quality Impact Analysis (AAQIA) for Associated Electric Cooperative, Inc. Norborne Power Plant, Prevention of Significant Deterioration (PSD) Modeling, Figure 4, AECI – Norborne Plant Property Boundary, dated October 10, 2007*.

B. Associated Electric Cooperative, Inc. Norborne Power Plant shall complete construction of the physical barrier to enclose the area prior to commencing operation of any equipment contained in this permit.

18. Associated Electric Cooperative, Inc. Norborne Power Plant shall notify the Air Pollution Control Program before initial startup of any changes to the location and construction of buildings as specified in *date, title of modeling document. In the event that there are changes, AECI shall submit an update of date, title of modeling document to the Air Pollution Control Program for their review in order to determine if further air quality analysis is necessary.*

19. In the event that there are conflicting requirements or specifications when comparing state and federal regulations and laws, the contents of the amended

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

permit application and the conditions of this permit, the most stringent requirements or specifications shall apply.

20. Associated Electric Cooperative, Inc. Norborne Power Plant shall submit an as-built report within 180 days of initial start-up. The report shall contain at minimum the design specifications for all major pieces of equipment and an updated process flow diagram for the plant.

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT AND OPERATE
SECTION (8) REVIEW
Project Number: 2006-01-066
Installation ID Number: 033-0033
Permit Number:

Associated Electric Cooperative, Inc.
Norborne Power Plant
30239 JJ Hwy.
Norborne, MO 64668

Complete: December 27, 2006
Reviewed: May 4, 2007

Parent Company:
Associated Electric Cooperative, Inc.
P.O. Box 754
Springfield, MO 65801

Carroll County, S8, 17, 20, T52N, R25W

REVIEW SUMMARY

- Associated Electric Cooperative, Inc. Norborne Power Plant (AECI – Norborne) has applied for authority to construct a new supercritical pulverized coal-fired boiler with related material handling and pollution control equipment and a steam turbine generator with a net electrical output of 689 Megawatts(MW) [780 MW gross output].

- 40 CFR Part 60 Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978,* of the New Source Performance Standards (NSPS) applies to the pulverized coal fired boiler.

- 40 CFR Part 60, Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units,* of the NSPS applies to the auxiliary boiler.

- 40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants,* of the NSPS applies to the coal processing and conveying equipment (including the crushers), coal storage systems, and coal transfer and loading systems.

- 40 CFR Part 60, Subpart OOO, *Standards of Performance for Nonmetallic Mineral Processing Plants,* of the NSPS applies to lime handling processes.

- 40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, of the NSPS applies to the emergency diesel generator, the fire water pump and the fire water booster pump.

- None of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or currently promulgated Maximum Achievable Control Technology (MACT) regulations applies to the proposed equipment.

- On May 31, 2006, the Environmental Protection Agency (EPA) published in the Federal Register a final rule entitled *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units*. This rule, otherwise known as the Clean Air Mercury Rule, established emission limitations for vapor phase mercury for new coal-fired utility units and it also created a market-based cap and trade system for mercury emissions. The cap and trade system applies to both existing and new coal-fired utility units. The vapor phase mercury emission limitation established in the Clean Air Act Mercury Rule for new coal-fired utility units burning sub-bituminous coal is dependent upon the amount of precipitation that is typical for the area where the plant is located. In AECI – Norborne's case, the limit is 66 X 10^{-6} lb/gross MWh.

- On March 29, 2005 EPA published a final rule entitled *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electrical Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electrical Utility Steam Generating Units from the Section 112(c) List*. Through this rulemaking EPA has concluded that it is no longer appropriate or necessary to regulate coal- and oil- fired utility units under section 112 of the Clean Air Act and has removed such units from the 112(c) list.

- 10 CSR 10-6.060(9) is the section of the State construction permits rule that applies to major sources of hazardous air pollutants. Before EPA's rulemaking of March 29, 2005, a Section (9) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs) would have been required as part of this permitting process. However, there is an exemption at Subsection (C) of Section (9) that states the following:

  > *The requirements of section (9) of this rule do not apply to-*
  > 1. *Electrical utility steam generating units unless they are listed on the source category list established in accordance with section 112(c) of the Clean Air Act; or*
  > 2. *Research and development activities.*

  Accordingly, a case-by-case MACT analysis is not required for HAPs such as mercury, hydrochloric acid and hydrogen fluoride.

- Note that after the public comment period ended but before the final permit was issued, the United States Court of Appeals for the District of Columbia Circuit issued a decision on February 8, 2008 that vacates EPA's 2005 delisting rule, 70 Fed.Reg. 15,994 (Mar. 29, 2005) whereby EPA delisted coal-fired electric utility steam generating units (EGUs) from the list of sources whose emissions are regulated under Section 112 of the Clean Air Act, 42 U.S.C. section 7412. The Court of Appeals further vacated the Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units (CAMR), 70 Fed. Reg. 28,606 (May 18, 2005). *New Jersey v. Environmental Protection Agency,* _ F.3d __, 2008 WL 341338 (D.C. Cir. 2008). Because that appellate decision is not yet final but calls into question the validity of the CAMR rule referenced in this permit, AECI can either wait the outcome of that litigation or proceed with obtaining a MACT determination pursuant to 10 CSR 10-6.060(9) related to Hazardous Air Pollutants. Should AECI pursue the MACT determination, such determination by the MDNR will be a separate but related permit which fully complies with the applicable public notice and comment procedures of the Missouri Air Conservation Law.

- The Best Available Control Technology (BACT) requirements apply to the pollutants NO_x, SO_2, particulate matter, PM_{10}, CO, VOC, and SAM.

- This review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*. Potential emissions of SO_X, CO, NO_X, total PM_{10}, VOC and sulfuric acid mist (also known as SAM or H_2SO_4) are above Prevention of Significant Deterioration (PSD) significant levels.

- This installation is located in Carroll County, an attainment area for all criteria air pollutants.

- This installation is on the List of Named Installations [10 CSR 10-6.020(3)(B), Table 2, Number 26 – *Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input*]. Therefore, the major source threshold for all criteria pollutants is 100 tons per year.

- Air quality modeling for this project was performed to determine the ambient impact of air pollutants. Based upon the air dispersion modeling reviewed by the Air Pollution Control Program staff, the study submitted by AECI – Norborne is complete and demonstrates that the installation will not contribute to any violation of the National Ambient Air Quality Standards (NAAQS) or available increment.

- Emissions testing for condensable PM, VOC, SAM, mercury, lead, hydrogen fluoride and beryllium will be required as specified in the special conditions of this permit. Continuous Emission Monitoring Systems (CEMS) are required on the new pulverized coal fired boiler to demonstrate compliance with NO_X, SO_2, CO, and both filterable and total PM_{10} emission limits.

- A Part 70 Operating Permit application is required for this installation within 1 year of equipment startup.

- Approval of this permit is recommended with special conditions.

INSTALLATION/PROJECT DESCRIPTION

AECI – Norborne is to be constructed at a Greenfield site approximately three miles west of Norborne on a 1,500-acre plot. The plant includes the boiler, auxiliary equipment, cooling towers, pollution control equipment, rail spur, coal storage area, material handling equipment and utility waste landfill.

Main Boiler

AECI – Norborne is proposing to build a new supercritical pulverized coal fired (PC-fired) boiler with a steam turbine generator with a nominal (= rated) net electrical output of 689 MW (780 MW gross output). The unit will provide base load electricity and is designed to operate continuously. Construction of the plant is scheduled to begin in the early part of 2008 with commercial operation starting in 2012.

Low sulfur sub-bituminous Powder River Basin (PRB) coal is the intended fuel. The fuel is pulverized to the consistency of talcum powder and pneumatically injected through the burners into the furnace. PC-boilers are of a watertube design, meaning that the heat from the combustion gases is used to heat water inside of tubes and convert it to steam. The unit will be a dry bottom unit; coals with high fusion temperatures are burned, resulting in dry ash.

NO_X emissions will be controlled by LNB, over-fire air (OFA) and SCR. Baghouses will be used for filterable PM_{10}, acid gas and other inorganic HAP control; while DFGD using lime will limit SO_2 emissions. A combination of baghouses and DFGD will control total PM_{10} emissions. CO and VOC emissions will be controlled using good combustion practices. The following table provides a summary of the design parameters of the proposed boiler/generator.

Table 2: Design Parameters for Main Boiler

Parameter	Design Criteria
Gross Plant Output	781,773 kW
Net Plant Output (nominal)	688,909 kW
Maximum Heat Input to Boiler	6,872 MMBTU/hr
Annual Capacity Factor	100%
Primary Fuel	Low sulfur western sub-bituminous PRB coal
Higher Heating Value*	8,100 BTU/lb
Primary Fuel Feed Rate	429.5 tons/hr
Ash Content	7.5%
Moisture Content	32.2%
Maximum Sulfur Content	0.50%
Start-Up/ Back-Up Fuel	Low sulfur #2 fuel oil (<0.05% by weight)
Annual Fuel Oil Usage	500 Mgal/yr

*AECI submitted the application using a HHV value of 8,000 BTU/lb. The HHV has been adjusted according to coal analyses provided by AECI. The primary fuel feed rate is left unchanged to provide the worst case scenario for HAP emissions calculations.

Auxiliary Equipment

An auxiliary boiler will be constructed for use during start-up of the main boiler and during cold weather to supply heating steam for the boiler and turbine buildings. The boiler will have a maximum heat input rate of 374.9 MMBTU/hr (2.678 Mgal/hr) and be fueled with #2 fuel oil only (with heating value of 140,000 Btu/gallon). Hours of operation for the boiler will not exceed 2,190 hours per year and the unit will be equipped with LNB and flue gas recirculation (FGR).

A 2,367 horsepower emergency diesel generator equipped with retard timing will be installed. Heat input to this unit will be 18.25 MMBTU/hr (0.1294 Mgal/hr). Hours of operation for the generator will not exceed 500 hours per year.

A 432 horsepower diesel fire water pump is proposed and will operate a maximum of 500 hours per year. The required heat input to the fire water pump is 3.33 MMBTU/hr (23.6 gal/hr).

Additionally, a 140 horsepower diesel fire water booster pump is needed for the fire water system to function effectively. The required heat input to the fire water pump booster pump is 1.08 MMBTU/hr (7.71 gal/hr).

Cooling Towers

Evaporative cooling towers will be used to cool water from the plant. The towers are used to cool water by exposing droplets to ambient air. The cooling towers are designed with a circulation rate of 375,000 gal/min and five cycles. When water is evaporated, the solids are left behind. The cycles of concentration are the number of times the solids are concentrated by evaporation. For example, five cycles of concentration of city water would be water having five times more solids than city water.

Coal Handling

Coal will arrive at the site by rail and will be unloaded using a rail car rotary car dumper into two underground hoppers located inside the Railcar Coal Unloading Building at a rate of 4,000 tph. The hoppers will be equipped with baghouses to control emissions from unloading (EP-2A and EP-2B). It is expected that 85% of the emissions will be captured during the unloading process. The captured emissions will be controlled at a removal rate of 99%. Therefore, the overall efficiency of the coal dumper is 84.2%.

A belt feeder BF-1A/B will then transfer the coal from the hoppers to a conveyor (CC-1) then on to conveyor (C-1). Coal is then transferred to either conveyor C-2 or C-3 (TP-1). Finally, the coal is loaded in to either the active coal pile (TP-8A) or the reserve (emergency) coal pile (TP-8B). Coal will be discharged on the piles using telescoping chutes. Residual binder on the coal and water sprays will aid in reducing emissions from these transfers.

There will be adjacent active, inactive and reserve (emergency) storage piles at the site. Coal will be bulldozed to and from the inactive pile from the active pile, rather than by conveyor transfer. The active coal storage pile will maintain approximately three days worth of capacity, or 25,000 tons, occupying approximately 1.44 acres of land. The reserve (emergency) pile will be approximately the same size. The inactive coal storage pile will maintain nearly sixty days of capacity, or 450,000 tons. This pile will have a footprint of approximately 10.35 acres. Moisture content of the coal stored in piles is expected to be 4.5%.

