

## **APPENDIX A**

**Technical Feasibility Assessment Details for NO<sub>x</sub> Controls (A1)**

**Cost Estimate Details for NO<sub>x</sub> Controls (A2)**

**U.S. Coal Cyclone NO<sub>x</sub> Reduction Projects Summary (A3)**

**Retrofit NO<sub>x</sub> Control Projects' Technical Literature Summary (A4)**

**EERC Report – Ash Impacts on SCR Catalyst Performance (A5)**

## **A1 Technical Feasibility Assessment of NO<sub>x</sub> Control Alternatives**

### **A1.1 Pre-Combustion Controls – Fuel Switching/Blending**

Fuel switching can be a viable method of NO<sub>x</sub> emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of Leland Olds Station, the Unit 1 and Unit 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a low fuel higher heating value (Btu/lb), medium to high ash, and high moisture content. Based on available emission data for LOS, switching fuel from a lignite/PRB coal blend to 100% PRB coal is expected to yield little or no significant additional NO<sub>x</sub> reduction. Ottertail Power Company's Big Stone Unit 1's boiler, located in South Dakota, was originally designed to burn northern Midwest lignite, and has cyclone furnaces and the same physical size and arrangement as LOS Unit 2's boiler. Big Stone Unit 1's boiler was converted from firing lignite to PRB coal in 1997. Based on available EPA Acid Rain Program's Clean Air Market Division (CAMD) emission data for Big Stone Unit 1, switching fuel from a lignite coal to PRB coal is the expected to yield no significant additional NO<sub>x</sub> emissions reduction relative to current baseline levels for Unit 2 at Leland Olds Station.

Conversion of Leland Olds Station Unit 1 and Unit 2 to fire lignite/western subbituminous coal blends up to 100% PRB coal is technically possible. It is expected that various off-site, plant site, and powerplant modifications will be required. This has not been closely examined for all aspects of design, construction, operation and maintenance. A relatively modest quantity of PRB coal is currently burned annually at this plant. Rail service is presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal are expected to be of modest significance. This is described in more detail in the main report, Section 2.4.1.5 for LOS Unit 1 and Section 2.5.1.5 for LOS Unit 2. PRB coal cost (delivered) will be approximately 60% more per ton or 29% more per mmBtu delivered than North Dakota lignite from Basin Electric's existing source. However, with such a negligible amount of NO<sub>x</sub> emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other technologies that offer similar or better results expected for a much lower combination of capital and operational costs. This alternative was not included in the NO<sub>x</sub> control cost-effectiveness analysis.

## **A1.2 Combustion Controls**

Nitrogen oxides (NO<sub>x</sub>) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. Nitrogen oxide (NO) is the most predominant form of NO<sub>x</sub> emissions, along with nitrogen dioxide (NO<sub>2</sub>). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces very high uncontrolled NO<sub>x</sub> emissions.

Combustion controls employ methods that reduce the amount of NO<sub>x</sub> emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). This results in fewer emissions that may require subsequent reduction from applicable post-combustion techniques.

### **A1.2.1 Basic Combustion Improvements**

Combustion improvements are commonly-applied, combustion-related NO<sub>x</sub> emission reduction techniques. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio<sup>1</sup>.

These improvements may allow, or be combined with, a technique called “low excess air” (LEA) operation of the pulverized lignite burners or cyclones, where a slight decrease in the total amount of combustion air is supplied to the burners, thus reducing the amount of thermal NO<sub>x</sub> emissions produced during combustion. Other operational techniques to reduce NO<sub>x</sub> emissions may utilize burners out-of-service (BOOS) and biased firing (BF). With BOOS, selected burners are removed from service by stopping fuel flow but maintaining airflow, so as to force the remaining active (i.e. firing) burners or cyclones to operate fuel-rich, thus promoting lower NO<sub>x</sub> emissions. In biased firing, often the lower burners or cyclones are operated with more fuel than the upper levels, which also produces low excess air or “fuel-rich” combustion conditions in the lower burners. These basic techniques are often applied prior to, or along with, other combustion techniques and technologies associated with NO<sub>x</sub> emission control. The amount of potential NO<sub>x</sub> emission reduction is highly-dependent on the specific type of firing, fuel,

and conditions which apply to the boiler(s) being reviewed. Typically, the operation of burners in an air-starved, fuel-rich mode is similar to that included as part of separated overfire air system implementation.

Significant additional long-term NO<sub>x</sub> emissions reduction at LOS from these improvements is not expected. Improvements to the operation of the combustion equipment in a manner that allows modest amounts of burner/cyclone air staging, along with reducing combustion air inputs have already decreased pre-control baseline annual average NO<sub>x</sub> emissions. This will subsequently affect (limit) the amount of further NO<sub>x</sub> reduction possible from these basic combustion improvements. The benefits from this alternative were assumed to be included in the alternatives involving separated overfire air. This alternative was eliminated from consideration as a separate stand-alone option for additional NO<sub>x</sub> reduction at LOS Station.

#### **A1.2.2 Low-NO<sub>x</sub> Burners (LNB)**

Low NO<sub>x</sub> burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. These are often, but not always, installed with some form of overfire air to allow for air-staged or “starved air” combustion to lower NO<sub>x</sub> emissions. LOS Unit 1 already has low NO<sub>x</sub> burners suitable for good combustion performance and low NO<sub>x</sub> emissions with pulverized lignite fuel. Installed low-NO<sub>x</sub> burners at Leland Olds Station Unit 1 with close-coupled overfire air have already decreased pre-control baseline annual average NO<sub>x</sub> emissions to approximately 0.29 lb/mmBtu. Installing the latest multi-zone LNBs would not be expected to significantly lower NO<sub>x</sub> emissions without potentially introducing adverse operational consequences, such as unstable pulverized fuel ignition and high unburned carbon content in the boiler’s particulate emissions.

LNBs are not applicable to cyclone-fired boilers<sup>1</sup>. This is due to the physical constraints imposed by the cyclone furnaces’ (barrels) length and diameter, and the incompatibility with the amount of heat released and flame dispersion patterns, and insufficient amount of fine coal particles required to sustain stable combustion associated with air-staged firing of coal using low-NO<sub>x</sub> burners with pulverized fuel. This alternative was eliminated from consideration for potential additional NO<sub>x</sub> emissions reductions from LOS boilers.

### **A1.2.3 Separated Overfire Air (SOFA)**

Separated overfire air (SOFA) is a commonly-applied, combustion-related NO<sub>x</sub> emission reduction technology. Separated Overfire Air (SOFA) is an air-staging NO<sub>x</sub> reduction technique that is usually based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. LOS Unit 1 operates with close-coupled overfire air (CCOFA), which has ports that are closer in vertical distance above the top row burners than optimized separated overfire air ports. It is believed that LOS Unit 1's boiler would be a suitable candidate for the installation of SOFA and removal of CCOFA ports for additional NO<sub>x</sub> control, if this is necessary. This technology is feasible for LOS Unit 1's boiler if NO<sub>x</sub> control beyond the presumptive BART level of 0.29 lb/mmBtu is required.

For typical cyclone coal-fired boilers, the operation of SOFA involves diverting approximately 20 percent of the secondary combustion air from the burner barrels, forcing the cyclones to operate fuel-rich. The diverted combustion air is then injected in the upper furnace, where combustion is completed.

SOFA can achieve significant NO<sub>x</sub> reduction, typically 50 to 70 percent on typical cyclone coal-fired boilers with this typical amount of air staging. A summary of several of the first OFA retrofits to cyclone-fired boilers is described in published technical papers<sup>1,2</sup>. At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998<sup>3</sup>. Additional cyclone-fired boilers have installed separated overfire air systems in conjunction with commercial fuel reburn retrofit projects<sup>4</sup>. Other NO<sub>x</sub> emission reduction demonstration projects, primarily sponsored by U.S. Department of Energy National Energy Technology Laboratory's Clean Coal Technology Program<sup>5</sup>, and other fuel reburn retrofit projects<sup>6</sup> have also installed separated overfire air on cyclone boilers. These cyclone boiler retrofit SOFA installations are listed in the U.S. NO<sub>x</sub> Reduction Projects Summary in Appendix A.3.

A cyclone-fired boiler at Ameren Electric's Sioux plant (Unit 1) reduced NO<sub>x</sub> emissions from 1.2 lb/mmBtu to as low as 0.38 lb/mmBtu in 2002 when operating with air-staged cyclones and separated overfire air, dropping NO<sub>x</sub> as much as 68% at full load (480 MW) firing a blend of 85% western subbituminous (PRB) fuel and 15% Illinois bituminous coals<sup>7</sup>. This 500 MW unit, typically firing a blend of PRB and Illinois coals, is close in unit output to LOS Unit 2. Further operation at greater amounts of overfire air and deeper cyclone air-staging in 2004 demonstrated NO<sub>x</sub> emissions down to 0.30 lb/mmBtu, a 75% reduction<sup>8</sup>. Additional testing in May-June 2005 achieved NO<sub>x</sub> emissions as low as 0.20

lb/mmBtu by “deep air-staging” the cyclones using high amounts of overfire air when firing an 80:20 PRB/Illinois coal blend at 480 MWg, an 83% reduction<sup>9</sup>.

A basic form of separated overfire air (SOFA) can be applied and installed on LOS Unit 1 and Unit 2 boilers. There are potential impacts and limitations unique to cyclone boilers firing North Dakota lignite that should be recognized as part of this emission reduction technology application.

A key aspect of successfully applying and operating separated overfire air on a cyclone-fired boiler is the ability to maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps. As secondary combustion air is diverted, less heat is released during air-staged combustion from the intentional formation of carbon monoxide, and temperatures within the cyclones decreases. The degree to which the cyclones can be operated with less than theoretical (stoichiometric) combustion air directly contributes to less NO<sub>x</sub> formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. Due to the variability of the combustible and ash components of North Dakota lignite, and the complex behavior of lignite ash when exposed to high temperatures, the ability to achieve NO<sub>x</sub> control similar to percentages demonstrated while firing bituminous or subbituminous coals with significant amounts of air-staged cyclone combustion is uncertain. Basin Electric has operated Leland Olds Station (LOS) Unit 2 with low excess air and a cyclone barrel air/fuel ratio estimated to be approximately 95% of the theoretical amount required for complete combustion, yielding a highest 24-month period average NO<sub>x</sub> emission rate during the 2000-2004 output around 0.67 lb/mmBtu while firing a high lignite/Powder River Basin (PRB) coal blend. The lignite drying systems’ vents add moisture and oxygen, raising furnace excess oxygen to appropriate levels. Using a basic SOFA system, assuming a sustainable level of NO<sub>x</sub> emissions control with the operation of modestly air-staged cyclone furnaces with suitable combustion controls, is considered feasible for LOS Unit 2.

In order to potentially achieve lower NO<sub>x</sub> emission rates with air-staged combustion for LOS Unit 2’s boiler, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite-fired cyclone boilers. “Advanced” SOFA for lignite-fired cyclone boilers offers the highest performing version of this technology, and includes relocated lignite drying system vent ports, and relocated flue gas recirculation ports.

The basic version of separated OFA for LOS Unit 2 is expected to be technically feasible to design, furnish, install, and operate. There are several challenges anticipated for implementing advanced SOFA,

primarily involving the ability to route large SOFA ductwork for diverting secondary air from the windboxes and extend the existing vent piping to new lignite drying systems' vent ports relocated from the lower to the upper furnace walls. These are believed to be solvable.

For LOS Unit 1's wall-fired boiler, basic SOFA is expected to have a modest NO<sub>x</sub> reduction of approximately 20% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.23 lb/mmBtu. For LOS Unit 2's cyclone boiler, ASOFA alone is expected to have a modest NO<sub>x</sub> reduction of approximately 28% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.48 lb/mmBtu. This estimate is based on the premise that cyclone air/fuel stoichiometric ratios will be restricted (limited to around 0.95) because of concerns for possible slag freezing, and that air-staged NO<sub>x</sub> control effectiveness will be diminished compared to demonstrated SOFA performance at other cyclone boilers.

Forms of separated overfire air described above are considered feasible as a combustion-related NO<sub>x</sub> control technique for application to LOS Station Unit 1 and Unit 2 boilers.

Another form of separated overfire air being marketed commercially is "Rotating Opposed Fired Air" (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily small to medium-sized tangentially-fired units. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NO<sub>x</sub> reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. More than three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal have been retrofitted with ROFA, each achieving a NO<sub>x</sub> reduction of approximately 53-62% from pre-installation baselines of 0.54 to 0.60 lb/mmBtu without low-NO<sub>x</sub> burners<sup>10,11,12</sup>. Even though boosted SOFA (ROFA) is not expected to produce a significant NO<sub>x</sub> control reduction advantage compared with conventional SOFA to compensate for the higher costs of supplying, installing, and operating the hot air booster fan for LOS Unit 1, it was considered technically feasible for additional NO<sub>x</sub> reduction on Unit 1 at LOS Station. For LOS Unit 1's wall-fired boiler, boosted SOFA (ROFA) is expected to reduce NO<sub>x</sub> emissions approximately 24.3% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.216 lb/mmBtu.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO<sub>x</sub> reduction performance standpoints to warrant individual consideration. This alternative was eliminated from consideration for additional NO<sub>x</sub> reduction on Unit 2 at LOS Station.