An underground reclaim system will operate at a maximum hourly design rate of 2,400 tons per hour (EP-29) to transport coal from the stockpiles to the crusher house. A series of parallel conveyors will route the coal to two coal crushers, rated at 1,200 tons per hour each. Emissions from these processes will be vented to two baghouses (EP-28A and EP-28B).

Conveyor C-6 finally transports coal from the crusher house to the coal tripper house where another series of conveyors will guide the pulverized coal to the coal bunkers feeding the main boiler. All tripper house emissions will be vented to baghouse (EP-26).

Lime Handling

Lime will arrive at the plant by truck whereupon it will be transferred to the lime storage silo (EP39) at a rate of 25 tons per hour. A baghouse will control emissions from the truck unloading. The lime will be transferred from the lime silo to the DFGD system where it will be used to control SO_2 emissions.

Fly Ash Handling

Fly ash from the boiler will be collected in baghouses and stored in silos (EP-30 and EP-33). Exhausters will provide additional control (EP-35 and EP-32). From the silos, the ash can be recirculated in the DFGD, to reduce SO_2 emissions. The fly ash/lime mixture exiting the DFGD will again be collected in the baghouse and either transferred to silos for additional recirculation or loaded onto truck and transferred to the landfill. The recirculated fly ash system will have 100% capture efficiency and 99% control efficiency. All fly ash that is not used in the DFGD is taken from the original set of silos, mixed with water, and then transferred to open-bed haul trucks (TP-31) to be disposed of at the utility waste landfill.

Bottom Ash Handling

Pyrites from the coal mill will be transported by sluice line to the bottom of the boiler furnace. Bottom ash from the boiler furnace and the pyrites will then be removed using a submerged scraper conveyor that moves the ash onto the floor of a concrete bunker where it is drained and loaded on trucks (TP-36). A dry conveyor will be used to transport economizer ash from the economizer directly to the submerged scrape conveyor. The trucks will transport the ash from the concrete bunker to the utility waste landfill.

Utility Waste Landfill

A 142-acre utility waste landfill will be constructed for disposal of fly ash, bottom ash and other utility wastes. AECI – Norborne will have both paved and unpaved portions of haul road to the utility waste landfill onsite. The roads will be watered and/or have surfactant applied to reduce fugitive emissions.

Activated Carbon or Sorbent Use

Activated carbon (or an equivalent sorbent) will be brought to the site via trucks and unloaded to the activated carbon storage silo. Emissions from the silo will be controlled using a baghouse. The activated carbon will be transported from the silo and injected into the flue gas stream as an aerosol. The activated carbon injection system will inject the activated carbon into the flue gas to control mercury emissions. The injection rate will vary according to the actual need for control as determined by the stack mercury continuous emissions monitoring system. A baghouse will capture the activated carbon mixture from the gas stream and dispose of the waste in the utility waste landfill.

Haul Roads
There will be three designated haul roads at the installation. HR-1 and HR-2 are paved roads that will be used to transport lime and activated carbon. Landfill wastes will be transported on HR-2, then on HR-3. HR-3 is an unpaved haul road that lies within the landfill.

Tanks
There will be five storage tanks on the premises. A 500,000-gallon tank (T-01) will hold number 2 fuel oil to be used for startup for the main boiler and for operation of the auxiliary boiler. A second tank (T-02) will hold up to 2,000 gallons of diesel fuel for the emergency generator. A smaller, 700 gallon diesel tank (T-03) will store fuel for the fire water pump. The smallest tank (T-06), having a capacity of only 230 gallons, will store number 2 fuel oil for the fire water booster pump. Two remaining tanks (T-04 and T-05) will hold the lube oil and hydraulic fluid for the steam turbine. Both of these tanks will be part of closed loop systems.

EMISSIONS/CONTROLS EVALUATION

Main Boiler
Emissions from coal combustion are dependent on several factors: rank and composition of the fuel, type and size of boiler, firing conditions, load, control technologies used, and the level of equipment maintenance. The main boiler will emit PM_{10}, SO_2, NO_X, CO, VOC, H_2SO_4, lead, mercury and a variety of HAPs. Of these pollutants, PM_{10}, SO_2, NO_x, CO, VOC and H_2SO_4 are subject to BACT analysis. Potential emissions of these pollutants are based on the BACT limits derived from those analyses.

PM_{10} emissions consist of filterable and condensable fractions: the filterable fraction is caught in the front half of the sampling train, while the condensable fraction is emitted in the vapor state and later condenses to form mainly inorganic aerosol particles. For PC-boilers, filterable PM_{10} emissions result mainly from the inorganic ash residues found in the coal, since combustion is nearly complete. AECI – Norborne believes that 90% of its residues will be fly ash; the remaining 10% will exit the boiler as bottom ash. Fly ash will be controlled by baghouses at the installation, while a submerged scraper conveyor collects bottom ash. The collected ash will be transported by truck to a utility waste landfill. Since filterable PM_{10} emissions are dependent on the amount of ash, as load decreases, so do filterable PM_{10} emissions.

Sulfur oxide emissions from the main boiler will mostly take the form of SO_2, though there will be some sulfur trioxide and gaseous sulfates emitted. The organic and pyritic sulfur in the coals oxidizes during the combustion process. Sub-bituminous coals tend to create a more alkaline ash that is conducive to the formation of sulfate salts that are retained in the boiler and in the fly ash. Nonetheless, slightly less than 95% of the sulfur in the coal will be emitted as SO_x. AECI – Norborne will be controlling its SO_x emissions through the use of DFGD. The DFGD will also control emissions of acid gases (H_2SO_4).

NO_X emissions result from the thermal fixation of atmospheric nitrogen in the combustion flame, and to a much lesser extent, from the oxidation of nitrogen bound in the coal. Thermal NO_X formation is dependent on temperature, nitrogen and oxygen concentrations in the flame and the gas residence time. To control NO_X emissions, AECI – Norborne intends to use combustion controls, LNB, over-fired air and SCR.

Carbon monoxide and volatile organic compound emissions depend on fuel oxidation efficiency; therefore, emissions can be minimized by careful control of the combustion process and keeping the unit well maintained.

Emissions of trace metals are dependent on several factors: the physical and chemical properties of the particular metal, the concentration of the metal in the coal, the combustion conditions and the type of particulate control device used, and its efficiency as a function of particle size. Lead emissions tend to be enriched in both the fly ash stream relative to the bottom ash stream, or show enrichment with decreasing particle size. Control of lead emissions then, is dependent on collection of fine particulate. All HAP emissions, but mercury, were calculated using emission factors from AP-42, Section 1.1, *Bituminous and Subbituminous Coal Combustion* (9/98).

Mercury emissions tend to be emitted in the gas phase. Because of its volatility, particulate controls have only a limited impact on these emissions. AECI – Norborne will capture a fraction of this pollutant in the same baghouses used for PM_{10} control. Activated carbon injection will be utilized to insure added removal of mercury. Potential mercury emissions are based on a controlled emission rate of 0.0516 lb/hr needed to comply with the NSPS, Subpart Da standard of 66×10^{-6} lb/MWh (Carroll County receives greater than 25 inches of rain annually).

Auxiliary Equipment

Other combustion sources at the installation include the auxiliary boiler, emergency generators and emergency fire pumps. These units will also emit NO_X, PM_{10}, SO_2, CO and VOC.

Emission estimates are based on the BACT analyses that were conducted on each auxiliary unit for each of these pollutants. The boiler will be equipped with LNB and flue gas recirculation (FGR) to minimize NO_X emissions. Combustion controls will reduce emissions of NO_X, CO, VOC and PM_{10} from the emergency diesel generator, fire water pump and fire water booster pump. Low-sulfur fuel oil will reduce SO_2 and H_2SO_4 emissions.

Cooling Towers

Evaporative cooling towers will be used to cool water from the plant. Filterable PM_{10} emissions occur from the towers when impurities in the water droplets entrained in the air stream are emitted as “drift”. Drift eliminators will be installed to reduce the amount of drift to 0.0005% of the circulating water leaving the cooling towers. The amount of filterable PM_{10} emissions is also directly related to the level of impurities (or dissolved solids) in the drift droplets. The dissolved solids in the make-up water will not exceed 1,000 ppm. The cooling towers are designed to operate with five cycles; therefore, the maximum TDS after five cycles should never exceed 5,000 ppm. Potential emissions from the cooling towers were based on a mass balance using the assumptions on TDS and the level of drift.

Material Handling

Material handling equipment for coal, fly ash, lime, activated carbon and the utility waste landfill are also expected to emit filterable PM_{10}. The following sources were used to determine potential emissions from the various materials handling processes:

- AP-42, Table 11.19.2-2 (8/04) – conveyor transfer point for crushed stone processing operations – used to calculate emissions from coal railcar unloading and some coal conveyor transfer points
- AP-42, Section 13.2.4 (1/95) – aggregate handling and storage piles – drop point equation used for outdoor conveyor transfer points
- MDNR Form 2.8 – used to determine wind erosion and vehicular activity from storage piles
- AP-42, Table 11.9-1 – bulldozing at western surface coal mines – used to calculate emissions from bulldozing of coal from active piles to inactive pile
- The Factor Information Retrieval (FIRE) Data System, Version 6.23, SCC 3-05-010-10 – used to compute emissions from coal crushing
- AP-42, Table 11.12-2 – cement unloading to silo – used to calculate emissions from ash storage silos
- AP-42, Table 11.17-4 – product transfer and conveying – used to compute emissions from lime and activated carbon unloading

Controls for material handling sources have been discussed in the previous section.

Haul Roads

The haul road in the landfill (HR-3) will be unpaved, since it will constantly be changing location, according to what cells are being used at the landfill at any given time. Documented watering or chemical surfactant will be used on this road to provide 90% control of emissions. After the waste arrives at the landfill, there is activity that takes place at the landfill, such as bulldozing activities that will result in emissions. The paved roads at the plant (HR-1 and HR-2) that are used for activated carbon, lime and for waste headed toward the landfill will be washed periodically to provide at least 95% control of filterable PM_{10} emissions. Emission factors for the haul roads and landfill activities were taken from the Environmental Protection Agency (EPA) document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition, Section 13.2.2, *Unpaved Roads* (12/2003).

Tanks

Emissions from the fuel storage tanks (T-01, -02, -03 and -06) will consist of working and breathing losses. Working losses result from evaporation during filling and emptying operations, while breathing losses are a result of evaporation during storage. Potential emissions were calculated using EPA's TANKS 4.09A program. The tanks that store hydraulic fluid (T-05) and lube oil (T-04) are part of closed loop systems. No emissions are expected from these tanks.

Potential emissions of the application represent the potential of the new equipment, assuming continuous operation (8760 hours per year) for all but the auxiliary equipment. Start-up and shutdown emissions, although considered in the modeling analysis, are not included in the potential annual emissions. Potential emissions from the auxiliary boiler, emergency generator and the fire water pumps are all based on the limited hours of operation defined in the special conditions. Since this is a new installation, there are no existing potential or actual emissions. The following table provides an emissions summary for this project.

Table 3: Emissions Summary (tons per year)

Pollutant	Regulatory *De Minimis* Levels	Existing Potential Emissions	Existing Actual Emissions	Potential Emissions of the Application	New Installation Conditioned Potential
PM_{10}	15.0	N/A	N/A	541.79	N/A
SOx	40.0	N/A	N/A	2429.74	N/A
NOx	40.0	N/A	N/A	1504.97	N/A
VOC	40.0	N/A	N/A	111.26	N/A
CO	100.0	N/A	N/A	4552.05	N/A
H_2SO_4	7.0	N/A	N/A	115.47	N/A
HAPs	10.0/25.0	N/A	N/A	155.98	N/A
Mercury	0.1	N/A	N/A	0.23	N/A
Lead	0.6	N/A	N/A	0.15	N/A
HCl	10.0	N/A	N/A	102.84	N/A
HF	10.0	N/A	N/A	31.82	N/A

N/A = Not Applicable

PERMIT RULE APPLICABILITY

This review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*. Potential emissions of SO_X, CO, NO_X, PM_{10}, and VOC are above PSD significant levels. Section (9) of 10 CSR 10-6.060 does not apply for the reasons stated in the review summary.

APPLICABLE REQUIREMENTS

Associated Electric Cooperative, Inc. Norborne Power Plant shall comply with the following applicable requirements. The Missouri Air Conservation Laws and Regulations should be consulted for specific record keeping, monitoring, and reporting requirements. Compliance with these emission standards, based on information submitted in the application, has been verified at the time this application was approved. For a complete list of applicable requirements for your installation, please consult your operating permit.

GENERAL REQUIREMENTS

- *Submission of Emission Data, Emission Fees and Process Information,* 10 CSR 10-6.110
  The emission fee is the amount established by the Missouri Air Conservation Commission annually under Missouri Air Law 643.079(1). Submission of an Emissions Inventory Questionnaire (EIQ) is required April 1 for the previous year's emissions.
- *Operating Permits*, 10 CSR 10-6.065
- *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin*, 10 CSR 10-6.170
- *Restriction of Emission of Visible Air Contaminants*, 10 CSR 10-6.220
- *Restriction of Emission of Odors*, 10 CSR 10-3.090
- *Open Burning Restrictions*, 10 CSR 10-3.030
- *Start-Up, Shutdown and Malfunction Conditions*, 10 CSR 10-6.050

SPECIFIC REQUIREMENTS

- *Restriction of Emission of Particulate Matter From Industrial Processes*, 10 CSR 10-6.400
- *New Source Performance Regulations*, 10 CSR 10-6.070
  - *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, 40 CFR Part 60, Subpart Da
  - *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units,* 40 CFR Part 60, Subpart Db
  - *Standards of Performance for Coal Preparation Plants,* 40 CFR Part 60 Subpart Y
  - *Standards of Performance for Nonmetallic Mineral Processing Plants,* 40 CFR Part 60, Subpart OOO
  - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, Subpart IIII
- *Restriction of Emission of Sulfur Compounds*, 10 CSR 10-6.260
- *Maximum Allowable Emissions of Particulate Matter From Fuel Burning Equipment Used for Indirect Heating,* 10 CSR 10-3.060
- *Emission Limitations and Emissions Trading of Oxides of Nitrogen,* 10 CSR 10-6.350
- *Emissions Banking and Trading*, 10 CSR 10-6.410
- *Acid Rain Source Permits Required*, 10 CSR 10-6.270

BACT ANALYSIS

This BACT analysis has been supplemented with further information found in the attached Response to Comments.

Introduction
Any source subject to Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, Section (8) must conduct a BACT analysis on any pollutant emitted in greater than de minimis levels. The BACT requirement is detailed in Section 165(a)(4) of the Clean Air Act, at 40 CFR 52.21 and 10 CSR 10-0.60(8)(B).

A BACT analysis is done on a case by case basis and is performed in general by using a “top-down” method. The following steps detail the top-down approach:

1. Identify all potential control technologies – must be a comprehensive list, it may include technology employed outside the United States and must include the Lowest Achievable Emission Rate (LAER) determinations.
2. Eliminate technically infeasible options – must be well documented and must preclude the successful use of the control option.
3. Rank remaining control technologies – based on control effectiveness, expected emission rate, expected emission reduction, energy impacts, environmental impacts, and economic impacts.
4. Evaluate the most effective controls – based on a case-by-case consideration of energy, environmental, and economic impacts.
5. Select BACT.

BACT FOR PULVERIZED COAL FIRED BOILER - NO_X
The formation of NO_x is determined by the interaction of chemical and physical processes occurring primarily within the flame zone of the boiler. There are two principal forms of NO_x designated as “thermal” NO_x and “fuel” NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. Fuel NO_x is formed by the oxidation of nitrogen in the fuel. NO_x formation can be controlled by adjusting the combustion process and/or installing post-combustion controls as well as monitoring coal properties for nitrogen.

NO_x control technologies can be divided into two general categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NO_x that is generated in the boiler. Post-combustion controls remove NO_x from the boiler exhaust gas.

Potentially available control options were identified based on a comprehensive review of available information. The following NO_x control technologies with potential application to the proposed AECI boiler are listed below.

NO_x Control Technologies for Pulverized Coal Fired Boilers

- Combustion Controls
  - Low Excess Air (LEA)
  - Low NO_x Burners (LNB)
  - Overfire Air (OFA)
  - Flue Gas Recirculation (FGR)
  - Reburning
- Post-Combustion Controls
  - Selective Noncatalytic Reduction (SNCR)
  - Selective Catalytic Reduction (SCR)
- Innovative Control Technologies
  - Rotating Overfire Air (ROFA)
  - ROFA + SNCR (Rotamix)
  - Pahlman Process
  - Wet NOx Scrubbing

Discussion of NO_x Control Technologies for Pulverized Coal Fired Boilers

- Low Excess Air (LEA)

The LEA approach incorporates combustion controls in order to reduce the amount of excess air supplied to the firing chamber. With LEA firing, adjustments of air registers, fuel injector positions, overfire air dampers and operational controls reduce the amount of excess air in the combustion chamber. By limiting the excess air, the combustion temperature is lowered which in turn reduces the amount of NO_x formed during the combustion process. LEA has been used on large coal-fired units combusting low-sulfur subbituminous coals.

- Low NO_x Burners (LNB)

LNBs limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. LNBs have been used extensively on large coal-fired units combusting low-sulfur subbituminous coals.

- Overfire Air (OFA)

In the OFA process, the injection of air into the firing chamber is staged into two zones. The staging of the combustion air results in a cooler flame, and it also results in less oxygen reacting with fuel molecules. Both of these mechanisms in turn reduce NO_x formation. OFA has been used on extensively large coal-fired units combusting low-sulfur subbituminous coals.

- Flue gas recirculation (FGR)

FGR controls NO_x by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_x emissions by two mechanisms: (1) the recycled gas is made up of combustion products which are inert during combustion, thereby lowering combustion temperatures, and (2) by lowering the oxygen content in the primary flame zone. Although FGR may be considered as a potential control option, it is not typically installed on coal fired units due to the high hot particulate-laden flue gas with relatively high O_2 concentrations. FGR on a coal-fired boiler is estimated to achieve a NO_x reduction efficiency of less than 20%, due to a relatively low contribution of thermal NO_x to total NO_x formation. It is considered less effective than the alternative post-combustion NO_x control options (E.g., SCR and SNCR) and therefore will not be examined further.

- Reburning

In reburning, up to 25% of the total fuel heat input is provided by injecting a secondary (or reburning) fuel above the main combustion zone to produce a slightly fuel-rich zone with a stoichiometry of about 90% theoretical air. Combustion of reburning fuel at fuel-rich conditions result in hydrocarbon fragments, which react with a portion of incoming NO_x to form hydrogen cyanide, isocyanic acid, and other nitrogen-containing species. These species are ultimately reduced to nitrogen. Finally, completion air is added above the reburn zone to complete burnout of reburning fuel. It is estimated that a reburn technology could provide a 50% NO_x reduction in emissions.

- Selective Non-Catalytic Reduction (SNCR)

SNCR involves the direct injection of ammonia or urea at high flue gas temperatures (approximately 1600 ^oF – 1900 ^oF). The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water. Although an SNCR system has been used as a retrofit, SNCR systems have not been applied to large new pulverized coat (PC) units. PC boilers present several design problems that make it difficult to ensure that the reagent will be injected at the optimum flue gas temperature, and that there will be adequate mixing and residence time. Because of the difficulties associated with applying SNCR to a large PC boiler, it is estimated that an SNCR system could provide a 30% NO_x reduction in emissions.

- Selective Catalytic Reduction

The SCR system involves injecting ammonia into the boiler flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NO_x level, the catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable. The SCR system has been demonstrated on several large PC boilers on a continuous basis and many boilers have been retrofitted with SCRs to control NO_x emissions during ozone season. The SCR system is estimated to achieve an additional 50% to 90% reduction.

- Rotating opposed fired air (ROFA) and Rotamix®

Rotating opposed fired air (ROFA) is a boosted overfire air system that includes a patented rotation process. Like typical OFA systems, ROFA stages the primary combustion zone to burn overall rich, with excess air added higher in the furnace to burnout products of incomplete combustion. The ROFA nozzles are designed to increase turbulence within the furnace, enabling the furnace volume to be used more effectively for the combustion process, and reduce the maximum temperatures of the combustion zone. A ROFA system was installed on an existing 80-MW (gross) bituminous-fired utility boiler in the summer of 2002. Test results showed that the

ROFA system reduced NO_x emissions from a baseline level between 0.58 to 0.62 lb/MMBTU to approximately 0.22 lb/MMBTU at full load. At low load (40-MW), the ROFA system reduced NO_x emissions from 0.59 lb/MMBTU to 0.295 lb/mmBTU.

Mobotec's Rotamix system combines the ROFA system with urea injection into the flue gas (SNCR) to reduce NO_x emissions. A Rotamix control system was installed on the same 80-MW unit in the spring of 2004. Test results showed that the Rotamix system achieved controlled NO_x emission limit of approximately 0.10 lb/MMBTU at full load and 0.18 lb/MMBTU at half-load. The combination of ROFA and urea injection appears to be a technically feasible NO_x control strategy. Based on available technical documents and testing conducted at an existing coal-fired boiler, the combination of combustion controls with SNCR (Rotomix-type design) may achieve an actual NO_x emission rate of approximately 0.10 lb/MMBTU.

- Pahlman™ Process

The Pahlman Process is a patented dry-mode multi-pollutant control system. The process uses a sorbent composed of oxides of manganese to remove NO_x and SO_2 from the flue gas. In general, the liquid metal oxide Pahlmanite sorbent is injected as the flue gas enters a spray dryer. The sorbent dries as it passes through the spray dryer and is collected downstream at the fabric filter baghouse. NO_x and SO_2 will react with the sorbent to form manganese sulfates and nitrates as the flue gas passes through the filter cake. The filter cake is pulsed off-line into a wet regeneration process. The regenerated sorbent is stored in liquid form to be employed again via the spray dryer. The captured nitrogen and sulfur can be purified and may be converted into granular fertilizer by-products.

To date, bench- and pilot-scale testing have been conducted to evaluate the technology on utility-sized boilers. The New & Emerging Environmental Technologies (NEET) Database identifies the development status of the Pahlman Process as full-scale development and testing. There is limited information available to evaluate its long-term effectiveness on a large subbituminous-fired boiler and it is likely that AECI would be required to conduct extensive design engineering and testing to evaluate the long-term effectiveness of the system. Therefore, at this time, the Pahlman process is not considered commercially available for the proposed plant and will not be further evaluated in this BACT analysis.

- Wet scrubbing systems

Wet scrubbing systems have been used to remove NO_x emissions from fluid catalytic cracking units at petroleum refineries. They have also been installed at chemical processing plants and smaller coal-fired boilers. The NEET Database classifies wet scrubbing systems as commercially established for petroleum refining and oil/natural gas production. However, the technology has not been demonstrated on large coal-fired boilers, and it is likely that AECI would incur substantial engineering and testing to evaluate the scale-up potential and long-term effectiveness of the system. Therefore, at this time wet NO_x scrubbing systems are not considered commercially available for the proposed plant, and will not be further evaluated in this BACT analysis.

Determination of BACT for NO_x for the Main Boiler

The combustion controls that AECI has proposed as achieving the lowest NO_x levels out of the boiler are low NO_x Burners (LNB) and Overfire Air (OFA). Designing the boiler using LNB in conjunction with OFA is a technologically feasible option and has been used extensively in industry. In addition, the boiler proposed for this project will be designed with the LEA approach.