#### **A.1.2.4 Oxygen-Enhanced Combustion (OEC)**

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO<sub>x</sub> emissions resulting from “thermal NO<sub>x</sub>”, a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen component of the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO<sub>x</sub>. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal<sup>13,14</sup>. OEC was considered technically infeasible for additional NO<sub>x</sub> reduction on Unit 1 at LOS Station.

The lack of adequate experience on any cyclone-fired coal burning boiler, on a temporary demonstration or permanent full-scale basis, for a coal-fired facility of this size precludes consideration of oxygen-enhanced combustion at Leland Olds Station for the Unit 2 boiler. This is deemed to be infeasible technology at LOS for Unit 2 at the present time.

#### **A1.2.5 Flue Gas Recirculation**

Flue gas recirculation has been commonly applied to coal-fired boilers, primarily to inject flue gas into the lower furnace, just above the burners, supplied from the boiler’s economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. Flue gas recirculation for NO<sub>x</sub> control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides.

No examples of using or installing FGR on wall-fired or cyclone-fired coal-burning boilers strictly for NO<sub>x</sub> emissions control were found in available technical literature. Although FGR could be installed on LOS Unit 1's boiler, it has not been necessary for steam temperature or furnace exit gas temperature control purposes, and is not expected to reduce NO<sub>x</sub> emissions. This technology is considered technically infeasible as a stand-alone, effective NO<sub>x</sub> emissions control option for LOS Unit 1's boiler.

This technique is already practiced at Leland Olds Station in the Unit 2 boiler, primarily for operational reasons. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. For LOS Unit 2's boiler, FGR could aid in potentially providing some additional NO<sub>x</sub> emissions control if it were modified from its current configuration, as part of an advanced form of separated overfire air.

Although FGR is technically feasible for LOS Unit 2 in conjunction with other combustion improvements as part of the advanced form of SOFA, it has not been considered further as a stand-alone, effective NO<sub>x</sub> emissions control option for LOS Unit 2's boiler.

#### **A1.2.6 Water/Steam Injection (Combustion Tempering)**

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler's treated feedwater or auxiliary steam systems via a metering pump or valve. Water/steam injection has been applied and practiced on natural gas-fired utility boilers for NO<sub>x</sub> emissions control, but is believed to be relatively uncommon for continuous use on large pulverized coal utility boilers. There has been some limited testing and practice of water injection for NO<sub>x</sub> emissions control on coal-fired and natural gas-fired cyclone boilers, respectively, demonstrating up to 30% reduction at full load<sup>1,15</sup>. This technique is most effective on gas-fired or bituminous coal-fired boilers. However, no examples of using or installing water injection and continuously operating such applications strictly for NO<sub>x</sub> emissions control on wall-fired or cyclone-fired boilers burning subbituminous coal were found in available technical literature. Successful long-term operation of water injection would be difficult for lignite-fired boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion (and molten slag formation in the cyclone furnaces). For these reasons, water/steam injection is considered technically infeasible for NO<sub>x</sub> control application at Leland Olds Station.

### **A.1.2.7 Fuel Reburn**

Another combustion technology that may be applicable to control NO<sub>x</sub> emissions from the Leland Olds Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. In consideration of applying fuel reburn to LOS boilers, the existing burners/cyclones will be supplied with the majority of the fuel in the form of pulverized coal/crushed coal, respectively, and the balance of fuel is supplied to feed the reburn injection ports, such that the total heat input to each boiler is essentially the same as without fuel reburn. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO<sub>x</sub> formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO<sub>2</sub>), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO<sub>x</sub> reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone<sup>5</sup>.

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR<sup>TM</sup>).

Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Leland Olds Station plant site. Supplying enough natural gas to provide 6 to 30% of the total heat input to either or both boilers at LOS is expected to be technically

feasible, although transport pipeline installation capital costs, and current and predicted future unit natural gas costs and operating economics, are expected to be unfavorable.

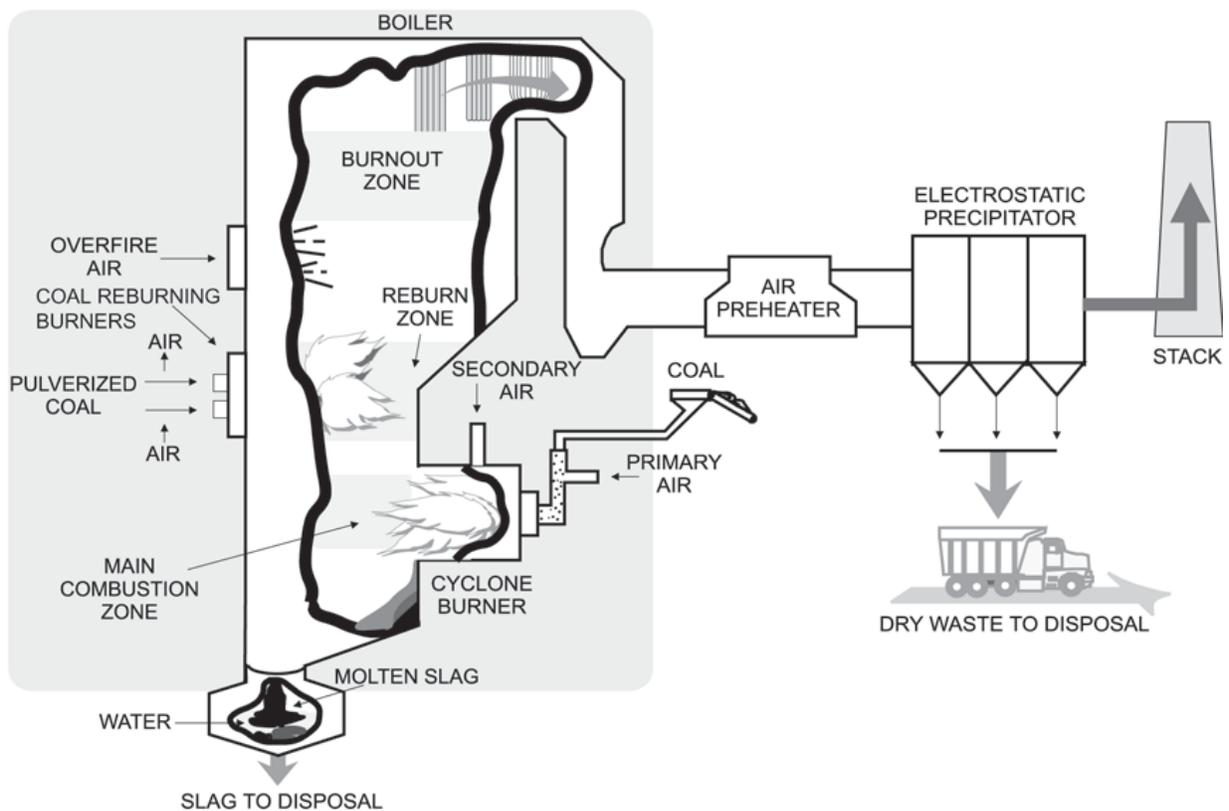
Various forms of fuel reburning have been demonstrated and operated routinely on pulverized coal and cyclone boilers for NO<sub>x</sub> emission controls<sup>1,2,4,5,6,,16,17,18,19</sup>. This technique has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO<sub>x</sub> emissions reduction has never been demonstrated on a full-scale utility boiler firing high moisture, low heat content North Dakota lignite. Pulverized and micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

#### **A.1.2.7.1 Coal Reburn**

Conventional pulverized or micronized coal reburn (PCR or mCR) have been installed and demonstrated as effective for NO<sub>x</sub> control on pulverized coal and cyclone boilers<sup>5,6,16,17,18,19</sup>. PCR/mCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of burners and upstream of SOFA, with or without air-staging the burners/cyclones. PCR/mCR will likely involve operation with fewer active pulverized coal main burners/cyclones. As a NO<sub>x</sub> control technology, PCR/mCR is considered technically feasible for application on Leland Olds Station Unit 1 boiler. Examples of PCR/mCR applied to several pulverized coal-fired boilers are included in Appendix A3. Potential application of this alternative as a NO<sub>x</sub> control option for LOS Unit 1's pulverized coal-fired boiler has similar combustion-related fuel- and air-staging, fuel preparation, and particulate emission issues as coal reburn applied to LOS Unit 2's cyclone boiler.

Pulverized or micronized coal reburn with the basic and boosted forms of separated overfire air (ROFA) can be applied and installed on Leland Olds Station Unit 1 boiler. PCR/mCR with basic SOFA is expected to reduce NO<sub>x</sub> emissions approximately 46.2% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.154 lb/mmBtu for the LOS Unit 1 boiler. PCR/mCR with boosted SOFA is expected to reduce NO<sub>x</sub> emissions approximately 48.7% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.147 lb/mmBtu for the LOS Unit 1 boiler. These expected levels of NO<sub>x</sub> reduction are considered to be a reasonable estimate, given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO<sub>x</sub> emissions control under evaluation for application to the LOS Unit 1 boiler.

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.



**Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air<sup>19</sup>**

In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO<sub>x</sub> emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state<sup>5</sup>. NO<sub>x</sub> emissions reduction efficiencies of 57 percent have been demonstrated on

cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects<sup>7,21</sup>, no known commercially-available coal reburn systems have been installed and were/are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO<sub>x</sub> emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO<sub>x</sub> emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated<sup>5,17,18</sup>. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO<sub>x</sub> reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen<sup>5,16</sup>.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO<sub>x</sub> emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce active cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Coal reburn can be applied with or without

air-staging the cyclones, i.e. operate in normal-low excess air mode or substoichiometrically. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO<sub>x</sub> reduction as part of this reburn technique will further risk slag “freezing” in the barrels and lower furnace. Reducing the number of active cyclones to maintain fuel and heat input rates comparable to normal pre-control baseline (i.e. non coal reburn) operation can accommodate reduced total cyclone coal firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems. However, if the fewer number of active cyclones are air-staged, this limits the amount of in-furnace NO<sub>x</sub> reduction that may be achieved with this technique.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to each of the LOS boilers would use two new dedicated fine-grind pulverizers and dynamic classifiers for each boiler to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the main burners/cyclones are fired with less than theoretical amounts of combustion air commonly practiced with the use of overfire air.

Particulate emissions and flue gas opacity from the stack will increase during coal reburn operation with particulate matter (PM) removal performed by an electrostatic precipitator (ESP), due primarily to higher inlet particulate loadings and smaller particle sizes of the flyash. The estimated increase in LOS Unit 2’s ESP inlet PM during coal reburn will be approximately +50% of the baseline amounts. This magnitude of flyash increase is usually not significant enough to preclude the use of reburn fuel due to exceeding permitted opacity limits, unless the ESP is already marginal on flyash removal efficiency. However, assuming that LOS Unit 2’s ESP outlet PM emissions are not allowed to increase due to the coal reburn conditions as described above, then additional PM collection equipment to increase PM collection capacity, or boiler firing restrictions, will need to be implemented. This is very significant for LOS Unit 2. Since the LOS Unit 2 boiler is fired with crushed coal, and the cyclone boiler’s typical PM emission is approximately one third to one half of the boiler’s total ash input, the existing ESPs are designed for relatively modest inlet dust loadings. There is likely to be insufficient flyash collection efficiency if coal reburn were to be applied without additional PM collection equipment to increase PM collection capacity.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO<sub>x</sub> emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during current boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Leland Olds Station Unit 2 has twelve crushers for cyclone coal grinding, each dedicated to one of the twelve cyclones. Diverting as much as 30% of the total heat input as reburn fuel could require two to four existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