The technically feasible post-combustion control technologies for NO_x in descending order of control efficiency are summarized in the following table.

Table 4 – Technically Feasible NO_x Control Technologies

Control Technology	Emissions (lb/MMBTU)	% Reduction
SCR	0.05 – 0.09	50 –90%
ROTA/SNCR (Rotamix)	0.10	N/A
SNCR	0.24	30%
Combustion Controls: LNBs and OFA (Baseline)	0.35	

AECI has proposed Selective Catalytic Reduction (SCR), which has the highest level for post-combustion controls. Through review of available technical publications and information as well as recently permitted and proposed limits contained in the RBLC and EPA's Modified Coal-Fired Utility Summary Spreadsheet, SCR with LNBs and OFA has been identified as the most commonly applied and effective technology for the control of NO_x emissions from the boiler. Since AECI has proposed the highest level of control for NO_X, no further evaluation of other control technologies has been conducted.

With regards to continuously operated Powder River Basin (PRB) coal-fired pulverized coal (PC) units, SCR is a relatively new control technology, and there are limited operating data available to evaluate long-term effectiveness of SCRs. Kansas City Power & Lights' (KCPL's) Hawthorne Unit 5 ("Hawthorne") is the only new (not retrofitted) PRB coal-fired boiler currently operating in the U.S. which uses SCR technology. The Hawthorne unit had a permitted limit at 0.12 lb/MMBTU on a 30-day rolling average for the first 36 months following initial startup and a permitted limit of 0.08 lb/mmBTU on a 30-day basis after the 36-month evaluation period. Hawthorne began operation around May 2001. AECI evaluated Hawthorne's performance for a period between July 1, 2004 through March 31, 2005 using the Clean Air Market database and determined that Hawthorn Unit 5 has achieved 0.079 lb/MMBTU on a 30-day rolling average with 95% confidence (95% confidence equates to 2 standard deviations).

In addition to the Hawthorne unit, W.A. Parish Generating Station in Houston, Texas also operates year-round subbituminous-fired PC units, Units 5 and 6. These units have been retrofitted with SCRs and LNBs with OFA. The SCR systems for Units 5 and 6 went into service in April 2003 and January 2003, respectively. Based on data evaluated by AECI for the period between June 1, 2003 and June 30, 2005, Parish Units 5 and 6 have consistently achieved a 30-day rolling average of 0.05 and 0.057 lb/MMBTU (with 95% confidence), respectively. Additional review by the Air Pollution Control Program using USEPA's Clean Air Market database showed annual performance ranging from 0.031 to 0.050 lb/MMBTU (with no added standard deviations) from startup of the SCRs through October of 2006. It is believed that there have been no catalyst replacements in the SCRs of these units and that they have been operated continuously over the duration of the evaluation period given above. However, the NO_x levels at W.A Parish Units 5 and 6 have been slowly trending upwards since the end of 2004 and Unit 5 has reached 0.05 lb/MMBTU levels on a 12-month rolling average basis as of October of 2006.

Additional review of over 35 pulverized coal (PC) units contained in RBLC and EPA's Modified Coal-Fired Utility Summary Spreadsheet was conducted. A summary of this list is given in Table 5.

The table shows that recently proposed and permitted units list BACT for most units as between 0.07 and 0.08 lb of NO_x per MMBTU on a 30-day basis. Some exceptions to this are the permitted units at WPSC Weston Plant Unit 4 (which has a 0.06 lb/MMBTU 30-day rolling average) and City Public Service of San Antonio (which has a 0.069 lb/MMBTU 30-day rolling average). There are at least three other facilities that have permitted a 24-hour rolling average NO_x limit (0.067, 0.06, and 0.07 lb/MMBTU). Also, at least five units have also included an annual limit in addition to a 30-day limit. The lowest NO_x annual limit permitted is 0.05 lb/MMBTU.

Table 5: Recent Pulverized Coal NO_x Determinations

Permit Date	Facility Name	State	Output/ Design (MW)	NO_x Limit (lb/MMBTU)	Controls
Proposed	Longview Power, LLC	WV	600 (net)	0.08	SCR w/ LNB
01-14-05	Longleaf Energy Associates, LLC	GA	2 @ 600 MW each	0.07 (30-day)	SCR w/ LNB & OFA
4-14-06 (revised)	Thoroughbred Generating Company, LLC, Peabody Energy	KY	2 @ 750 MW each	0.07 (30-day)	SCR w/ LNB
Proposed	Duke Power	NC	2 @ 800 each	0.08 (30-day)	SCR w/ LNB
4-25-05	Prairie State Generating Station	IL	2 @ 750 each	0.10	SCR
1-14-04	Elm Road Generating Station (Wisconsin Energy)	WI	2 @ 615 each	0.07 (30-day) 0.07 (annual - including SU/SD)	SCR w/ LNB
10-19-04 (Appeal 2-10-06)	Wisconsin Public Service Corporation (Weston Unit 4)	WI	500	0.06 (30 day) 0.06 (annual including SU/SD)	SCR w/ LNB, GCP
8-22-05	Big Cajun II Generation Station, NRG Energy Inc.	LA	675	0.071	SCR w/ LNB
2-09-07	Hugo Generating Station, Western Farmers Electric Cooperative	OK	750	0.07 (30-day) 0.05 (annual)	SCR w/ LNB & OFA
12-28-05	City Public Service of San Antonio, Spruce 2	TX	750	0.2 (1-hour) 0.069 (30-day) 0.05 (annual)	SCR w/ LNB
7-18-06	Sandy Creek Energy Station, LS Power	TX	800	0.07 (30-day) 0.05 (annual)	SCR w/ LNB
7-16-03	MidAmerican, Council Bluffs Unit 4	IA	790	0.07 (30-day)	SCR
Draft 11-2007	Sunflower Electric Power Cooperative, Holcomb Power Plant	KS	3 @ 660 each	0.07 (30-day) 1^{st} 18 months, 0.10 (30-day)	SCR w/ LNB & OFA
12-15-04	Southwest Power Station, City Utilities of Springfield	MO	275	0.08 (30-day)	SCR
8-17-99	Hawthorn Power Station, Kansas City Power & Light	MO	570	0.08 (30-day) 1^{st} 36 months, 0.12 (30-day)	SCR
3-30-04	Hastings, Municipal Energy Agency of Nebraska	NE	220	0.07 (30-day)	SCR w/ LNB
3-09-05	Omaha Public Power District	NE	660	0.07 (30-day) 1^{st} 18 months, 0.10 (30-day)	SCR w/ LNB
07-05-05	Comanche Unit 3, Xcel Energy	CO	750	0.08 (30-day)	SCR
07-21-03	Bull Mountain Development Co., Roundup Power	MT	2 @ 390 each	0.07 (24-hr) 0.1 (1-hr)	SCR
10-15-04	Intermountain Power	UT	950	0.07 (30-day)	SCR

	Service Corp.				
9-26-02	WYGEN 2, Black Hills Power and Light	WY	500	0.07 (30-day)	SCR
Proposed	Desert Rock Energy Facility, Sithe Global	NM	2 @ 750 each	0.06 (24-hr)	SCR w/ LNB
Proposed	Cottonwood Energy Center, BHP Billiton	NM	550	0.06	SCR w/ LNB
5-05-05	Newmont Mining, TS Power Plant	NV	200	0.067 (24-hr)	SCR w/ LNB

Based on the above research and analysis along with further evaluation by the Air Pollution Control Program during the Public Comment phase, the Air Pollution Control Program contends that the top level of control for operation of a PRB coal-fired boiler with LNB/OFA and SCR controls is 0.05 lb/MMBTU on an annual basis. There are no other boilers either permitted or proposed with a lower limit than 0.05 lb/MMBTU on an annual basis. In addition to the annual limit, a 30-day rolling average is also included. The 30-day rolling average was 0.07 lb/MMBtu in the draft permit, but has been lowered to 0.065lb/MMBtu. The addition of a 30-day limit gives the facility flexibility in day to day operation and allows for small upset conditions as well as a small upswing toward the end of catalyst life where they may have some room to plan and allow for the least environmental unfavorable impact due to end of catalyst conditions. It also ensures that emission rates on a shorter time basis remain at a low, consistent level.

As stated above, there are several units with 24-hour NO_x limits. However, since the Air Pollution Control Program is proposing both a 0.065 lb/MMBTU 30-day and an 0.05 lb/MMBTU 12-month limits, the number of exceedances of a 0.65 lb/MMBTU limit on a 24-hour basis is significantly limited by the annual limits and therefore a limit on a 24-hour basis is not included.

The 30-day and 12-month rolling averages are exclusive of startup and shutdown. In order to address the NO_x emissions emitted during these times of operation, AECI has proposed a 1,535 ton cap of NO_x per year. This is based on an emission rate of 0.051 lb/MMBTU and a heat input rate of 6,872 mmBtu per hour.

Lastly, AECI expects that the LNB/OFA controls will reduce the NO_x concentration in the flue gas to 250 ppmvd @ 3% O_2 which is equivalent to 0.35 lb/MMBTU (on a 30-day rolling average basis) under all normal operating conditions on an on-going long-term basis, including low-load operations. Under optimal operating conditions, the LNB/OFA is expected to be operated at 140 ppmvd @ 3% O_2 which is equivalent to 0.2 lb/MMBTU. There are technical papers and data available that suggest that the baseline (inlet to the SCR) of 0.35 lb/MMBTU is relatively high. However, the percent removal of NO_x is dependent on many variables such as the inlet concentration to the SCR. In this case, the greater the inlet NO_x concentration, the higher the percent removal of NO_x that can be achieved. Therefore, rather than set the NO_x limit based on an inlet concentration and percent removal which can vary widely depending on the boiler type, the age of the catalyst, the amount of acceptable ammonia slip, etc., the Air Pollution Control Program is proposing an annual limit of 0.05 lb/MMBTU, which is equal to the most stringent rates being proposed by other facilities and that has been demonstrated on a long-term continuous basis.

AECI conducted an economic evaluation of NO_x emission limits ranging from 0.0535 to 0.09 lb/MMBTU (on a 30-day rolling average). However, as per the draft of NSR Workshop manual, in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Since AECI has not provided any data which differentiates this project from previously permitted units which have limits of 0.05 lb/MMBTU on an annual basis, it is presumed that the costs these systems will incur can also be incurred by AECI. Therefore, the economic analysis provided by AECI was not considered in selecting the NO_x limit.

Based on the performance data from other plants and NO_x BACT limits from other proposed and permitted units, the Department of Natural Resources proposes a BACT limit for NO_x emissions of 0.05 lb/MMBTU on 12-month rolling average exclusive of startup and shutdown. A shorter term BACT limit of 0.065 lb/MMBtu is also being proposed on a 30-day rolling average (also exclusive of startup and shutdown). This higher number for the 30-day rolling average is viewed as acceptable such that it allows for shorter term variability, especially at end of catalyst life conditions. This level of control equals the lowest recently permitted facilities and has been demonstrated on at least two other PC boilers firing PRB coal. In order to address higher emissions that may occur during startup and shutdown activities, a NO_x cap of 1,535 tons per year is also included. Control of NO_x will be accomplished with LNB/OFA and SCR and compliance demonstrated using CEMS.

BACT FOR PULVERIZED COAL FIRED BOILER - SO_2

Changes to the SO_2 BACT analysis for the pulverized coal-fired boiler were made prior to the issuance of the draft permit. However, these changes were inadvertently left out of the draft permit. The SO_2 BACT analysis reflects those changes as well as those resulting from Public Comments and further evaluation by MDNR.