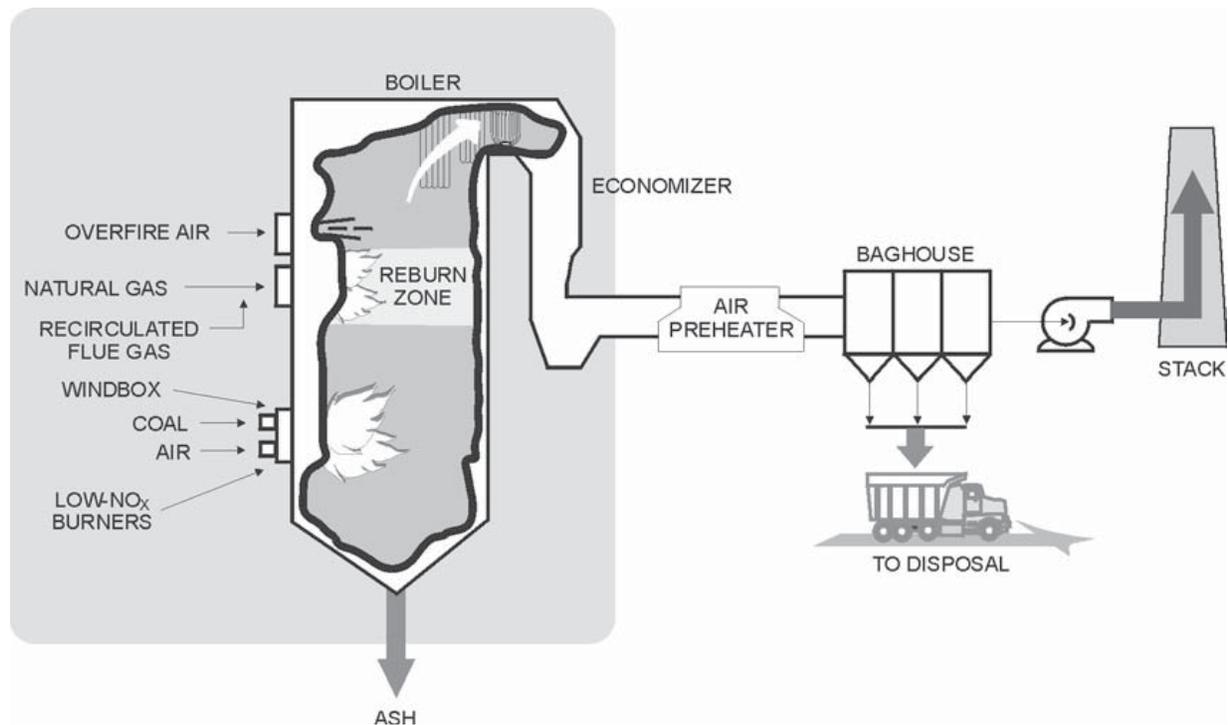
Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Leland Olds Station Unit 2 boiler. These combined techniques are expected to reduce NO<sub>x</sub> emissions approximately 52% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.32 lb/mmBtu for the LOS Unit 2 boiler. The expected level of NO<sub>x</sub> reduction is considered to be a reasonable estimate, given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO<sub>x</sub> emissions control under evaluation for application to the LOS Unit 2 boiler.

#### **A1.2.7.2 Conventional Gas Reburn**

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional gas reburn (CGR) and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

One example of CGR applied to a pulverized coal-fired boiler is included in Appendix A3. Potential application of this alternative as a NO<sub>x</sub> control option for LOS Unit 1's pulverized coal-fired boiler has similar issues as gas reburn applied to LOS Unit 2's cyclone boiler.

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.



**Figure A.1-2 Natural Gas Reburn Application on Wall-Fired Pulverized Coal Boiler with Overfire Air<sup>19</sup>**

As a NO<sub>x</sub> control technology, conventional gas reburn is considered technically feasible for application on Leland Olds Station Unit 1's boiler. Natural gas unit costs are expected to be approximately nine times more expensive per million Btu than coal. Leland Olds Station does not have a supply of large quantities of high-pressure natural gas to consume for reburn fuel. Bringing a high-pressure gas pipeline approximately 26 miles to the plant site is considered technically feasible. An order of magnitude estimated cost of \$1 Million per mile would be significant; the installed capital cost of such an asset, and the expected high unit gas prices are significant economic disadvantages, and make this alternative economically unfavorable compared to other NO<sub>x</sub> control options with similar expected performance. For these reasons, conventional gas reburn was not evaluated for consideration as an option for LOS Unit 1.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO<sub>x</sub> emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals<sup>8</sup>. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO<sub>x</sub> emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel<sup>5</sup>.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, natural gas is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO<sub>x</sub> emissions. The concerns are that the withholding of a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO<sub>x</sub> reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Leland Olds Station Unit 2's boiler. There are no published CFD model studies showing potential results of applying conventional gas reburn techniques to a North Dakota lignite-fired cyclone boiler to predict the level of NO<sub>x</sub> control that may be achievable. For lignite-fired cyclone boilers, conventional reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO<sub>x</sub> emissions than previously demonstrated elsewhere. Using high-pressure natural gas for reburn fuel is considered technically feasible for NO<sub>x</sub> emissions control applicable to Leland Olds Station's Unit 2's boiler. However, due to the expected high installed capital cost of bringing a high-pressure gas pipeline to the plant site, and high unit gas prices make this alternative economically unfavorable compared to other NO<sub>x</sub> control options with similar expected performance. CGR was not evaluated for consideration as an option for LOS Unit 2.

### **A1.2.7.3 Fuel Lean Gas Reburn**

Another approach to gas reburning is “fuel-lean gas reburn” (FLGR™) technology, which injects limited amounts of natural gas above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation.

More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company’s (WEPCO’s) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) pulverized coal boiler, FLGR™ alone was predicted to reduce NO<sub>x</sub> emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu<sup>21,23</sup>. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site. Several other examples of FLGR™ applied to pulverized coal-fired boilers are included in Appendix A3.

As a NO<sub>x</sub> control technology, FLGR™ is considered technically feasible for application of Leland Olds Station Unit 1 boiler. Potential application of this alternative as a NO<sub>x</sub> control option for LOS Unit 1’s pulverized coal-fired boiler has similar issues as conventional gas reburn. Leland Olds Station does not have a supply of large quantities of high-pressure natural gas to consume for reburn fuel. Bringing a high-pressure gas pipeline to the plant site is considered technically feasible. However, the installed capital cost of such an asset, and the expected high unit gas prices are significant economic disadvantages, and make this alternative economically unfavorable compared to other NO<sub>x</sub> control options with similar expected performance. For these reasons, fuel lean gas reburn was not evaluated for consideration as an option for LOS Unit 1.

FLGR’s first field-test on a cyclone-fired boiler was at Commonwealth Edison’s Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler<sup>20</sup>. NO<sub>x</sub> emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler’s total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO<sub>x</sub> emissions from a baseline of 0.98 lb/mmBtu<sup>21</sup>. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities’ Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler with three cyclones). This model predicted that NO<sub>x</sub> emissions could be reduced by 25-30% over that achievable from overfire air and SNCR<sup>22</sup>.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this

emission reduction technology application. As a reburn fuel, natural gas is expected to behave appropriately upon introduction in the upper furnace (above the SOFA elevation) to help reduce NO<sub>x</sub> emissions. There are concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Limited additional potential NO<sub>x</sub> reduction is anticipated when FLGR™ is operated with lignite-fired cyclones, due to the potential need to remove one or more cyclones from active firing to maintain adequate heat input in the remaining active cyclones for keeping satisfactory slag formation and flow. This creates lower furnace conditions where oxygen (cooling air from the idle cyclones) is introduced in proximity to the reburn fuel, disrupting the desired in-furnace reduction process for nitrogen oxides.

In the case of FLGR™ applied to lignite-fired cyclone boilers, the amount of fuel injected above the existing lignite drying system vent ports is expected to be substantially more than previously demonstrated in order to compensate for the higher oxygen levels due to the introduction of moist air in the lower furnace above the cyclones without relocating the vent ports. The existing lignite drying systems' vent ports' locations and introduction of oxygen to the lower furnace below the presumed FLGR™ injection points (as part of the basic form of SOFA) will likely limit the NO<sub>x</sub> emission reduction potential of the FLGR™ component.

Fuel lean gas reburn can be applied and installed on LOS Unit 2 boiler. There are no published CFD model studies showing potential results of applying fuel lean gas reburn techniques to a North Dakota lignite-fired cyclone boiler to predict the level of NO<sub>x</sub> control that may be achievable. Although this technique is considered technically feasible for application to LOS Unit 2 boiler, the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages compared to other NO<sub>x</sub> control options with similar expected performance. It was not evaluated for consideration as an option for LOS Unit 2.

Other demonstrated forms of fuel lean gas reburning, such as FLGR™ with various forms of separated overfire air, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

#### **A1.2.7.4 Fuel Oil Reburn**

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant<sup>4,5,17</sup>. NO<sub>x</sub> emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO<sub>x</sub> emissions from a baseline of 1.0 lb/mmBtu<sup>7</sup>. One example of conventional fuel oil reburn applied to a very large (800 MW) pulverized coal-fired boiler is included in Appendix A3. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to LOS Unit 1 and Unit 2's boilers. Potential application of this alternative as a NO<sub>x</sub> control option for LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler has similar issues as conventional gas reburn. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to LOS has not been performed. The expected high unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO<sub>x</sub> control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to LOS Unit 1's and Unit 2's boilers, the lack of any distinct potential NO<sub>x</sub> reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO<sub>x</sub> control cost-effectiveness analysis for Unit 1 and Unit 2 at Leland Olds Station.

#### **A1.3 Post-Combustion Controls**

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO<sub>x</sub> emissions after they have exited the boiler's lower furnace. In the case of Leland Olds Station Units 1 and 2, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic

reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation<sup>®</sup>, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the pilot-scale commercial demonstration phase of development in the utility air pollution control market is Powerspan's Electro Catalytic Oxidation<sup>®</sup>, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

### **A1.3.1 Selective Non-Catalytic Reduction (SNCR)**

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar<sup>™</sup>), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO<sub>x</sub> emission controls. While these technologies promote NO<sub>x</sub> reduction with chemical reactions that are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO<sub>x</sub> emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to fossil fuel-fired boilers with or without the use of a SOFA system. The ability to apply SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO<sub>x</sub> emissions as much as 15-40% at full load, most typically between 25-35%<sup>23,24,25</sup>.

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [CO(NH<sub>2</sub>)<sub>2</sub>] or ammonia [NH<sub>3</sub>] reacts with the nitrogen oxides [NO<sub>x</sub>], forming elemental nitrogen [N<sub>2</sub>] and water, reducing NO<sub>x</sub> emissions.

Several examples of SNCR applied to pulverized coal-fired boilers are included in Appendix A3. Long-term examples where SNCR has been used to reduce NO<sub>x</sub> emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at this cyclone-fired boiler powerplant demonstrated that SNCR can decrease NO<sub>x</sub> emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)<sup>23,24,25</sup>. These boilers, located

near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for NO<sub>x</sub> emissions control recently reported annual average emission rates around 0.55 and 0.45 lb/mmBtu, respectively.

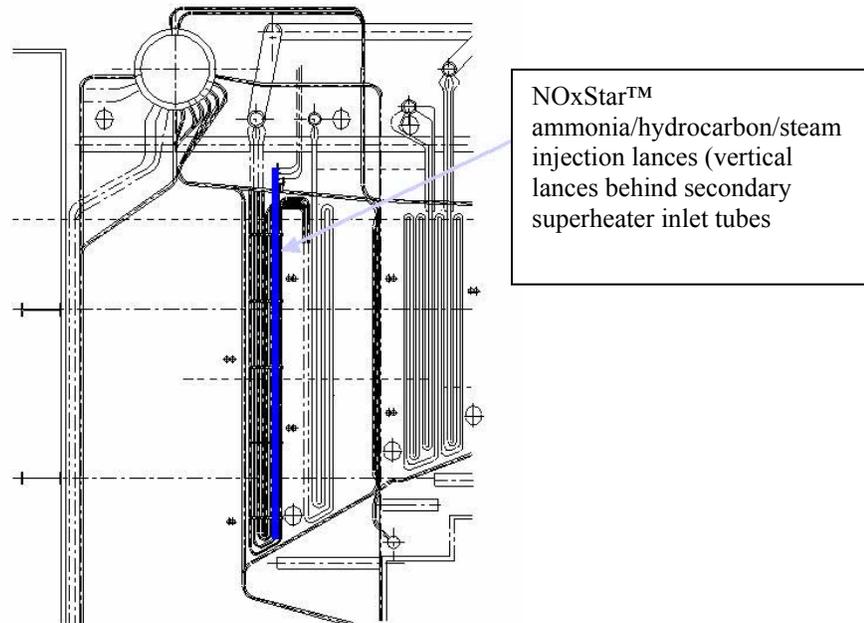
SNCR can be applied and installed on the Leland Olds Station boilers. However, with much higher installation and operation costs compared with SOFA, this alternative (without SOFA) was not evaluated for consideration as a stand-alone option for LOS Unit 1 or Unit 2.

SNCR can be installed in combination with existing close-coupled OFA, or basic or boosted forms of separated overfire air for Unit 1. The highest-performing feasible versions of conventional SNCR for LOS Unit 2 are combinations of SNCR with ASOFA with and without Rich Reagent Injection. The predicted NO<sub>x</sub> emissions for these combinations are included in the “Layered NO<sub>x</sub> Reduction Technologies” section of this report.

#### **A1.3.1.1 Hydrocarbon-enhanced SNCR (NO<sub>x</sub>Star™)**

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO<sub>x</sub>Star™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology. This involves an ammonia-based reagent that is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO<sub>x</sub> and ammonia to produce elemental nitrogen (N<sub>2</sub>) and water vapor (H<sub>2</sub>O).

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace<sup>29</sup> in Figure A.1-3.



**Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler<sup>29</sup>**

NO<sub>x</sub>Star™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002<sup>26</sup>. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal<sup>27</sup>. NO<sub>x</sub> reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations. The specific NO<sub>x</sub> reduction strictly attributable to the enhanced reagent injection without combustion effects was not disclosed.

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO<sub>x</sub> emissions. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO<sub>x</sub> reduction required. Injection nozzles are continuously purged and cooled by extracted

superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO<sub>x</sub> control performance will be reduced.

There are a number of issues related to firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR more difficult than in other coal-fired powerplants. These issues include:

- The chemical reagent injection for hydrocarbon-enhanced SNCR (NO<sub>x</sub>Star™) NO<sub>x</sub> control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO<sub>x</sub> emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO<sub>x</sub>Star™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered.
- The physical arrangement of the NO<sub>x</sub>Star™ reagent injection lances expected to be required in LOS boilers' upper furnaces will be difficult to install. Limited convection heat transfer surface is installed, resulting in high flue gas temperatures entering the air preheater so it can produce very hot combustion air for effective coal pre-drying and cyclone lignite firing. The reheater pendants or area between the reheater and primary superheater tubes are in the gas path where the temperature window is believed to be suitable for effective NO<sub>x</sub> control. The convection heat transfer surfaces in this zone are either tightly spaced or non-existent. Since the NO<sub>x</sub>Star™ reagent injection lances are permanently installed within the flue gas path, and attached to the convection heat transfer surfaces, this situation is not conducive to this type of reagent injection lance installation.
- Hydrocarbon-enhanced SNCR (NO<sub>x</sub>Star™) technology has been only applied on pulverized coal-fired boilers burning eastern bituminous fuels to date. It has not been applied to cyclone boilers, especially on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone of the LOS boilers where the reagent mixture would be injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO<sub>x</sub>Star™ lances in LOS boilers' upper furnaces is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause significant maldistribution of the NO<sub>x</sub>

reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO<sub>x</sub> emission reduction performance consistently achieved on a sustainable basis.

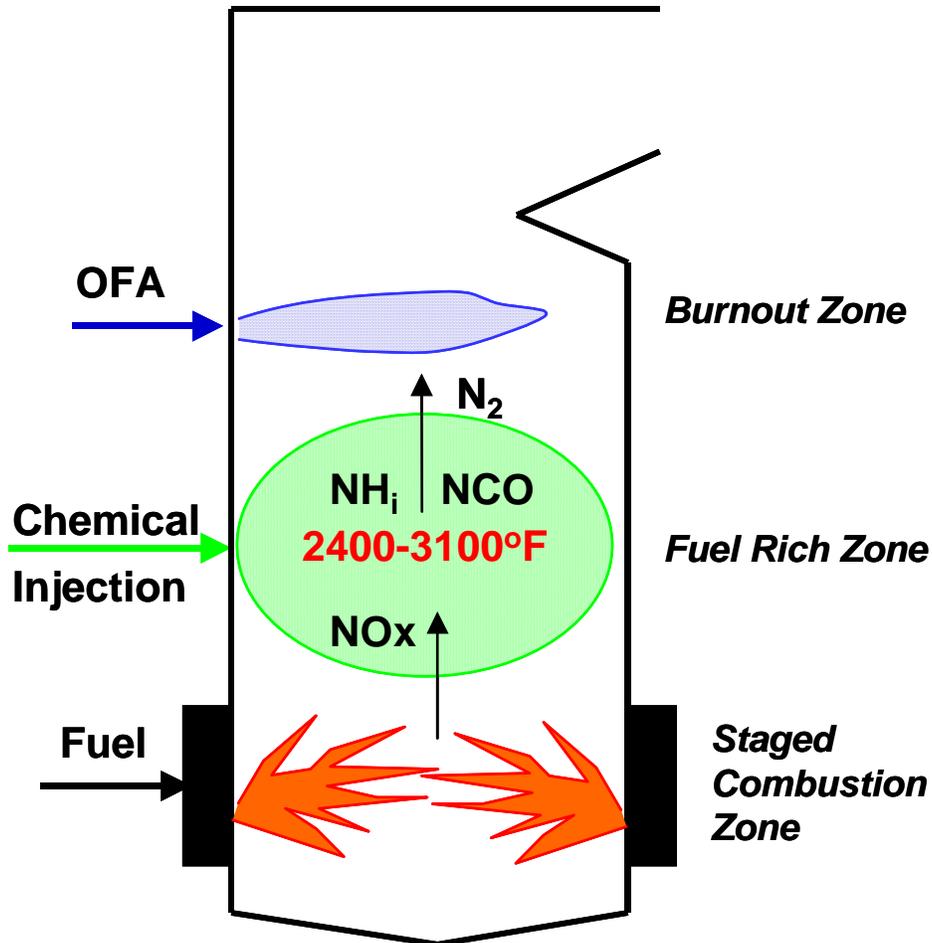
This technology is considered to be technically infeasible for application on North Dakota lignite-fired boilers. The expected difficulties for installation and susceptibility of the embedded reagent injection nozzles to rapid, severe fouling will prevent consistent performance. The specific conditions of reagent lance placement and lack of experience with this type of boiler and this high-slagging coal makes the application of hydrocarbon-enhanced SNCR technically infeasible for NO<sub>x</sub> reduction over the long term on North Dakota lignite-burning wall-fired and cyclone boilers.

#### **A1.3.1.2 Rich Reagent Injection (RRI)**

Rich Reagent Injection (RRI) is a NO<sub>x</sub> control technology that has been developed and demonstrated specifically for use on cyclone boilers. RRI is not applicable to pulverized coal-fired boilers, and therefore is technically infeasible for LOS Unit 1. Rich Reagent Injection is an SNCR process that involves the injection of urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F. The combustion gases must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which would create NO<sub>x</sub> emissions instead of reducing them.

The RRI process for NO<sub>x</sub> reduction must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The existing lignite drying system's vent ports are immediately above the top rows of cyclones. This introduces oxygen in the same vicinity as the reagent injection ports, and will disrupt the beneficial action of the fuel-rich zone and amine reagent to significantly reduce NO<sub>x</sub> emissions. Without the "advanced" version of SOFA, RRI will not contribute positively to NO<sub>x</sub> emissions control on Leland Olds Station Unit 2 boiler. This places a large emphasis on the expected performance of ASOFA in order for RRI to be successful in producing significant additional NO<sub>x</sub> emissions reduction on lignite-fired cyclone boilers.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace<sup>29</sup> in Figure A.1-4.



**Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air<sup>29</sup>**

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999<sup>25,28,29</sup>, and more recently at Ameren's Sioux Unit 1 in 2002<sup>7,8,29</sup>, and in the first half of 2005<sup>9</sup> (RRI + OFA with and without SNCR).

The NO<sub>x</sub> emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO<sub>x</sub> emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the

optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO<sub>x</sub> reduction on coal-fired cyclone boilers. Short-term parametric demonstration test data from B.L. England and Sioux show this technology can reduce NO<sub>x</sub> emissions between 10 and 36 percent<sup>7,8,9,28,29</sup>. So far, the RRI process is feasible to be used only in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system.

The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of May 2006, commercial installation of a permanent Rich Reagent Injection system has not been made on any cyclone-fired boiler. There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two boiler powerplants, this technology is considered to be commercially available for potential application on LOS Unit 2's lignite-fired cyclone boiler.

Rich Reagent Injection can potentially be applied and installed on LOS Unit 2's boiler, which must only be with an advanced form of separated overfire air (ASOFA), in combination with and without SNCR. The predicted NO<sub>x</sub> emissions for these combinations are included in the "Layered NO<sub>x</sub> Reduction Technologies" section of this report.

### **A1.3.2 Selective Catalytic Reduction (SCR)**

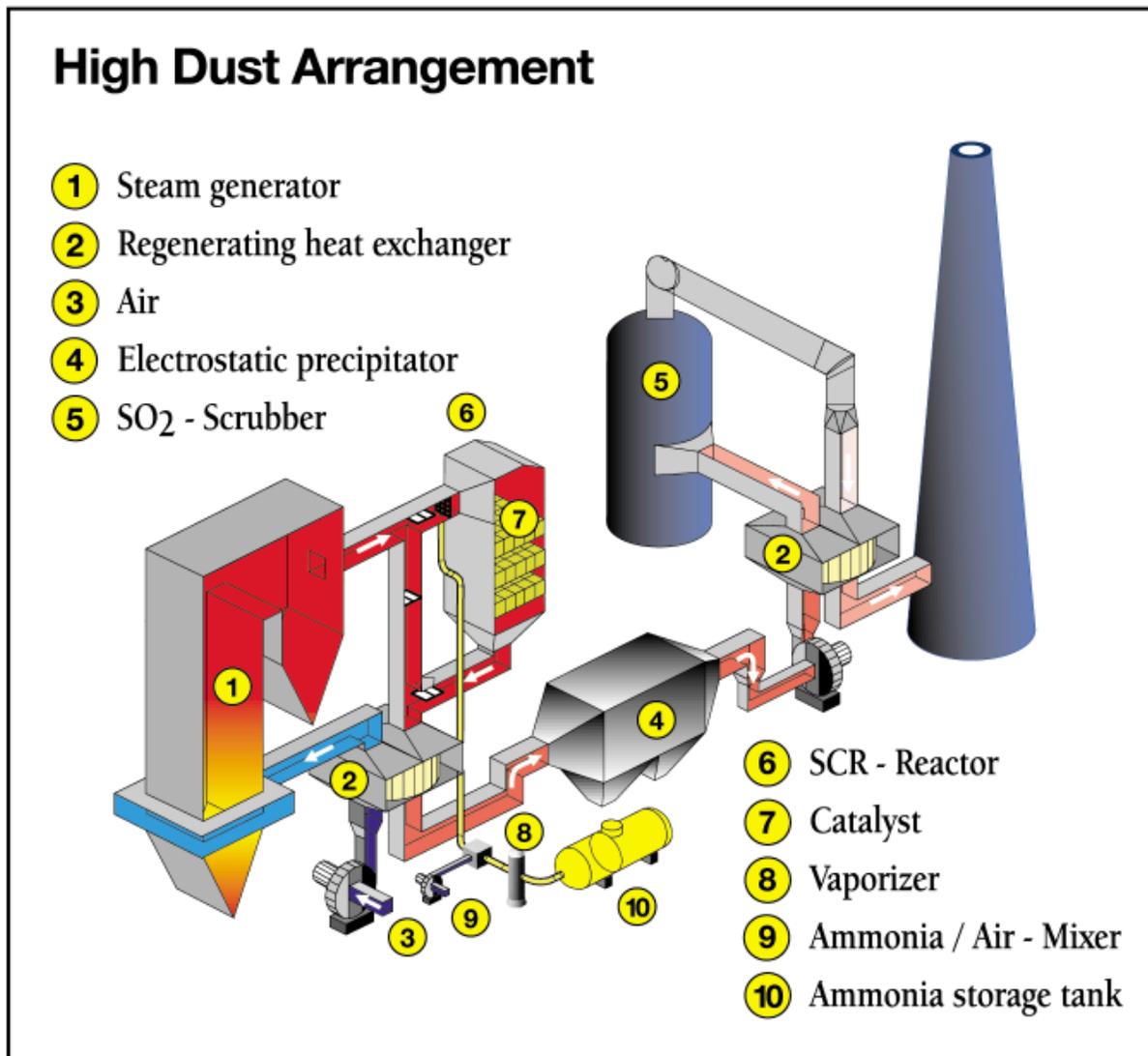
The lowest NO<sub>x</sub> emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO<sub>x</sub> to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO<sub>x</sub> rather than with the oxygen in the flue gas. A catalyst is used to enhance NO<sub>x</sub> reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO<sub>x</sub> emission reduction effect. These are described below.

### **A1.3.2.1 High-Dust Selective Catalytic Reduction (HD-SCR)**

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

**Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat**



(figure copied from Wheelabrator Air Pollution Control literature)

The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler's economizer flue gas outlet.

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited

number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota lignite. The feasibility of this alternative was evaluated for consideration as an option for LOS Unit 1 following many of the same arguments as for cyclone-fired lignite-burning boilers, as discussed below.

There are 56 BART-eligible cyclone-fired units. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the EPA's NO<sub>x</sub> SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A3 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO<sub>x</sub> emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO<sub>x</sub> emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fire boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO<sub>3</sub>:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO<sub>x</sub> emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 2 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period, and are expected to continue to operate at these low ammonia slips levels beyond the end of the initial period.
- SO<sub>3</sub>: Due to the composition of typical SCR catalysts, a small percentage of inherent SO<sub>2</sub> will be oxidized to SO<sub>3</sub>. This oxidation can be controlled by catalyst selection and can be less than 1 percent. SO<sub>2</sub> to SO<sub>3</sub> oxidation must be carefully controlled to avoid creating SO<sub>3</sub> levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO<sub>2</sub> oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ((NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>) and liquid ammonium bisulfate (NH<sub>4</sub>HSO<sub>4</sub>). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO<sub>x</sub> emissions, control ammonia slip, and minimize SO<sub>2</sub> oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when the catalyst is exposed to flue gas). Limited annual operation (i.e. ozone season only) is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis. Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increase in auxiliary power consumption increases operating cost and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
  - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO<sub>x</sub> emission reduction.
  - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 6 to 7 millimeters for plate-type catalyst, and 7 to 8 mm for honeycomb-type. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO<sub>x</sub> emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO<sub>x</sub> emission reduction and subsequent costs for reagent and catalyst replacement.