SO_2 Control Technologies for Pulverized Coal Fired Boilers

Control Technologies

- Fuel Switching
- Coal Benefication
- Wet Flue Gas Desulfurization (WFGD)
  - lime, limestone, or magnesium enhanced lime
  - jet bubbling reactor
  - WFGD with wet electrostatic precipitator (WESP)
  - dual alkali wet scrubber
- DFGD
  - spray dryer absorber
  - dry sorbent injection
  - circulating dry scrubber

Discussion of SO_2 Control Technologies for Pulverized Coal Fired Boilers

- Fuel Switching

Fuel Switching can be used to lower the amount of sulfur in the fuel combusted. AECI has proposed a PC boiler using low-sulfur PRB coal. The design coal has low sulfur content. But, switching fuel is not consistent with the project concept and is eliminated from consideration.

- Coal Benefication

Coal benefication, or washing, can reduce both ash and sulfur from coal prior to combustion. In general, coal washing is accomplished by separating and removing inorganic impurities (FS_2 or pyrite) from organic particles. Although used on high sulfur bituminous coals, no plants have been built to wash subbituminous coals.

While washing may be effective in removing rock inclusions from coal, including sulfur bearing pyrites, a significant amount of coal may also be lost in the washing process. The inherent consequence of coal washing would be the need for the mine to process significantly more coal to make up for coal lost in the washing process and for the loss of heat content due to water added to coal fuel.

The coal washing process also generates a solid waste stream consisting of inorganic material separated from the coal, and a wastewater stream that must be treated to remove solids, coal fines, and trace metals prior to discharge. Coal slurry treatment systems may include surface impoundment, mechanical dewatering systems, chemical processing systems, and/or thermal dryers. Subbituminous coals as used in this process have excessive amount of fines, and significant dewatering equipment would be required to process and separate the fines from the wastewater steam. Moreover, the solids generated from wastewater processing and coarse material removal in the washing process must be disposed in a properly permitted landfill.

Although used on high sulfur bituminous coals, no plants have been built to wash subbituminous coals. Furthermore, the coal washing process would generate significant solid and liquid waste streams that require proper management and disposal. Therefore, coal washing is being eliminated from consideration.

- Flue Gas Desulfurization (FGD)

FGD is a post-combustion technique that removes SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated with wet, dry, or semi-dry desulfurization processes. The waste streams can either be discarded, or the reagent can be regenerated and reused.

- WFGD – These systems use alkali slurries to absorb SO_2 at a control efficiency greater than 90% for low sulfur subbituminous coals, dependent on the choice of absorbent. Control efficiency depends on control device design and operating variables. Sizing of units is dependent on whether the scrubber will be used for removal of particulate matter and SO_2, or SO_2 alone. If used for SO_2 removal solely, the unit should be placed downstream of particulate matter removal equipment. In the original BACT the removal efficiency of the WFGD was evaluated at 94%.

APCP has updated the BACT analysis using the WFGD efficiency to 95.1%. Using an adjusted maximum heat input of 6,975 MMBtu/hr and inlet sulfur dioxide emissions of 1.21 lb/MMBtu, controlled emissions would be 0.06 lb/MMBTU.

- Wet lime/limestone scrubbing – A lime/water or limestone/water slurry is sprayed in the absorber. Dewatering ponds are typically required for separation of waste products, unless forced oxidation is employed to create a saleable gypsum byproduct. Despite the need for a larger absorber and a ball mill to pulverize the limestone feed, high lime costs make limestone systems less expensive.
- Wet magnesium enhanced lime scrubbing – Magnesium oxide will increase as the soluble alkali content increases, subsequently increasing SO_2 absorption capacity. Therefore, construction of a smaller absorber is possible. However, these systems are only found where there is a source of reagent that contains the magnesium oxide naturally. There are no subbituminous coal-fired boilers utilizing these systems. These systems will not be explored further since other wet systems can achieve the same removal efficiency.
- Jet bubbling reactor (JBR) – In these systems, the flue gas is bubbled through the slurry, rather than spraying the slurry into the flue gas stream. Experience with JBR units is growing. However, although removal rates for high-sulfur coals have approached 98%, there is little experience from a large subbituminous-fired boiler on low-sulfur coals and minimal data showing enhanced performance over other wet FGD systems; JBR units will not be examined on its own, but in the context that it is considered a wet FGD system.
- Dual-Alkali Wet Scrubber – Both sodium and calcium based compounds are sprayed on the exhaust gas. The sodium-based reagent reacts with SO_2 while the calcium-based solution regenerates the spent liquor. Smaller reactor units are needed, but regeneration and sludge processing equipment is needed. Sodium-based reagents are significantly more expensive than lime or limestone, while providing equivalent control efficiency. Due to the higher reagent costs and generation of a potentially less stable sludge, dual-alkali wet scrubbers will not be examined further.
- WFGD with Wet Electrostatic Precipitator (WESP) – WESP units placed after WFGD systems allow removal of sulfuric acid mist. Particles are electrically charged, collected on a receiving surface and then washed from the surface periodically. Typically, the units are employed on units combusting high-sulfur fuels.

- DFGD – Rather than using a wet slurry, DFGD utilizes a dry or hydrated lime slurry in the exhaust stream to form calcium sulfite solids. The dry byproduct is removed using the particulate matter control device.

  - Spray Dryer Absorber (SDA) – a slurry of lime and water is sprayed into the tower so that a dry byproduct results. SDA has been used on large coal-fired units combusting low-sulfur subbituminous coals. It is expected that 93% control is possible on a long-term basis.
  - Dry Sorbent Injection – Powdered absorbent is sprayed directly into the furnace or flue gas stream. Based upon consideration of Public Comments, the control efficiencies of these simple systems was updated to control efficiencies ranging

from 40 to 85% depending on sorbent type and stoichiometry, amount of recycle, temperature and plant configuration. Since this control technology does not represent the upper level of SO_2 controls, it will not be examined further.

- Circulating Dry Scrubber – Again, hydrated lime is used to remove SO_2, but here in a circulating fluidized bed. This type of system has only been used on small pulverized coal-fired boilers; there is no operating experience for units as large as the proposed unit. Due to the limited application of the circulating dry scrubber, the assumption that removal rates would be similar to that achieved by SDA units was made. The circulating dry scrubber ought to provide 93% control over the long term.

<u>Determination of BACT for SO_2 for the Main Boiler</u>
The following table provides a summary of the technically feasible control technologies for SO_2 in descending order of control efficiency. Uncontrolled baseline emissions were calculated to be 36,420 tpy (1.21 lb/MMBTU).

Table 6 – Technically Feasible SO_2 Control Technologies

Control Technology	Emissions (lb/MMBTU)	% Reduction	Emissions Reduction (tpy)	Total Annualized Cost ($/yr)	Avg. Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
WFGD + WESP	0.06	95.1%	35,326	$49,499,400	$1,401	$22,050
WFGD	0.06	95.1%	35,155	$43,707,000	$1,243	$20,281
DFGD – Circulating Dry Scrubber	0.08	93.4%	34,016	$32,044,400	$942	
DFGD – Spray Dryer Absorber	0.08	93.4%	34,016	$20,621,200	$612	

Note: The emission rates listed are calculated assuming a heating value of 8,100 Btu/lb and 0.5% fuel sulfur content. Maximum annual emissions and annual emission reductions for the BACT analysis are based on a maximum heat input of 6,872 MMBtu/hr for the dry FGD configurations and 8,760 hours per year. Annual emissions of the WFGD configuration are calculated based on a maximum heat input of 6,975 MMBtu/hr to account for the additional auxiliary power required for the WFGD system. Annual emissions of the WFGD + WESP configuration are calculated based on a maximum heat input of 7,009 MMBtu/hr to account for the additional auxiliary power required for the WESP. The incremental cost effectiveness of the wet FGD control systems are compared to the DFGD – Spray Dryer control system.

As seen from the information contained above, the average cost effectiveness of the WFGD + WESP option is higher that the other control options. The incremental cost effectiveness of both WFGD options is substantial in comparison to either of the DFGD options. In addition to the economic impacts, there are collateral environmental and energy impacts associated with both WFGD options.

Environmental Impact

WFGD options have negative environmental impacts associated with their use. By design, water consumption would be significantly higher for a WFGD system in comparison with a DFGD system. Based on preliminary engineering calculations performed by AECI, it is estimated that the WFGD option would require at least 30%

more water that the dry system, or approximately 435 million gallons per year. It is estimated that a dry system will require approximately 620 gpm of water (325.8 million gallons per year).

WFGD options will also generate a wastewater stream that must be treated and discharged. The cost of the WFGD options as discussed above does not include the cost of treating the wastewater stream. According to the revised BACT analysis submitted on August 22, 2007, AECI would add an additional capital costs ranging from $5.5-$10.0 million dollars depending on the wastewater flow, chloride concentration in the FGD reagent and discharge. Water treatment would also add an additional $250,000 in annual operating costs to the project.

Energy Impact

Auxiliary power requirements for the wet FGD system are greater than the auxiliary power requirements of the dry FGD systems. The additional auxiliary power is needed to process limestone, which requires larger grinding equipment (Ball Mills), slurry pumps, air compressors, vacuum pumps and booster fans. This additional power requirement will reduce the unit's net plant heat rate. Consequently, heat input to the main boiler would need to increase by approximately 1.5% with the wet FGD to achieve the same net plant output. The calculated maximum heat input to the boiler with the dry FGD configuration is 6,872 MMBtu/hr. To achieve the same net output with a wet FGD the maximum heat input would need to increase to approximately 6,975 MMBtu/hr.

As discussed above, DFGD options have less significant environmental and energy impacts. The department concurs with AECI's proposal of DFGD, specifically SDA, as BACT for the Norborne boiler.

As part of the BACT analysis, AECI included a table from the analysis of the 14 coal mines in their submittal. The table outlines that the coal that is most likely to be utilized at Norborne will have a sulfur content ranging from 0.21-0.39%, and that the typical coal will have a sulfur content of 0.30%. Due to the varied range in sulfur content of the coal, the control efficiency of the DFGD is expected to be in the range from 86.0 – 93.5%. The department requested AECI to prepare a proposal for tiered SO_2 limits, dependent upon the sulfur content of the fuel. AECI has agreed with the following BACT limitations.

	SO_2 Outlet	**Inlet**	**S Content**	**Removal Efficiency**
Tier 1	0.070 lb/MMBtu	<= 0.50 lb/MMBtu	<=0.20%	86.0%
Tier 2	0.074 lb/MMBtu	0.50 < inlet SO_2 < 1.0 lb/MMBtu	0.20% < S < 0.40%	85.7% < removal efficiency < 92.3%
Tier 3	0.08 lb/MMBtu	SO_2 >=1.0 lb/MMBtu	>=0.4%	92.0% (up to 93.5% at S = 0.5%)

Please note that required removal efficiency for Tier 2 was lowered from 0.075 lb/MMBtu as stated in the draft permit to 0.074 lb/MMBtu.

BACT FOR PULVERIZED COAL FIRED BOILER – Filterable PM/PM_{10}

Filterable PM/PM_{10} Control Technologies for Pulverized Coal Fired Boilers

The following control technologies are available to reduce emissions of filterable PM/PM_{10} from pulverized coal fired boilers.

- Fabric Filtration System (Baghouse)
- Electrostatic Precipitator (ESP)

Discussion of Filterable PM/PM_{10} Control Technologies for Pulverized Coal Fired Boilers

- Fabric Filtration Systems

Baghouses use a series of bags to collect particulate matter contained in the flue gas stream. The bags are periodically cleaned when a certain level of particulate matter has been collected. Baghouses are more efficient than ESPs for collecting fine particulate. AECI has proposed a filterable PM_{10} limit of 0.015 lb/MMBTU (99.81%) when utilizing baghouses for control.

- Electrostatic Precipitators

ESPs remove particulate matter from the flue gas stream by charging fly ash particulates with a high direct current (dc) voltage and attracting these particles to charged collection plates. ESP performance is influenced by fly ash mass loading, particle size distribution, fly ash electrical resistivity, precipitator voltage and current, collection plate area, gas flow velocity, and cleaning cycle. Control can be greater than 99% for fine (less than 0.1 micrometer) and coarse (greater than 10 micrometers) particles, but reduced collection efficiencies are expected for particle diameters between 0.1 and 10 micrometers.