- Catalyst replacement: The frequency of catalyst replacement is influenced strongly by:
  - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution (“channeling”) through the SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.
  - Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
  - Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst.
  - Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a plate-type vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO<sub>x</sub> reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
  - Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess sodium or calcium oxide in the presence of sulfur in the flue gas can form a sodium sulfate or calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO<sub>x</sub> reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalyst. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants. The question is whether SCR is a feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional “hot-side, high-dust” configuration.

A recent article “Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals” by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine<sup>30</sup>. This paper summarized the results of SCR catalyst slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR catalyst plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial 2-month test period, and the two consecutive 2-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine ( less than 5- $\mu\text{m}$  diameter) flyash particles that enter the pores of the catalyst, react with  $\text{SO}_3$  in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.’s (EPRI’s) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study<sup>31</sup> produced field data analyzed from an “In-Situ Mini SCR Reactor” system installed in a typical “high-dust” location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed

at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites of two different catalysts' deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on North Dakota lignite-fired cyclone boilers. In order to further evaluate the feasibility of installing a conventional SCR system on North Dakota lignite-fired cyclone boilers, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash. A technical paper<sup>32</sup> was produced, from which the following technical feasibility analysis was developed. A copy of EERC's paper is included in Appendix A5. Although the source of North Dakota lignite supplied to the cyclone-fired boilers of interest in the technical paper is different than the mine supplying lignite to Leland Olds Station, it is considered similar in characteristics and suitable for comparison purposes in this feasibility analysis.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Leland Olds Station include the impacts of severe ash deposition, "popcorn ash", high temperatures, and erosion on the catalyst. For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Leland Olds Station, especially on Unit 2's boiler. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace

waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is serious enough at Leland Olds that the Unit 2 boiler must be shut down to allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the “stickiness” of the ash produced from firing North Dakota lignite. Sodium content of the LOS lignite ash averages approximately 7.6%, and can be above 9% for some of the lignite produced from the Center mine, for which the following numbers were calculated. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electric output. A cyclone boiler firing North Dakota lignite also converts as much as 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are exposed to flue gas with entrained particulate matter. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO<sub>2</sub>), and a small amount of sulfur trioxide (SO<sub>3</sub>). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO<sub>3</sub> to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO<sub>2</sub> to SO<sub>3</sub>. Excess unreacted ammonia reagent carryover (“ammonia slip”) from the SCR reactor will also react with these sulfuric acid

compounds in a similar fashion. The dominance of sodium and calcium compounds present in North Dakota lignite ash emitted from the LOS cyclone boiler will also combine with sulfur to form blinding deposits within the catalyst. The ash deposition characteristics for a cyclone-fired unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. It is anticipated that high-dust SCR performance and catalyst life for a cyclone-fired unit burning North Dakota lignite will be severely impacted. Such a high-dust SCR's catalyst life may be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to gas-side fouling. Tubular air pre heaters typically supplied with cyclone boilers tolerate moderate dust loadings and gas-side fouling, since their height and size make them difficult to maintain gas-side cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. It is expected that a high-dust SCR installation on a cyclone-fired unit burning North Dakota lignite will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. There is concern that carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst in a high-dust, hot-side installation on a cyclone-fired unit burning North Dakota lignite. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which can concentrate the amount of  $\text{NO}_x$  passing through unrestricted areas with insufficient reagent, thus producing ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is gas temperature. The performance of any SCR catalyst is highly dependent on the flue gas temperature. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly-supplied catalyst suitable for a high-dust SCR reactor at temperatures above 800°F results in severe and rapid deterioration of the catalyst and SCR reactor's NO<sub>x</sub> emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

North Dakota lignite-fired cyclone boilers, including those at Leland Olds Station, have limited gas-path economizer surface and high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlet in Leland Olds Unit 2 can be significantly higher than 750°F.

High gas temperatures at the air heater inlet of North Dakota lignite-fired cyclone boilers are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Leland Olds unit to operate with the lower economizer outlet flue gas temperatures.

Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 800°F) that exist between the convection pass economizer and air heater on the Leland Olds Station Unit 2's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota

lignite has a modest to high ash content. Lignite supplied from the Center mine, for which the following numbers were calculated, has an average annual fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. Severe ash depositions can cause distortions in gas distribution (“channeling”) through the SCR reactor, which will aggravate erosion in the high velocity areas and create conditions leading to ineffective performance of the catalyst. In addition, effective on-line cleaning of the high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst in a high-dust SCR installation for a cyclone boiler firing North Dakota lignite may need to be more frequent than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite. Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA’s BART Guideline states that for a technology to be feasible it must be “available and applicable”. SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is “applicable” for a cyclone-fired unit burning North Dakota lignite.

In accordance with EPA’s BART Guideline, a “commercially available control option will be presumed applicable if it has been used on the same or similar source type” [70 CFR 39165]. Hot-side, high-dust SCR technology has been retrofitted on existing coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA's BART Guideline also states a technology identified as technically infeasible, "[the States] should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit" [70 CFR 39165]. Such a demonstration of technical infeasibility "involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)"[70 CFR 39165]. In this SCR technology application, it appears that a cyclone-fired utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on such a fuel source. The risk of failure and uncertainty of successfully applying high-dust, hot-side SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appears substantial.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the pulverized coal-fired Unit 1 boiler and the cyclone-fired boiler on Unit 2 at Leland Olds Station.

#### **A1.3.2.2 Low-Dust Selective Catalytic Reduction (LD-SCR)**

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NO<sub>x</sub> emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in the U.S. NO<sub>x</sub> Control Project Summary listing in Appendix A. If applied to LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO<sub>x</sub> emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through new ductwork leading to a supplemental heat addition section ahead of an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added upstream of the LD-SCR reactor can be supplied from high pressure/temperature steam coils (indirect heat exchange) or directly from fossil fuel (natural gas, fuel oil, or propane)-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO<sub>x</sub>- ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be a small amount of leakage between the untreated and treated gas streams such that the exit flue gas has higher NO<sub>x</sub> concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO<sub>x</sub> emissions, which will add to the amount from the boiler input into the LD SCR reactor. The GTG-HE outlet flue gas temperature on the downstream side of the LD SCR has to be higher than the inlet gas temperature.

The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for Leland Olds Station's pulverized coal-fired Unit 1 boiler and Unit 2's cyclone-fired boiler with existing particulate collection via electrostatic precipitators are as follows:

- **Catalyst Fouling and Deactivation:** An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, there is concern that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor could cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5- $\mu$ m diameter) flyash

particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust or low-dust/tail-gas SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO<sub>3</sub> in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of sodium or calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor has stated it is their “experience that low-dust catalyst is more difficult to clean than that from high-dust”<sup>33</sup>. Ash deposition characteristics for a cyclone-fired unit burning North Dakota lignite will create difficult-to-remove ash deposits and blinding of conventional catalyst. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.

Deposits on the gas-to-gas heat exchanger ahead of the low-dust SCR reactor will decrease heat transfer between the incoming (warm) flue gas and the outgoing (warmer) flue gas and be increasingly difficult to successfully remove over time. Low flue gas temperatures are inadequate to promote the effective activity of the catalyst in reducing NO<sub>x</sub> emissions. Thus, increased consumption of supplemental heat, preferably in the form of propane or natural gas, will be required to raise the temperature of the flue gas ahead of the LD-SCR reactor. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the rotary regenerative-type GTG HE cleaning cycle becoming reentrained in the reheated flue gas. This can lead to further accumulation of deposits at the inlet and within the catalysts layers of the TG-SCR reactor, creating a vicious cycle of diminishing performance.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment are numerous. The lack of pertinent experience with all aspects of design, construction, operation, and maintenance of low-dust SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the LD-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, cold-side SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

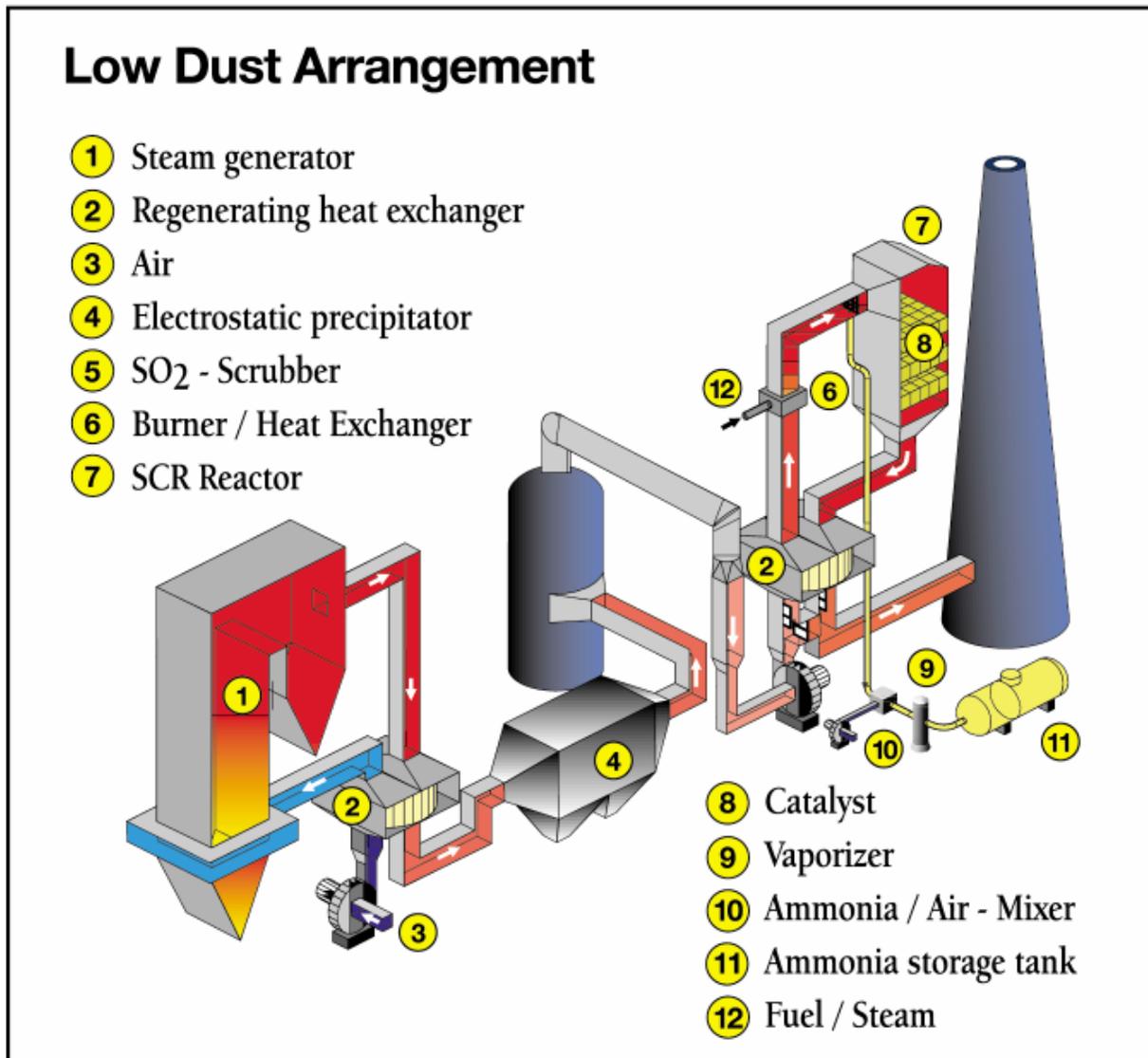
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit with a cyclone-fired boiler, this control option is considered technically infeasible for Leland Olds Station's pulverized coal-fired Unit 1 boiler and the cyclone-fired boiler of Unit 2.

### **A1.3.2.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)**

A tail-gas (TG) SCR is a low-dust SCR system where the SCR reactor is installed on the cold side of the air preheater downstream of a FGD scrubber. The FGD outlet flue gas passes through a low-dust gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. After the LD GTG-HE, the flue gas will travel through new ductwork leading to a supplemental heat addition section ahead of an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This retrofit normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from fossil fuel-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the NO<sub>x</sub> – ammonia reaction in the presence of the TG SCR catalyst to be effective. The gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be a small amount of leakage between the untreated and treated gas streams. With a positive flue gas pressure FGD system

upstream, the leakage will be such that the GTG-HE outlet exit (stack inlet) flue gas has a higher NO<sub>x</sub> concentration than the TG SCR reactor outlet gas. The direct-fired flue gas reheat duct burners will also create NO<sub>x</sub> emissions, which will add to the amount from the boiler input into the TG SCR reactor. The GTG-HE outlet flue gas temperature on the downstream side of the TG SCR going to the stack will be significantly lower than would occur in a conventional high-dust, hot-side SCR or low-dust, cold-side SCR application.