For subbituminous coal-fired units, ash resistivity is an effect of low sulfur concentrations, leading to reduced collection efficiencies. AECI has had to condition their flue gas streams at both their Thomas Hill and New Madrid units with SO_3, in order to achieve high filterable PM_{10} removal rates when combusting low-sulfur subbituminous coals. AECI originally stated that the highest level of removal they could achieve would result in a filterable PM_{10} emission rate of 0.018 lb/MMBTU (99.78% control).

Determination of BACT for Filterable PM/ PM_{10} for the Main Boiler

AECI has proposed use of the top control option for filterable PM/ PM_{10} control; therefore, no further evaluation of control methods is necessary. However, review of the National Coal Projects Database (June 2006 update) revealed that eight (8) projects contained filterable PM_{10} permit limits or proposed limits for utility boilers less than the level (0.015 lb/MMBTU) originally proposed by AECI, seven at 0.012 lb/MMBTU and one at 0.014 lb/MMBTU. The recently amended NSPS for utility steam generating units has a PM emission limit equal to 0.015 lb/MMBTU. The department contends that such widespread use of lower BACT limits combined with an NSPS standard for PM equivalent to AECI's originally proposed filterable PM_{10} limit are indicators that emission rates less than that proposed by AECI are achievable.

Baghouse control efficiencies can be as high as 99.99%. Although control to such an extent may be possible under certain extraordinary circumstances, there are several factors that limit fabric filtration system effectiveness to lesser levels on a long-term basis. The economics and subsequently, the efficiency of fabric filters rely on the size of the baghouse and the materials used for the filters. Extremely large systems utilizing conventional fabric bags would be expensive due to the cost of steel and the amount of real estate needed. The size of a baghouse can be decreased if the air-to-cloth ratio is increased. Smaller baghouses that can operate at increased air-to-cloth ratios are a possibility; though high-tech fabrics, like GORE-TEX® carry a much higher price tag than conventional materials. Even then, there are limitations when choosing this option.

Controlling pressure drop becomes more of a challenge with high air-to-cloth ratios. Pressure drop is dependent on two components: pressure drop across the fabric and pressure drop across the filter cake. The pressure drop across the filter cakes is dependent on the degree of cake thickness. As the flue gas passes through the fabric, the captured particulate forms a cake on the surface of the fabric. This deposit increases both the filtration efficiency and its resistance to gas flow and thus increased pressure drop through the cake. Use of GORE-TEX® fabric provides microfine pore structure while maintaining fabric permeability needed to operate under high air-to-cloth ratios. Since high-tech fabrics can provide increased removal efficiencies, the pressure drop from the filter cake can be reduced. The increased frequency of cleanings and adequate pulse energy that can prevent excessive dust cake buildup makes pulse jet baghouses attractive. But, the high energy cleaning that occurs in pulse jet baghouses can lead to significant redispersion of the dust and subsequent re-collection on the bags. Ultimately, collection efficiency is restricted because of the inherent inability of the baghouse for complete transfer of the dislodged dust to the hopper without some re-entrainment.

AECI revised their proposal for the BACT limit for filterable PM_{10} for the main boiler to 0.012 lb/MMBTU (99.85% control). MDNR concedes removal rates as high as 99.99% are not realistic on a long-term basis and, based on the discussion above, why the revised control efficiency is considered to be valid. Stack testing results from other installations shows that performance at any point in time can vary by a factor of 4. The filterable PM emission rate should not exceed 0.013 lb/MMBTU, using AP-42 guidance that 92% of PM is filterable PM_{10}.

BACT for the main boiler for filterable PM_{10}/PM is use of a fabric filtration system. Filterable PM_{10} emissions will not exceed 0.012 lb/MMBTU, while filterable PM emissions are limited to 0.013 lb/MMBTU.

BACT FOR PULVERIZED COAL FIRED BOILER - CO AND VOC

CO and VOC Control Technologies for Pulverized Coal Fired Boilers

The following control technologies exist for reduction of CO and VOC emissions.

- Combustion Modifications
  - Good Combustion Practices
- Post Combustion Modifications
  - Catalytic Oxidation
  - Thermal Oxidation

Discussion of CO and VOC Control Technologies for Pulverized Coal Fired Boilers

- Good Combustion Practices

CO emissions are the result of incomplete combustion. However, reducing CO emissions can result in an increase of NO_X emissions. CO and NO_X emissions can be balanced through the use of good combustion practices. Like CO, VOC emissions are the result of incomplete combustion of the coal. The most efficient means of controlling VOC emissions is combustion. The boiler is essentially a combustion chamber, and as such, the proper operation of the boiler through the use of good combustion practices will promote complete combustion. Good combustion practices include extended residence time, proper mixing of air and fuel, and steady high temperatures in the combustion zone.

- Catalytic Oxidation

Catalytic oxidation systems are used to oxidize both CO and VOCs to CO_2 and water. Although catalytic oxidation is currently used for gas turbines and refinery operations, no coal-fired boilers operate with them. Sulfur compounds in the flue gas can deactivate the catalyst used and particulate matter entrained in the flue gas would foul and poison the catalyst. Placement of the catalytic oxidation unit would have to be downstream of the particulate matter control device. By placing the unit at that location, the exhaust stream would need to be reheated, causing increases in both NO_x and PM_{10} emissions. Operating conditions of the catalyst also favor the conversion of SO_2 to SO_3 and subsequent sulfuric acid mist generation. Catalytic oxidation is neither technically feasible nor commercially available.

- Thermal Oxidation

Thermal oxidizers must operate at much higher temperatures since there is no catalyst. If the thermal oxidation unit is placed prior to the particulate matter control device, plugging and fouling of fans and ductwork would occur. Placement of the unit after the particulate matter control device would require reheating of the exhaust stream. Again, combustion of additional fuel for reheating of the exhaust stream would result in additional emissions of NO_X and PM_{10}. There are no installations of thermal oxidizers on coal-fired power plants. Because this technology has not been used on coal-fired power plants or any other stationary source applications of this magnitude, thermal oxidation is not considered to be technically feasible and is not commercially available.

<u>Determination of BACT for CO for the Main Boiler</u>

AECI has proposed, and the Department concurs, that good combustion practices constitute BACT for controlling CO emissions out of the main boiler. AECI has proposed emission limits of 0.16 lb/MMBTU for CO. AECI stated in its BACT analysis that to achieve a proposed rate of 0.35 lb/MMBTU NO_X exiting the boiler (0.08 lb/MMBTU exiting the stack, post-SCR), CO emissions could only be reduced to 0.16 lb/MMBTU. A trade-off does exist between NO_X and CO emissions. However, in reviewing the information supplied by AECI on other recent BACT determinations for NO_X and CO, several recently permitted plants have limits lower than what AECI has proposed. Four of the five units listed in AECI's Tables A-1 and A-4 employing LNB have CO limits below AECI's proposed limit; three of these also have NO_X limits exiting the stack lower than AECI's proposed limit. Additionally, only three of the sixteen units found in the table have the same limit as AECI's proposed limit and no installation has a higher limit, regardless of the type of NO_X controls employed.

Due to the large number of installations with lower limits, the Department has revised the BACT limit downward to 0.15 lb/MMBTU on a 30-day rolling average (based on installations with a NO_X limit exiting the stack of 0.07 lb/MMBTU).

Determination of BACT for VOC for the Main Boiler

AECI has proposed, and the Department concurs, that good combustion practices constitute BACT for controlling VOC emissions out of the main boiler. AECI originally proposed a BACT limit of 0.0038 lb/MMBTU for VOCs. However, an analysis of other recent BACT determinations submitted by AECI showed that ten of those units have lower VOC limits than what was originally proposed by AECI. Again, the Department believed that a lower limit might be achievable in AECI's case.

AECI's proposal was based on an AP-42 emission factor of 0.06 pounds per ton of coal feed and a design heating value of coal equal to 8,000 Btu/lb. However, since AP-42 publishes emission factors averaged from several facilities, the values cannot automatically be considered indicative of the lowest emission rates possible. AECI subsequently submitted additional information in support of using the AP-42 emission factor.

Of the seven plants with VOC limits lower than 0.0038 lb/MMBTU, three of those plants, Spruce 2, Santee Cooper and Elm Road Station, required LAER limits for VOC. One of those, Santee Cooper, used the AP-42 emission factor when establishing their LAER limit (the heating value of the other two is unknown). Three additional plants, Intermountain, LS Longleaf and Roundup Power also used the AP-42 emission factor as basis for their VOC BACT limit. There are multiple instances in which the BACT limit is equivalent to the emission rate derived using the AP-42 emission factor and the heating value of the specific design coal.

AECI also contends that since AP-42 emission factors are derived from stack testing conducted at operating facilities, they represent actual emissions. As such, setting a BACT limit using the AP-42 emission factor forces the plant's actual emission rates to be lower to insure compliance. Additionally, AECI asserts that since VOC emissions are typically measured using stack tests, operational data is not as easily accessible as it is for NO_X, SO_2 or CO emissions. The Department believes these are valid points.

Due to the prevalent use of the VOC AP-42 emission factor in setting BACT limits for utilities and the absence of available data to negate the emission factor's validity, the AP-42 emission factor is considered a valid choice. Although AECI's emission rate limit using the AP-42 emission factor would be 0.0037 lb/MMBTU, AECI has revised its proposed emission rate limit to a lower level. The BACT limit for VOC for the main boiler using good combustion practices is set at 0.0036 lb/MMBTU.

BACT FOR PULVERIZED COAL FIRED BOILER - SAM

Sulfuric acid mist (SAM) emissions are a result of SO_2 in the flue gas stream oxidizing to SO_3, then forming H_2SO_4 when in contact with moisture. SAM, in addition to being a PSD pollutant, is a constituent of condensable particulate matter (CPM). SO_3 will be generated by combustion in the boiler and oxidation by the SCR catalyst. Approximately 2.0 percent of the fuel SO_2 could be converted to SO_3 in the boiler and SCR, and then to SAM, or equivalent to a maximum uncontrolled rate of 0.0378 lb/MMBTU.

Ammonium sulfate, $(NH_4)_2SO_4$, can also form from SO_3 by combining with ammonia from the SCR unit. No data has been found to determine what portion of the SO_3 will form SAM and what portion will form ammonium sulfate. Therefore, for purposes of this BACT analysis, it was presumed that no ammonia sulfate is formed (i.e., only SAM will be emitted).

Although not PSD pollutants, ammonium sulfate, HCl and HF emissions can be reduced using the same control devices applicable to SAM, at about the same efficiency.

<u>SAM Control Technologies for Pulverized Coal Fired Boilers</u>
The following control technologies exist for reduction of SAM.

- Fabric Filtration System (Baghouse) + DFGD
- WFGD
- Alkali Injection System
- Wet Electrostatic Precipitation (WESP)

<u>Discussion of SAM Control Technologies for Pulverized Coal Fired Boilers</u>

- Fabric Filtration System + DFGD

Within the fabric filtration system, fly ash cake accumulates on the filter bags, providing an alkaline filter through which the flue gas must pass. Subbituminous PRB coal provides highly alkaline fly ash well suited for this purpose. Meanwhile, SO_3 will react with the lime in the DFGD to form calcium sulfate. The alkalinity of the filter cake in the baghouse is enhanced by the DFGD reactant deposited on the filter bags. Fabric filters and DFGD combined can provide SAM removal rates of 90% (equivalent to 1.5 ppmvd @ 3% O_2). For PC-fired boilers firing low-sulfur, subbituminous coals, this is the top control method.

- WFGD

WFGD, on the other hand, is not nearly as effective for SAM control. Aerosols of fine SAM are formed when entering the WFGD system. Most of these aerosols are in the range of 0.1 and 0.5 microns. Most of these particles will escape capture in the WFGD since particle impaction and separation forces are negligible for the conditions prevailing in the scrubber. AECI contends that WFGD control of SAM will reduce emissions by only 40%.