There is no experience with low-dust/tail-gas SCR technology on eastern bituminous, western subbituminous coal or lignite-fired SEGUs requiring full flue gas reheat prior to the reactor inlet in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO<sub>x</sub> emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)<sup>34</sup>.

Leland Olds Station Unit 1 and Unit 2 boilers do not currently incorporate any flue gas desulfurization equipment, which without such FGD would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. Both Unit 1's boiler and Unit 2's boiler will have new FGD systems to implement future BART sulfur control requirements associated with the North Dakota State Implementation Plan (SIP).

The factors that make tail-gas SCR technology infeasible for the pulverized coal-fired Unit 1 boiler and the cyclone-fired Leland Olds Station Unit 2 boiler with existing particulate collection via electrostatic precipitators are as follows:

- The TG SCR reactor downstream of a FGD scrubber will still be exposed to flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds passing through and carried-over from a wet FGD scrubber. The treated gas stream will carry sodium sulfate solids, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. There is serious concern that these fine particles will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO<sub>x</sub> removal is based.

- Deposits on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas and be increasingly difficult to successfully remove over time. Low flue gas temperatures are inadequate to promote the effective activity of the catalyst in reducing NO<sub>x</sub> emissions. Thus, increased consumption of supplemental heat, preferably in the form of propane or natural gas, will be required to raise the temperature of the flue gas ahead of the TG-SCR reactor. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the TG SCR reactor could still suffer catalyst fouling from the deposits dislodged from the rotary regenerative-type GTG HE cleaning cycle becoming reentrained in the reheated flue gas. This can lead to further accumulation of deposits at the inlet and within the catalysts layers of the TG-SCR reactor, creating a vicious cycle of diminishing performance.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a pulverized coal-fired boiler and the cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Leland Olds Station pulverized coal-fired Unit 1 boiler and the cyclone-fired Unit 2 boiler.

### **A1.3.3 Electro-Catalytic Oxidation (ECO<sup>®</sup>)**

Powerspan's Electro-Catalytic Oxidation (ECO<sup>®</sup>) system is a multi-pollutant technology designed to control emissions of NO<sub>x</sub>, SO<sub>2</sub>, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO<sup>®</sup> process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO<sub>x</sub>, and other constituents in the flue gas stream. The flue gas stream

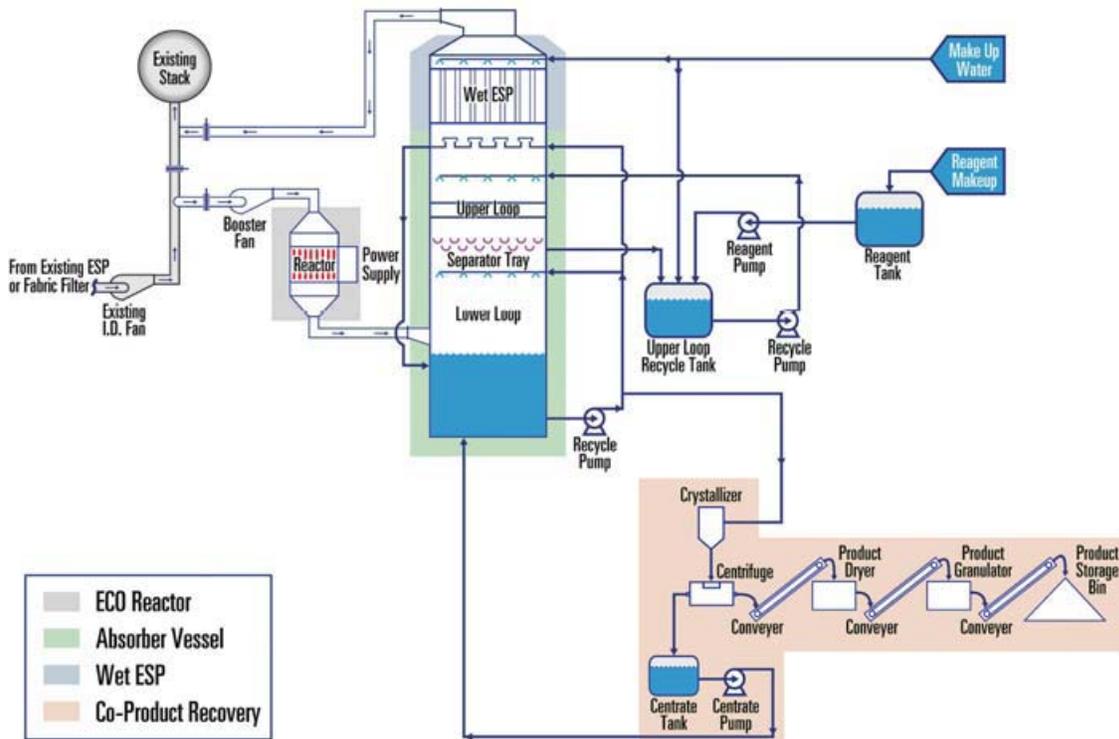
then enters the bottom of the ECO<sup>®</sup> scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO<sub>3</sub>), sulfuric acid (H<sub>2</sub>SO<sub>4</sub>), nitric acid (HNO<sub>3</sub>)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO<sub>2</sub>, NO<sub>2</sub>, acid gasses and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO<sup>®</sup> process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury.

An updated schematic process flow diagram for the basic ECO<sup>®</sup> process is shown in Figure A.1-7.

**Figure A.1-7 – Electro-Catalytic Oxidation (ECO<sup>®</sup>) Process Flow Diagram**

(copied from <http://www.epa.gov/appcdwww/apfb/EPA600R03110.pdf>)

## ECO<sup>®</sup> Process Flow



Powerspan has been involved in an extended ECO<sup>®</sup> process demonstration using a 28 MW equivalent “slipstream” Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO<sup>®</sup> CDU

project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO<sub>x</sub> removal is stated to be up to 90% with a claimed 0.05 lb NO<sub>x</sub>/mmBtu outlet condition achievable for the front-end of the ECO<sup>®</sup> process. Further sustained operational tests of the ECO<sup>®</sup> CDU were performed during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO<sup>®</sup>) process can be potentially applied to in order to reduce NO<sub>x</sub> emissions. The effectiveness of this ECO<sup>®</sup> process for NO<sub>x</sub> control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO<sub>x</sub> concentration around 0.5 lb/mmBtu. This would result in a stack NO<sub>x</sub> emission around 0.05 lb/mmBtu.

As of May, 2006, the ECO<sup>®</sup> process has not been demonstrated in a full-scale (or less-than full-scale) configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from any coal-fired cyclone boiler. According the EPA's BART Guideline, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" [70 CFR 39164].

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO<sup>®</sup> process technically infeasible for Unit 1's pulverized coal-fired boiler and the LOS Unit 2 cyclone boiler. These issues include:

- **Deposits and Pluggage:** The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO<sup>®</sup> process, and thus could have a serious impact on Leland Olds Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging

index precludes the use of the ECO<sup>®</sup> process as technically feasible for BART as applied to a boiler firing North Dakota lignite.

- Reliability and Availability: Leland Olds Station's major planned outages for each unit are scheduled to occur once every three years. Any NO<sub>x</sub> control technology selected as BART will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO<sup>®</sup> system is a new technology and is not as highly developed as other more common NO<sub>x</sub> and SO<sub>2</sub> control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO<sup>®</sup> CDU are acceptable to meet the expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO<sup>®</sup> process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO<sup>®</sup> downstream ammonia scrubber's coproduct crystallization and granulation equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO<sub>2</sub> scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at LOS, considerable costs would be incurred for interim storage and shipment of the ECO<sup>®</sup> process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.
- Size of the barrier reactor: Powerspan recently indicated that they would scale the barrier reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for LOS Unit 1's pulverized coal-fired boiler and Unit 2 cyclone boiler's maximum flue gas flow and gas stream

constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork could be limited for potential retrofit to LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone boiler. Site space constraints are considered to be a detriment to technical feasibility for potential application of the ECO<sup>®</sup> process at Leland Olds Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO<sup>™</sup> system, require an increase in station auxiliary power consumption. For NO<sub>x</sub> control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the lack of full-time, full-scale experience, especially on such high fouling coals as North Dakota lignite, and other operational issues, the ECO<sup>®</sup> system was considered technically infeasible as a BART alternative for Leland Olds Station for Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler.

#### **A1.4 "Layered" NO<sub>x</sub> Reduction Technologies**

Many of the NO<sub>x</sub> emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO<sub>x</sub> emissions prior to a boiler's flue gas exit. However, all the possible NO<sub>x</sub> control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by firing lignite coal.

##### **A1.4.1 SOFA Combined With Other NO<sub>x</sub> Reduction Technologies**

Separated Overfire Air (SOFA) can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO<sub>x</sub> emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace.

#### **A1.4.1.1 SOFA with SNCR**

Selective non catalytic reduction technologies are post-combustion, in-furnace NO<sub>x</sub> control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the mass rate of NO<sub>x</sub> will be lower, thus allowing the amount of chemical reagent consumption to be minimized in order to achieve the targeted NO<sub>x</sub> emission rate from the boiler outlet.

Several examples of SNCR technology applied to pulverized coal-fired boilers are included in Appendix A3. As a NO<sub>x</sub> control technology, SNCR with close-coupled OFA, or basic or boosted SOFA is considered technically feasible for application on Leland Olds Station Unit 1's boiler. SNCR with close-coupled OFA is expected to reduce NO<sub>x</sub> emissions approximately 24.5% below 2000-2004 pre-control highest 24-month average NO<sub>x</sub> baseline levels for the LOS Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. SNCR with basic separated OFA is expected to reduce NO<sub>x</sub> emissions approximately 42% below 2000-2004 pre-control highest 24-month average NO<sub>x</sub> baseline levels. The highest performing basic SNCR system combined with the boosted form of SOFA (ROFA) on LOS Unit 1's boiler is potentially able to achieve NO<sub>x</sub> emission rates of 0.157 lb/mmBtu, an overall reduction of 45.1% below 2000-2004 pre-control highest 24-month average NO<sub>x</sub> baseline levels during operation at full load.

Tests on the cyclone boilers at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO<sub>x</sub> emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO<sub>x</sub> emission reduction of 72% from pre-retrofit baseline<sup>23,24</sup>.

SNCR with either the basic or the advanced forms of separated overfire air (ASOFA) can be applied and installed on LOS Unit 2's boiler. Air-staging the Unit 2 cyclones with the use of separated overfire air to further complement combustion NO<sub>x</sub> reduction is an optional part of this technique. However, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO<sub>x</sub> emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR with ASOFA is expected to reduce NO<sub>x</sub> emissions approximately 38% below NO<sub>x</sub> levels predicted for ASOFA operation, and potentially 54.5% overall from 2000-2004 pre-control highest 24-month average baseline levels for the LOS Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is

potentially able to achieve NO<sub>x</sub> emission rates of 0.304 lb/mmBtu, respectively, when combined with the advanced form of SOFA on LOS Unit 2 boiler during operation at the pre-controlled baseline load. This expected level of sustained NO<sub>x</sub> reduction is considered to be a reasonable estimate, given the concerns expressed about the potential limits of separated overfire air techniques to achieve typical NO<sub>x</sub> reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as “Rotating Mixing” (Rotamix). In the United States’ utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NO<sub>x</sub> reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO<sub>x</sub> reduction of approximately 0-55% beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO<sub>x</sub> burners<sup>10,11,12</sup>.

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO<sub>x</sub> reduction performance standpoints to warrant individual consideration for Leland Olds Station boilers. It was not evaluated for consideration as an option for LOS Unit 1 or Unit 2 boilers.

#### **A1.4.1.2 SOFA with RRI**

As previously stated, Rich Reagent Injection is not applicable to pulverized coal-fired boilers, and therefore is technically infeasible for LOS Unit 1. RRI must be combined with an advanced form of separated overfire air, and can be installed and operated with and without SNCR, for coal-fired cyclone boilers. RRI must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen

oxide emissions. This requires air-staged cyclones and separated overfire air operation. For lignite-fired cyclone boilers, the basic form of separated overfire air is incompatible with RRI, and is expected to be much less effective in reducing NO<sub>x</sub> emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reagent will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture-laden airstream will disrupt the desired in-furnace nitrogen oxides reduction process.

Demonstration of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR approximately 1.0, NO<sub>x</sub> emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, and an additional 15% NO<sub>x</sub> reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip<sup>7</sup>. Testing RRI with SOFA in 2002 at an average cyclone air-to-fuel stoichiometric ratio (S.R.) of 0.95 resulted in NO<sub>x</sub> reductions as much as 29% for RRI (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline<sup>7</sup>. Tested NO<sub>x</sub> emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs/ NH<sub>3</sub> per lb NO<sub>x</sub>)<sup>7</sup>. In 2004, further operation of the SOFA system at lower cyclone stoichiometric ratios (S.R. of 0.90) resulted in reducing NO<sub>x</sub> emissions down to 0.3 lb/mmBtu with approximately 26% overfire air flow without RRI<sup>8</sup>. Parametric testing in May 2005 reduced NO<sub>x</sub> emissions between 15-38% with RRI+SOFA, down to 0.15 to 0.20 lb/mmBtu with reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output<sup>9</sup>.