- Alkali Injection System

Alkali injection, or dry sorbent injection (DSI), systems place dry alkaline material directly into the gas stream upstream of the baghouse. Like DFGD systems, DSI systems will increase the alkalinity of the filter cake in the baghouse. Some systems can achieve stack outlet SAM emissions of less than 2 ppmv. Use of a DSI system would be redundant to using the DFGD AECI has proposed for SO_2 removal. Therefore, use of a DSI system will not be evaluated further.

- Wet Electrostatic Precipitation (WESP)

For coal plants burning high sulfur bituminous coal that have WFGD systems installed, installing a wet electrostatic precipitation (WESP) unit is the next logical step to reduce SAM/CPM emissions. However, there is limited experience for operating a WESP on a low-sulfur fuel boiler for SAM control. Northern State Power's Shirco Station is the only existing U.S. installation that burns subbituminous coal and employs a WESP for reducing opacity. Data from that plant has shown opacity to be reduced to less than 10%. It is known from experience that for each ppmv of SO_3 leaving the stack as sulfuric acid, its contribution to plume opacity is around one percentage point, i.e., 15 ppmv of SO_3 leaving the stack equates to around 15% opacity. Therefore, Shirco Station's decrease in opacity to somewhere less than 10% equates to SAM emissions a little less than 10 ppmv. There are no plants using fabric filters and DFGD firing low-sulfur subbituminous coal using WESP; it is not considered commercially available for AECI's application.

<u>Determination of BACT for SAM for the Main Boiler</u>
AECI has proposed the top control option for SAM removal, fabric filtration system and DFGD. The department concurs with AECI's proposed limit and finds it among the lowest in the country, according to the RBLC database. One permit exists with a significantly lower limit for SAM. The 0.000184 lb/MMBTU SAM limit that is found in the City Utilities permit was proposed by the applicant and did not undergo a BACT evaluation. During the course of this review, that limit has been determined to be not achievable in AECI's case. It was determined using the assumption that a different method for testing was going to be used to show compliance with the limit. City Utilities is currently under construction and have not demonstrated compliance.

BACT for SAM is the use of fabric filtration and DFGD with emissions limited to 0.0038 lb/MMBTU on a 30-day rolling average. This limit is amongst the lowest in the country, exclusive of the City Utilities permit.

<u>BACT FOR TOTAL PM_{10}</u>
PM_{10} is comprised of both filterable and condensable fractions. The filterable fraction is what is known as the "front half" of the sampling train, while condensable PM_{10} makes up the "back half". This "back half" partly consists of materials in the flue gas that can exist as vapors at stack temperatures but condense to liquid or solid aerosols at ambient temperatures. As mentioned previously, CPM constituents from the main boiler are SAM, ammonium sulfate, HCl, HF and VOC.

As discussed in the SAM BACT analysis above, SO_3 can convert to either SAM or ammonium sulfate. For purposes of this analysis, it was presumed that all SO_3 converted to SAM. The SAM contribution to CPM was determined to be 0.0038 lb/MMBTU; as such, there is no ammonium sulfate contribution.
The following portion of the draft permit was used to support a Total PM_{10} limit of 0.024 lb/MMBtu. Due to Public Comments and further evaluation by the Air Pollution Control Program, the Total PM_{10} limit has been updated to 0.018 lb/MMBtu. See Response to Comments for further discussion.

HCl and HF, although constituents of CPM, are not PSD pollutants subject to BACT. HCl and HF emissions are dependent on the chlorine and fluorine concentrations in the PRB coal. The uncontrolled concentrations are equivalent to 397 ppmd (0.0342 lb/MMBTU) and 120 ppmd (0.0106 lb/MMBTU), respectively. These concentrations were taken from the coal mine analysis supplied by the applicant. The fabric filter and DFGD should control these emissions at the same 90% removal rate that is used for SAM emissions. Therefore, the controlled emissions of HCl and HF should not exceed 0.0034 lb/MMBTU and 0.0011 lb/MMBTU, respectively. It should be noted that although fabric filtration and DFGD will control emissions of SAM, ammonium sulfate, HCl and HF, both control devices intentionally must be operated in a way that will maximize removal of filterable particulate matter and SO_2 emissions. Removal of any other pollutant is secondary.

VOCs are the final constituent of CPM. The BACT analysis resulted in a VOC limit equivalent to 0.0036 lb/MMBTU. Summing the contributions of each CPM constituent, AECI's CPM emissions are not expected to exceed 0.012 lb/MMBTU. Total PM_{10} emissions (condensable + filterable) are then 0.024 lb/MMBTU.

This limit is higher than the 0.018 lb/MMBTU value found in several recently permitted plants. AECI does not feel that attainment of 0.018 lb/MMBTU is possible, primarily due to potential biases of using Method 202, EPA's CPM test method. Several recent projects have addressed the same concern in a variety of ways. Many of the permits that have limited total PM_{10} emissions to 0.018 lb/MMBTU also allow for alternate test methods to be used to demonstrate compliance with their limit (e.g., Thoroughbred, Trimble Cty., Elm Road, Weston 4). There are other permits (e.g., Prairie State, Comanche) that allow for the limit to be lowered should the unit perform well during stack testing. Finally, there are permits (e.g., Duke Energy Cliffside Unit 6, Sunflower) that have proposed emission rate limits for total PM_{10}, but have included language that allows the limit to be raised should the plant demonstrate that attainment of the proposed value is not possible.

Comparison to other limits in the RBLC and the National Coal Projects database is made difficult when the established test method allows alteration. No longer can an "apples-to-apples" comparison be made, since specific changes to the test method may vary from unit to unit. The remaining two scenarios, those that include "just in case" limits, also make a valid comparison between plants impossible. The Department feels that these "just in case" limits should be considered the BACT limits that are used for purposes of comparison between plants. It should be noted that since higher limits are already incorporated into these permits, no additional public notice or review would be required, regardless of stack testing results.

Therefore, when using the higher "just in case" limits for comparison,

> Duke's total PM_{10} limit is then 0.024 lb/MMBTU. Prairie State and Sunflower are limited to 0.035 lb/MMBTU. As stated previously, valid comparison cannot be made with other plants that allow modifications to Method 202. What remains available for comparison is a small handful of plants that have proposed or been permitted with a total PM_{10} limit equal to 0.018 lb/MMBTU using unaltered Method 202 for compliance. These plants have not yet begun operation; attainment of such low total PM_{10} limits has not yet been demonstrated.

As previously stated, total PM_{10} consists of both filterable and condensable PM_{10} fractions. BACT for total PM_{10} from AECI's main boiler will consist of baghouse and DFGD control for the CPM constituents, exclusive of VOC; the VOC constituent is controlled with good combustion practices. The filterable portion of total PM_{10} will be controlled using a fabric filtration system. The total PM_{10} BACT limit is determined to be 0.018 lb/MMBTU. This limit is consistent with emission rates proposed and achieved at other facilities.

BACT FOR AUXILIARY BOILER

Emissions from the auxiliary boiler will include the same criteria pollutants as those from the main boiler: PM_{10}, SO_2, NO_X, VOC, CO, and SAM.

PM/PM_{10}

PM/PM_{10} emissions from the auxiliary boiler are a result of incomplete combustion of the distillate oil fuel. Ash content of distillate oils is negligible and will not noticeably affect the amount of PM/PM_{10} emissions from the boiler. Flue gas recirculation used for NO_X control and good combustion practices employed for VOC and CO control, also tend to lower particulate matter emissions.

Baghouses are not considered a technically viable option for the oil-fired boiler since the "sticky" PM emitted from such units sticks to the fabric and creates a fire safety hazard. Cyclonic collectors are also not considered to be highly effective when used on boilers firing clean oils, since low sulfur distillate oil will generate minimal particulate matter emissions and high percentage of the particulate matter will be $_{PM10}$. Likewise, scrubbing systems will have a significant drop in effectiveness (from a maximum of around 60%) due to the low quantity of PM_{10} emissions resulting from distillate oil combustion. These methods of control were eliminated from further review. ESPs can remove up to 90% of PM for units firing residual oils. It is expected that control efficiency for an ESP placed on a distillate oil-fired boiler will be less, since the PM_{10} emission rate is inherently low. A collection efficiency of 70% is more realistic. An economic evaluation of ESP use resulted in a cost per ton of removal exceeding $100,000. Therefore, ESPs are rejected due to economic infeasibility. BACT for PM/PM_{10} for the distillate oil-fired auxiliary boiler is considered to be flue gas recirculation and good combustion practices.

BACT for filterable PM_{10} emissions is 0.007 lb/MMBTU and for total PM_{10} is 0.016

lb/MMBTU. AECI had initially proposed using 0.014 lb/MMBTU and 0.0234 lb/MMBTU for the filterable PM_{10} and total PM_{10} limits, respectively; however, those values assumed that all of the PM emitted by the boiler would be PM_{10}. AECI employed the cumulative particle size distribution that is found in Table 1.3-6 of AP-42's section on distillate oil combustion to adjust the proposed numbers downward. The revised limits are in line with other recent BACT determinations.

<u>SO_2 and SAM</u>
Sulfur oxide and sulfuric acid mist emissions from the auxiliary boiler are dependent only on the sulfur content of the fuel being combusted. AECI will be combusting only distillate oil fuel with a sulfur content of no more than 0.05%. Assuming that all sulfur is converted to SO_2, the SO_2 emission rate equals 0.0524 lb/MMBTU. If 5% of the sulfur in the fuel would then convert to SO_3, and 100% of the SO_3 would convert to H_2SO_4, the emission rate for H_2SO_4 is 0.004 lb/MMBTU, based on mass balance calculations. Although placing a FGD system on the auxiliary boiler would be technically feasible, due to the characteristics of the flue stream gas, FGD has no practical application to a distillate oil-fired boiler. BACT for SO_2 is considered to be an emission rate of 0.0524 lb/MMBTU. BACT for H_2SO_4 is considered to be an emission rate of 0.004 lb/MMBTU.

<u>NO_x</u>
AECI has proposed LNB and FGR as BACT for NO_X. SCR, combined with LNB and FGR, is the top control method. Although SCR is a technically feasible control for further NO_X reductions, the cost per ton of NO_X removal increases drastically on a cost per ton basis from approximately $7,700 with LNB and FGR to over $14,700 with SCR. The Merck & Company West Point Plant units are the only oil-fired industrial boilers located in the RBLC database permitted with SCR. However, those units were required to comply with LAER. Due to economic impacts and no other non-LAER units operating with SCRs, use of SCR for AECI is rejected as BACT.

AECI will utilize LNB and FGR as BACT with a limit of 0.10 lb/MMBTU. The final 0.10 lb/MMBTU limit is among the lowest limits found for auxiliary boilers undergoing BACT review; only units undergoing LAER are lower.

<u>VOC and CO</u>
VOC and CO emissions result from incomplete combustion. Therefore, by improving the combustion efficiency of the boiler, emissions of these two pollutants will decrease. Good combustion practices (GCP) is the generic term used to describe the work practices utilized by boiler operators to minimize the quantity of incompletely combusted fuel. GCP are part of each installation's normal operating procedures, due to the negative economic impacts associated with excessive fuel use resulting from incomplete combustion. Catalytic oxidation, a post-combustion control, can further reduce VOC and CO emissions. However, catalytic oxidation is not considered to be technically feasible for distillate oil-fired boilers that modulate or cycle frequently. In addition, catalytic oxidation systems have not been used to control CO/VOC emissions from distillate oil-fired auxiliary boilers. AECI would incur significant engineering and testing to ensure viability. Therefore, on either basis, consideration of this technology can be rejected. AECI proposed to utilize GCP to reduce VOC and CO emission levels to 0.005 lb/MMBTU and 100 ppmvd @ 3% O_2 (0.08 lb/MMBTU), respectively.