It should be recognized that these demonstration tests of RRI were very limited in duration, with a particular combination of active cyclones, boiler output, active injector patterns, reagent concentration and mass flow rate, injection velocity, dispersion angle, and droplet size being established for a few hours over the course of a few days or weeks. Thus, the stated results do not reflect long-term NO<sub>x</sub> control performance, reagent usage, or ammonia slip levels.

For LOS's Unit 2 lignite-fired cyclone boiler, RRI with ASOFA is potentially able to be installed and operate. This option is assumed to provide a modest NO<sub>x</sub> reduction of approximately 43% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.38 lb/mmBtu, for Unit 2's boiler, with less than 1 ppm ammonia slip. This is approximately 22% lower than the level produced by

ASOFA alone. This estimate is based on the premise that cyclone air/fuel stoichiometric ratios will be restricted (limited to around 0.95) because of concerns about possible slag freezing, and that reagent effectiveness will be diminished compared to demonstrated performance at B.L England Station Unit 1 and Sioux Unit 1 boilers. This option was not included in the cost-effectiveness analysis due to estimated lower NO<sub>x</sub> reduction and higher reagent consumption versus SNCR with ASOFA.

#### **A1.4.1.3 SOFA with RRI and SNCR**

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO<sub>x</sub> emissions reduction at Conectiv's B.L. England Unit 1 boiler firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu<sup>30</sup>. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal Sioux Unit 1 reportedly demonstrated NO<sub>x</sub> emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, for an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications. A technical paper by REI was presented at a late 2005 conference documenting these findings<sup>11</sup>.

As with RRI with ASOFA, demonstration tests of RRI and SNCR with ASOFA were very limited in duration. Thus, the stated results do not reflect long-term sustained NO<sub>x</sub> control performance, reagent usage, or ammonia slip levels.

For LOS's Unit 2 lignite-fired cyclone boiler, RRI and SNCR with ASOFA is potentially able to be installed and operate. This combination was assumed to be capable of achieving an overall NO<sub>x</sub> reduction of approximately 60% below a baseline level, down to 0.265 lb/mmBtu, for Unit 2's boiler, with ammonia slip limited to 5 ppmvd. This is a reduction approximately 46% beyond the level produced by ASOFA alone, with the SNCR contribution approximately 30% below RRI+ASOFA. As previously discussed, this level of NO<sub>x</sub> emissions reduction is considered to be a reasonable estimate, given the concerns expressed about the ability of RRI to be effective due to potential limits of separated overfire air techniques when applied to lignite-fired cyclone boilers.

#### **A1.4.1.4 SOFA with Reburn**

Most, if not all, of the recent conventional fuel reburn installations include separated OFA. Coal reburn and conventional gas reburn (CGR) are combined with SOFA. Several of these examples were already described<sup>4,5,6,7,8, 18,19,20,21</sup>.

For the most effective NO<sub>x</sub> reduction performance by applying the various available forms of fuel reburn, the injection of gaseous fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases generated from staged burners below the fuel reburn injection location. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures.

For lignite-fired cyclone boilers, conventional reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO<sub>x</sub> emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will oxidize the reburn fuel and significantly disrupt the desired in-furnace reduction process for nitrogen oxides.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA in combination with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared to SOFA with air-staged cyclones without reburning. This is significant, especially for alternatives with coal reburn to allow the solid fuel introduced below the SOFA ports to burn completely prior to the furnace exit plane. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO<sub>x</sub> reduction process to occur.

Fuel-lean gas reburn (FLGR<sup>TM</sup>) can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. More commonly, FLGR<sup>TM</sup> has been installed with SNCR for NO<sub>x</sub> emission reduction<sup>22,23,24,25</sup>. A potential advantage of FLGR<sup>TM</sup> over conventional gas reburn is that the former involves less reburn fuel consumption. As discussed below, FLGR<sup>TM</sup> alone or in combination with basic SOFA (without ASOFA) is expected to be ineffective on lignite-fired cyclone boilers.

As a NO<sub>x</sub> control technology, FLGR™ with SOFA is considered technically feasible for application on Leland Olds Station Unit 1 boiler. However, because of the lack of apparent NO<sub>x</sub> control performance advantage over other similar or better performing control alternatives, high operating cost and significant capital costs for supplying natural gas, this alternative was not evaluated for consideration as an option for LOS Unit 1. More commonly, FLGR™ has been installed with SNCR for NO<sub>x</sub> emission reduction<sup>22,23,24,25</sup>. This is discussed in a subsequent section involving amine-enhanced FLGR™.

In the case of FLGR™ applied to lignite-fired cyclone boilers, air-staging the cyclones with the use of separated overfire air to further complement combustion NO<sub>x</sub> reduction is an optional part of this reburn technique which will further risk slag “freezing” in the barrels and lower furnace. The amount of fuel injected above the existing lignite drying system vent ports (which will not be relocated as part of the basic form of SOFA) is expected to be substantially more than previously demonstrated in order to compensate for the higher oxygen levels due to the introduction of moist air in the lower furnace above the cyclones without relocating the vent ports. The existing lignite drying systems’ vent ports’ locations and introduction of oxygen to the lower furnace below the presumed FLGR™ injection points will likely limit the NO<sub>x</sub> emission reduction potential of the FLGR™ component. Limited additional potential NO<sub>x</sub> reduction is anticipated when FLGR™ is operated with lignite-fired cyclones, due to the potential need to remove one or more cyclones from active firing to maintain adequate heat input in the remaining active cyclones for keeping satisfactory slag formation and flow. Reducing the number of active cyclones, which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air, is the typical approach to avoid slag tapping problems. This creates lower furnace conditions where oxygen (cooling air from the idle cyclones) is introduced in proximity to the reburn fuel, disrupting the desired in-furnace reduction process for nitrogen oxides.

FLGR™ technology with basic and advanced forms of SOFA was not included in the cost-effectiveness analysis for LOS Unit 2, because of the lack of apparent NO<sub>x</sub> control performance advantage over other similar or better performing control alternatives, high operating cost and significant capital costs for supplying natural gas.

#### **A1.4.2 SNCR and Reburn**

Various forms of SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO<sub>x</sub> emissions prior to the boiler’s flue gas exit. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one

vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems<sup>18</sup> as “advanced” gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature or vendor experience lists. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO<sub>x</sub> emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from pre-control baseline<sup>6,35</sup>.

As a combination of NO<sub>x</sub> control technologies, conventional gas reburn with SNCR and SOFA may be capable of being installed on the Leland Olds Station Unit 1 boiler. However, because of the lack of any permanent commercial gas reburn experience applying this combination of technologies to wall-fired coal-burning boilers, and apparent negative economic advantage due to high operating cost and significant capital costs for supplying natural gas versus the expected slight potential gain in NO<sub>x</sub> control performance, CGR with ASOFA and SNCR alternative was not evaluated for consideration as an option for LOS Unit 1.

No example of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers was found in available technical literature. As previously expressed with layered technologies involving conventional reburn, an “advanced” form of SOFA is desired for lignite-fired cyclone boilers. The lack of experience with this combination on a cyclone-fired boiler, especially for lignite-firing, makes the prediction of success and the level of NO<sub>x</sub> emission reduction potential uncertain. CGR with ASOFA and SNCR was considered technically infeasible as an option for LOS Unit 2.

Rich Reagent Injection has not been demonstrated of being capable of combining with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in available technical literature or vendor experience lists. This combination of technologies is considered technically infeasible as an option for LOS Unit 2.

Because of the lack of any permanent commercial coal reburn experience applying this combination of technologies to pulverized coal-fired or cyclone-fired boilers, apparent negative economic advantage due to high operating cost and significant capital costs for preparing the reburn fuel versus the expected slight potential gain in NO<sub>x</sub> control performance, PCR/mCR with ASOFA and SNCR alternative was not evaluated for consideration as an option for LOS Unit 1's and Unt 2's boilers. This combination of technologies is considered technically infeasible as an option for LOS Unit 1's and Unt 2's boilers.

#### **A1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR**

Fuel-lean gas reburn has been combined with SNCR on at least five pulverized coal-fired utility powerplants retrofit installations within the United States<sup>23</sup>. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR, or SNCR only (without SOFA) for the specific level of control desired or required. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO<sub>x</sub> emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details<sup>36</sup>.

As a combination of NO<sub>x</sub> control technologies, FLGR™ with SNCR (with or without SOFA) is considered technically feasible for application of Leland Olds Station Unit 1 boiler. However, with disadvantages of high operating cost and significant capital costs for supplying natural gas compared to other similar or better performing control alternatives, this alternative was not evaluated for consideration as an option for LOS Unit 1.

No example of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler was found in available technical literature or vendor experience lists. It may be possible to be applied on a cyclone-fired boiler burning lignite, but the amount of NO<sub>x</sub> control performance contribution from the FLGR™ system is expected to be limited.

Because a FLGR™ + SNCR (AEFLGR™) system (without basic or advanced versions of SOFA) lacks demonstrated and commercial experience in this application, particularly on a cyclone-fired boiler burning lignite, this combination is considered infeasible as an option for LOS Unit 2.

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## **A2 Cost of Compliance for NO<sub>x</sub> Controls - Estimate Details**

An evaluation was performed to determine the compliance costs of installing various feasible NO<sub>x</sub> control alternatives on Leland Olds Station boilers. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into sustained annual commercial operation the particular control technology. The results of this evaluation are summarized in the main report, Tables 2.4-1 through 2.4-7 for LOS Unit 1, and Tables 2.5- through 2.5-9 for LOS Unit 2.

### **A2.1 Capital Cost Estimates for NO<sub>x</sub> Controls**

The capital costs to implement the various NO<sub>x</sub> control technologies were largely estimated from unit output capital cost factors (\$/kW) published in technical papers discussing those control technologies. In the cases with SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. The capital costs for combinations of NO<sub>x</sub> reduction technologies evaluated were typically estimated based upon simple arithmetic addition of the individual unit output capital cost factors for these technologies, multiplied by the nameplate capacity ratings of the steam-electric generating units at Leland Olds Station. These cost estimates were adjusted for inflation where appropriate (to 2005\$), and are considered to be study grade, which is + or – 30% accuracy, or better.

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are subject to:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner's final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO<sub>x</sub> control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural,

upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.

- Size influences – some technologies’ capital costs are more sensitive to “economies of scale” than others.
- Capacity margins – some technologies’ may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies’ have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.
- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule demands for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated installed capital cost for each alternative evaluated was multiplied by the capital levelization factor (0.08718) to yield levelized total annualized capital cost.

## **A2.1.1 Combustion Controls’ Capital Cost Estimates**

### **A2.1.1.1 Separated Overfire Air Capital Cost Estimates**

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on LOS wall-fired and cyclone boilers includes ports across the front and rear walls of the upper furnace.

The unit capital cost factor is expected to be at the low end of the typical range<sup>37</sup> for LOS Unit 1: \$6.3/kW or \$1.4M; and near the high end of the same range for LOS Unit 2: \$12.5/kW or \$5.5M.

A basic form of SOFA for potential retrofit on LOS Unit 1's boiler will include providing new (or relocating the existing close-coupled) overfire air ports and waterwall tube openings adjacent and above the top row burners in the middle furnace to a slightly higher elevation across the front and rear walls. This requires extension of the existing CCOFA windbox or creation of a new SOFA windbox to supply the new ports. This retrofit will also close-off the existing CCOFA ports.

A boosted form of SOFA (ROFA) for potential retrofit on LOS Unit 1's boiler will include additional secondary air ductwork to and from a new hot air booster fan. This is expected to cost in the area of +\$14.4/kW or approximately \$3.1M for Unit 1's additional capital cost over and above the basic SOFA system. Overall, the boosted version of SOFA is estimated to have an installed capital cost of approximately \$20.7/kW or \$4.5M for LOS Unit 1. The installed capital cost estimate for LOS Unit 1's boosted SOFA (ROFA) alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the unit capital cost factor for ROFA of \$20/kW ( $\times 1.035 = \$20.7/\text{kW}$ ) included in a WRAP (Western Regional Air Partnership) draft report<sup>38</sup> published on their website, dated April 26, 2005. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

For LOS Unit 2, an advanced form of SOFA unique to North Dakota lignite-fired cyclone boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the lignite drying systems' vent piping to supply the new ports. This is expected to cost in the area of +\$5/kW or approximately \$2.1M for Unit 2's additional capital cost over and above the basic SOFA system. This retrofit will also close-off the existing FGR ports, currently coinciding with the existing pre-dry vent ports on Unit 2. These FGR ports may be relocated to the lower portion of the upper (secondary) furnace, across the front and rear walls. This is expected to cost in the area of +\$5.6/kW or +\$2.5M for Unit 2's additional capital cost over and above the basic SOFA system. Overall, the advanced version of SOFA is estimated to have an installed capital cost of approximately \$23/kW or \$10.1M for LOS Unit 2. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

Reduced-diameter replacement cyclone reentrant throats (boiler waterwall tubes) are hardware modifications which can be specifically designed to complement the air-staged combustion/SOFA approach and may improve the ability to increase the retention of fine coal particles during staged combustion on the Unit 2 boiler at LOS. This is estimated to cost in the area of \$18.2/kW or approximately \$8M for Unit 2. However, these capital costs were not included in the figures used in the determination of the NO<sub>x</sub> control technology cost-effectiveness for any alternatives.