Decreases in CO emissions are bound, in part, by the NO_X limitation set for the boiler. NO_X emissions can only be reduced by a certain fraction before CO emissions will begin to increase. Although the proposed CO BACT limit is not the lowest permitted level that is found in the RBLC database, it is in line with other facilities having similar NO_x BACT limitations. The Department agrees with both the proposed VOC and CO BACT determinations.

BACT FOR EMERGENCY GENERATOR, FIRE WATER PUMP and FIRE WATER BOOSTER PUMP

The emergency generator and fire water pumps will emit PM_{10}, SO_2, NO_X, VOC and CO on an intermittent basis. All three compression ignition (CI) internal combustion engines (ICEs) will be fueled by low-sulfur (0.05%, by weight) diesel fuel, resulting in minimal SO_2 and SAM emissions. BACT for the remaining pollutants consists of combustion controls, including injection timing retard and minimizing air-to-fuel ratio.

Post-combustion control options were considered in the BACT analysis, however, none of these options was determined to be feasible due to either technical or economic reasoning. Non-selective catalytic reduction (NSCR), used for NO_X removal is most effective for fuel-rich systems; AECI will be using lean-burn engines. Lean-NO_X catalyst has problems with the durability of substructures in the NSCR. Diesel particulate filters used for PM removal have to regenerate using too high of temperatures, which may lead to uncontrolled ignition of soot or filter substrate damamge. AECI made use of the EPA's economic impact evaluations conducted during the rulemaking process for the CI ICE NSPS. These timely analyses were determined to be appropriate for AECI's BACT analysis. Those analyses demonstrated that NO_X absorbers and SCR are cost prohibitive for NO_X removal and that catalytic diesel particulate filters (CDPF) and oxidation catalysts are economically infeasible for PM reduction. Each of these post-combustion control methods would cost AECI at a minimum $13,000 per ton of NO_X removed and could easily exceed $300,000 per ton of PM removed.

AECI has proposed using the newly promulgated NSPS CI ICE limits as basis for the BACT limits for NO_X, CO and PM_{10}. Upon subtracting the VOC portion of emissions from the CI ICE NSPS limit for NO_X + NMHC, the NO_X portion corresponds to the lowest limit found for emergency generators and fire water pumps in the RBLC on a lb/MMBTU basis. AP-42 provided a basis for the VOC portion of emissions. Compliance with the NSPS standard for NO_X + NMHC is considered to be acceptable for demonstrating compliance with the NO_X and VOC limits. The proposed PM_{10} limit is based on the NSPS limit for PM adjusted according to available particle size distribution data, and is also among the lowest limits found in the RBLC. SO_2 and H_2SO_4 emissions limits were based on mass balance calculations of burning low sulfur (0.05% sulfur, by weight) fuel, in the same manner as for the auxiliary boiler.

BACT FOR EVAPORATIVE COOLING TOWERS – Filterable PM_{10}

Evaporative cooling towers are heat exchangers used to dissipate large heat loads to the atmosphere by crossing cooling water with ambient air. Since cooling water comes into direct contact with the air passing through the tower, some of the liquid water is carried out as "drift". Particulate emissions occur as a result of the solids in the water leaving the cooling tower as drift. The level of drift is dependent on the fill design, the air and water patterns, and tower maintenance and operation levels. Drift eliminators are incorporated into the design of the towers to reduce the amount of drift.

AECI – Norborne will utilize high efficiency drift eliminators designed to reduce the level of drift from the cooling towers to 0.0005% of the circulating water flow rate. Potential emissions from the cooling tower will be reduced by more than 99%. Although AECI – Norborne originally proposed drift reduction equivalent to 0.001% of the circulating water flow rate, installations with the lower level of drift have been permitted, thus the lower level was determined to be achievable and deemed as BACT. Since operational factors also play a part in determining drift levels, the installation will also monitor the circulating water flow rate and the level of total dissolved solids to ensure that the rate of emissions does not exceed the rate used in determining potential to emit.

BACT FOR HAUL ROADS – Filterable PM_{10}

BACT for the haul roads, with the exception of the landfill haul road, was determined to be the paving and periodically washing the roads. This represents the highest level of filterable PM_{10} control, and as such no further evaluation was conducted for other control technologies.

The haul road running from the edge of the landfill onto the landfill itself will not be paved. Paving of the landfill haul road is not feasible in that the road changes as the landfill utilization changes. Dozer traffic will occur in the active areas of the landfill as waste material is added and landfill cover is put in place. BACT for the landfill haul road and for the active dozing areas was determined to be either the application of chemical surfactant or documented watering to achieve a control efficiency of 90 percent.

BACT FOR STORAGE PILES – Filterable PM_{10}

BACT for the storage piles will also consist of chemical surfactant or documented watering of the vehicular activity areas of the storage piles. These vehicular activity areas include all areas between and within the active piles and the inactive pile that could be used during coal transfer between the piles or individual pile maintenance.

BACT FOR MATERIAL HANDLING PROCESSES

BACT for the material handling transfer points was determined to be a combination of spray dust suppression, enclosures, and baghouses. All baghouses used to control emissions from the material handling system will have a maximum outlet emission rate of 0.005 grains per dry standard cubic foot (gr/dscf). The following control methods represent BACT for the material handling processes:

- Railcar unloading emissions will be controlled by baghouses;
- Transfer of coal from the railcar unloading to the storage pile will be controlled by a combination of enclosure and wet suppression with dust control chemicals;
- Coal reclaim hopper will be controlled by enclosure and dust control chemicals;
- All coal crushing is located within the coal crusher house and vented to two baghouses;
- The coal tripper house is vented to a baghouse;
- The waste ash storage silos are vented to baghouses and vacuum exhausters;
- The fly ash loadout is partially enclosed;

- The recycled ash storage silos' emissions are controlled by a baghouse and vacuum exhausters;
- The bottom ash bunker and truck loadout to landfill is controlled by water addition;
- The lime unloading to storage silo from the truck will be controlled by a baghouse; and
- The activated carbon storage silo will be controlled by a baghouse.

BACT FOR TANKS – VOC

VOC emissions totaling less than 1 ton per year are expected from the fuel storage tanks (T-01, -02, -03 and -06). The tanks that store hydraulic fluid (T-05) and lube oil (T-04) are part of closed loop systems and no emissions are expected from these tanks. AECI is proposing vertical fixed roof storage tanks constructed to meet applicable industry code for the storage of flammable and combustible liquids. Because the VOC emissions are expected to be insignificant, no additional BACT controls are required.

AMBIENT AIR QUALITY IMPACT ANALYSIS

AECI submitted a Class I and Class II Ambient Air Quality Impact Analysis (AAQIA). The Class I AAQIA was for Hercules Glades. Based upon the model reviewed by the Air Pollution Control Program staff, the study submitted by AECI is complete and demonstrates that AECI will not contribute to any violation of the National Ambient Air Quality Standards (NAAQS) or available increment. For a more thorough discussion of the modeling methodology used and the results, please refer to the attached memorandums entitled, *Ambient Air Quality Impact Analysis (AAQIA) for Associated Electric Cooperative, Inc. Norborne Power Plant, Prevention of Significant Deterioration (PSD) Modeling dated October 10, 2007 and Class I Ambient Air Quality Impact Analysis (AAQIA) for Associated Electric Cooperative, Inc. (AECI) August 2007* Su*bmittal dated October 10, 2007.*

STAFF RECOMMENDATION

On the basis of this review conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, I recommend this permit be granted with special conditions.

______________________________ _______________________
Susan Heckenkamp Date
Environmental Engineer

PERMIT DOCUMENTS

The following documents are incorporated by reference into this permit:

- The Application for Authority to Construct form, dated January 25, 2006, received January 30, 2006, designating Associated Electric Cooperative, Inc. as the owner and operator of the installation.
- Northeast Regional Office Site Survey, dated September 7, 2006.
- “Simplified Process Flow Diagrams” Exhibit 1-1, received via email January 26, 2006.
- Revision 1 to Section 5, Regulatory Review, of application, dated January 25, 2006, received January 30, 2006.
- Replacement of Authority to Construct forms 2.0, 2.1, 2.3, 2.5, 2.7, 2.8, 2.T, received January 30, 2006.
- Revision to “Simplified Process Flow Diagrams” Exhibit 1-1, received via email February 16, 2006.
- Appendix A – Powder River Basin Coal Analysis, dated April 13, 2006, received April 17, 2006.
- Revision to “Simplified Process Flow Diagrams” Exhibit 1-1, received February 16. 2006.
- Revision to “Simplified Process Flow Diagrams” Exhibit 1-1, received via email April 28. 2006.
- Revision to “Simplified Process Flow Diagrams” Exhibit 1-1, dated May 19, 2006, received May 22, 2006.
- Revision to Table of Contents, Sections 1, 2, 3, and 4 of permit application, received May 30, 2006.
- Updated Form 2.0s, received May 30,2006
- “Material Handling System Inputs to Air Quality Modeling”, dated April 27, 2006, received May 30, 2006.
- “Information Request for the Norborne Permit Application – Explanation of Emission Points and Associated Transfer Points and Applied Controls, received May 30, 2006
- Appendix B – Norborne Auxiliary Tank Throughput Analysis, dated May 25, 2006, received May 30, 2006
- Forms 2.0 and 2.7 for Activated Carbon System, received via email June 23, 2006.
- Revision 1 to Section 3, BACT Analysis, received June 29, 2006
- Revision 1 to Section 6, BACT Analysis, dated August 28, 2006, received August 31, 2006.
- Revision to Exhibit 3.1, Plant Layout Drawing, received via email September 20, 2007.
- Revision 2 to Section 4, New Emissions, dated September 18, 2006, received September 20, 2006.
- Revision 3 to Section 4, New Emissions, dated September 21, 2006, received September 29, 2006.
- Revision 1 to Section 9, BACT Analysis, dated September 21, 2006, received September 29, 2006.
- Supplemental Response to MDNR BACT Questions, dated November 8, 2006, received November 15, 2006.

- Updated Material Handling and Haul Road Information, entitled Norborne SRCs-rev2.xls, received via email December 8, 2006.
- Materials Handling System Emission Calculations, dated December 15, 2006, received via email December 19, 2006.
- Original Process Flow Diagrams, Exhibit 1.1Jan2007-a, received via email January 8, 2007.
- Revision to Process Flow Diagrams, Exhibit 1.1Jan2007-a, received via email January 11, 2007.
- Norborne Emissions Summary, received via email January 11, 2007.
- Information Concerning the AECI Norborne Project – SO_2, NOx and PM_{10} Permit Limits, dated February 14, 2007, received February 20, 2007.
- Responses to MDNR Comments and Questions on Norborne Material Handling Emission Calculations, dated March 19, 2007, received via email March 20, 2007.
- Revision 1 to Section 10, Additional Impact Analysis, dated March 2007, received March 23, 2007.
- Norborne New Coal Plant Material Handling Emission Calculations and Spreadsheet, dated and received April 18, 2007.
- Revision to Process Flow Diagrams, Exhibit 1.1-20/Apr2007-a, received via email April 23, 2007.
- Updated SO_2 Control System BACT Cost Effectiveness Analysis, received via email August 9, 2007.
- FGD Wastewater Treatment System, received via email August 9, 2007
- Norborne Power Plant Additional Impacts Analysis and Air Quality Related Values Revised Impacts Analysis, dated June 22, 2007, received June 26, 2007
- MDNR's Comments and Responses on Associated Electric Cooperative, Inc. 660-MW Pulverized Coal Fired Generating Facility
- AECI's Response to Comments on Draft PSD Permit for Proposed Norborne, dated January 4, 2008, received January 8, 2008
- Supplemental Responses by AECI to Comments Submitted on PSD Permit for Proposed Norborne Facility, dated January 9, 2008, received January 10 2008
- Response on 30-day Average received via email on January 14, 2008
- DFGD Variance received via email on February 22, 2008