#### **A2.1.1.2 Coal Reburn Capital Cost Estimates**

There are several alternatives that include a new fuel reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method. Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing LOS Unit 1 boiler's pulverizer bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal pulverizers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing cose-coupled overfire air system ports, along with new separated overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. The coal reburn system design was not expected to change the existing main burner silo/feeder arrangement, such that all main burners would remain operational. Both basic and boosted forms of SOFA for pulverized coal reburn were included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

The installed capital cost of pulverized coal reburn for LOS Unit 1 used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclone boilers, because of the need to make extension additions to the existing fuel preparation system equipment/facilities. The installed capital cost estimate of \$19.8M for LOS Unit 1's pulverized coal reburn alternative with basic SOFA used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of \$82.33/kW ( $\times 1.035 = \$85.2/\text{kW}$ ) included in a WRAP (Western Regional Air Partnership) draft report<sup>38</sup> published on their website, dated April 26, 2005. Including the estimated additional capital costs for retrofitting basic SOFA in place of CCOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to \$91.5/kW.

Including the estimated additional capital costs for boosted SOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to \$105.9/kW, bringing the estimated subtotal of LOS Unit 1's coal reburn system with boosted SOFA to \$22.9M.

As discussed in the coal reburn feasibility review, additional particulate matter collection equipment to increase PM collection capacity of LOS Unit 1 will be needed for this alternative. This was assumed to include a hybrid particulate matter collection system associated with the existing electrostatic precipitator referred to as COHPAC. A description of this technology is provided in the main report under the PM control section. The COHPAC addition due to coal reburn was estimated based on flue gas flow at the boiler design rating (2,622 mmBtu/hr) heat input rate. Installed capital cost for this COHPAC addition was \$15.7M (\$72.9/kW). This is generally described in more detail in the capital cost estimate portion of the main report for particulate matter controls, Section 4.5.1.1 for LOS Unit 2.

Addition of new electrical loads for the LOS Unit 1 boiler's pulverized/micronized coal preparation equipment, and associated with adding COHPAC to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new pulverizers/micro-mills, COHPAC, and auxiliary equipment related to the new coal reburn facility. Any capital costs for providing the additional auxiliary electrical power distribution capacity not included in the assumed project scope has not been estimated or included.

Adding the \$15.7M for the COHPAC PM collection capacity increase to the coal reburn system with basic SOFA subtotal of \$19.8M yields a total estimated installed capital cost of \$35.5M (\$164.4/kW) for this coal reburn alternative. Adding the \$15.7M for the COHPAC PM collection capacity increase to the coal reburn system with boosted SOFA subtotal of \$22.9M yields a total estimated installed capital cost of \$38.6M (\$178.8/kW) for this coal reburn alternative. This was deemed sufficient to use in the cost-effectiveness analysis for applying coal reburn to Leland Olds Station Unit 1's boiler.

The existing LOS Unit 2 boiler's crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. The coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO<sub>x</sub> emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

The installed capital cost of pulverized coal reburn for LOS Unit 2 used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of \$37.5M for LOS Unit 2's pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of \$82.33/kW ( $\times 1.035 = \$85.2/\text{kW}$ ) included in a WRAP (Western Regional Air Partnership) draft report<sup>38</sup> published on their website, dated April 26, 2005. Including the estimated additional capital costs for relocating special lignite drying system vent ports and flue gas recirculation ports previously described in the separated overfire air capital cost estimate section raised the installed capital cost estimate subtotal of LOS Unit 2's coal reburn system to \$42.1M.

As discussed in the coal reburn feasibility review, additional PM collection equipment to increase PM collection capacity of LOS Unit 2 will be needed for this alternative. This was assumed to include a hybrid particulate matter collection system associated with the existing electrostatic precipitator referred to as COHPAC. A description of this technology is provided in the main report under the PM control section. The COHPAC addition due to coal reburn was estimated based on flue gas flow at the boiler design rating (5,130 mmBtu/hr) heat input rate. Installed capital cost for this COHPAC addition was \$25.3M (\$57.5/kW). This is described in more detail in the capital cost estimate portion of the main report for particulate matter controls, Section 4.5.1.1 for LOS Unit 2.

Addition of new electrical loads for the pulverized/micronized coal preparation equipment, and associated with adding COHPAC to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new pulverizers/micro-mills, COHPAC, and auxiliary equipment related to the new coal reburn facility. Any capital costs for providing the additional auxiliary electrical power distribution capacity not included in the assumed project scope has not been estimated or included.

Adding the \$25.3M for the COHPAC PM collection capacity increase to the coal reburn system with ASOFA subtotal of \$42.1M yields a total estimated installed capital cost of \$67.425M (\$153.2/kW) for this alternative. This was deemed sufficient to use in the cost-effectiveness analysis for applying coal reburn to Leland Olds Station Unit 2's boiler.

## **A2.1.2 Capital Cost Estimates for Post Combustion Controls**

### **A2.1.2.1 SNCR Capital Cost Estimate**

The alternatives for LOS Unit 1 that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a 2004 budgetary proposal<sup>39</sup> for a nominal 240 MW unit by a vendor (Fuel Tech) with experience in supplying urea-based SNCR equipment. Circulation, metering, dilution, control, in-line and storage tank heating, water dilution, and reagent metering equipment. Estimated capital costs of \$3.9M (\$18.06/kW) include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to LOS Unit 1's 216 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to

add approximately \$1.0M (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. These adjustments result in a total installed capital cost for SNCR (without SOFA) estimated to be approximately \$3.9M plus \$1.0M = \$4.9M for 216 MW LOS Unit 1.

Adding the basicSOFA capital cost of \$1.4M yields a total estimated installed capital cost of \$6.2M (\$28.9/kW) for the SNCR with basic SOFA alternative for LOS Unit 1.

Including the estimated additional capital costs for boosted SOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to \$43.3/kW, bringing the estimated subtotal of LOS Unit 1's SNCR system with boosted SOFA (Rotamix) to \$9.3M.

The alternatives for LOS Unit 2 that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a late 2004 budgetary proposal<sup>39</sup> for a nominal 450 MW unit by a vendor (Fuel Tech) with experience in supplying urea-based SNCR equipment. Circulation, metering, dilution, control, in-line and storage tank heating, water dilution, and reagent metering equipment. The conceptual SNCR project estimates a 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck or rail). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Capacity of the SNCR system is expected to be sufficient to be operated alone or in conjunction with other NO<sub>x</sub> reduction technologies, such as advanced SOFA and Rich Reagent Injection. Estimated capital costs of \$4.9M include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately \$1.9M (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. These adjustments result in a total installed capital cost for SNCR (without advanced SOFA or RRI) estimated to be approximately \$6.7M for 440 MW LOS Unit 2. Adding the advanced SOFA capital cost of \$10.1M yields a total estimated installed capital cost of \$16.8M (\$38.3/kW) for the SNCR with ASOFA alternative for LOS Unit 2.

Addition of new electrical loads for the SNCR reagent storage, pumping, dilution, metering, and related compressed air control equipment for reagent injector cooling, will be required. For the purposes of this

preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new SNCR system and associated auxiliary equipment. Any capital costs for providing the additional auxiliary electrical power distribution capacity has not been estimated or included.

#### **A2.1.2.2 Rich Reagent Injection Capital Cost Estimate**

The alternative for LOS Unit 2 that includes Rich Reagent Injection (RRI) form of selective non-catalytic reduction systems assumes the use of urea as the effective NO<sub>x</sub> control reagent. The RRI systems' preliminary design and estimated capital costs were derived from information by the vendor licensed for this technology (Reaction Engineering International). If RRI were to be supplied without SNCR, total capital cost is assumed to be the same as SNCR with ASOFA, or \$16.8M for LOS Unit 2.

Expansion of the base SNCR alternative's reagent circulation, metering, dilution, control, in-line and storage tank heating, storage and injection equipment is assumed to be included when RRI is added to this other alternative. Individual RRI lances with multiple levels of urea reagent injection in the lower furnace will be designed and located to optimize distribution and accommodate various boiler load conditions. Capacity of the RRI system is expected to be sufficient to be operated in conjunction with other NO<sub>x</sub> reduction technologies, such as ASOFA with or without SNCR. Estimated capital costs for RRI in combination with SNCR assumed the addition was 50% of SNCR's capital costs. These adjustments result in an incremental installed capital cost for RRI estimated to be \$3.4M for LOS Unit 2 (without ASOFA or SNCR costs included in the assumed RRI+SNCR w/ ASOFA "layered" alternative). Adding the SNCR with advanced SOFA estimated capital cost of \$16.8M yields a total estimated installed capital cost of \$20.2M (\$46/kW) for this RRI+SNCR with ASOFA alternative.

Addition of new electrical loads for the RRI portion of the SNCR reagent storage, pumping, dilution, metering, and related cooling water and compressed air control equipment for reagent injector cooling and dispersion, will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the RRI portion of the new SNCR system and associated auxiliary equipment. Any capital costs for providing the additional auxiliary electrical power distribution capacity has not been estimated or included.

## **A2.2 Operating and Maintenance Cost Estimates for Leland Olds Station NO<sub>x</sub> Controls**

An evaluation was performed to determine the estimated operating, maintenance, and capital cost impacts of installing various feasible NO<sub>x</sub> control technologies on Leland Olds Station Units 1 and 2. These were estimated to be in addition to existing O&M costs to operate and maintain the LOS equipment.

The expected loss of electrical power sales from the operation of the specific NO<sub>x</sub> control alternative was included as an annualized cost, assuming \$38 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This “lost generation” was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower and loading factor, plus additional power demand for induced draft fans caused by flue gas pressure drop, pulverizers and feeders for coal reburn, and compressed air or service water consumed for injection media and lance cooling, respectively, for SNCR and RRI alternatives.
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For alternatives that involve a chemical reagent injected for NO<sub>x</sub> control, such as urea (or ammonia converted from urea), the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH<sub>3</sub> injected per mole of uncontrolled NO<sub>x</sub> emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NO<sub>x</sub> reduction fraction, and then multiplied by unit reagent cost. For SNCR-related alternatives, a December 2004 vendor proposal and subsequent followup in September 2005 is the primary basis for the reagent consumption estimates (for a specific NO<sub>x</sub> emission reduction and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the pulverizer portions of the coal reburn alternatives, which were assumed to be 3 percent.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NO<sub>x</sub> control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention.
- Heat required for reagent storage; for those alternatives that involve a chemical reagent injected for NO<sub>x</sub> control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference). All SNCR-related alternatives assume the direct use of diluted urea solution.
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NO<sub>x</sub> control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention, but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO<sub>x</sub> is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has not been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.19314) for each alternative to yield levelized total annual O&M costs.

## **A2.2.1 Combustion Controls' O&M Cost Estimates**

### **A2.2.1.1 Separated Overfire Air O&M Cost Estimates**

Operation of the basic form of SOFA on LOS Unit 1's boiler is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and overfire airflow measuring system transmitter supplying each SOFA windbox on the front and rear walls. A substantial amount of additional electricity will be consumed by the hot air booster fan for operation of the boosted form of SOFA on LOS Unit 1's boiler. Using the existing forced draft, induced draft, and

primary air fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric burner operation with SOFA. Maintenance of the new windbox-style overfire air ports is expected to be similar to the expenses associated with the existing CCOFA ports of Unit 1. Maintenance costs for alternatives that include SOFA are assumed to be 1.5 percent of the installed capital cost.

Operation of the advanced form of SOFA on LOS Unit 2's boiler is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and overfire airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. Maintenance of the new open-style overfire air ports is expected to be similar to the expenses associated with the existing flue gas recirculation ports of Unit 2. Maintenance costs for alternatives that include ASOFA are assumed to be 1.5 percent of the installed capital cost.

#### **A2.2.1.2 Coal Reburn O&M Cost Estimates**

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of each LOS boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), or possibly four micromills, are assumed to be located in a new separate building or powerhouse enclosure for each LOS boiler. A booster fan (exhauster) is assumed to be required to overcome the pressure drop across the fine-grind pulverizers or micromills and dynamic classifiers for supplementing the existing primary air system for the additional reburn fuel milling. Using the existing forced draft, induced draft, primary air (LOS Unit 1) and flue gas recirculation (LOS Unit 2) fans is not expected to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.4% (940 kW for LOS Unit 1's) and 2.5 MW for LOS Unit 2's reduction in net output was included as a cost of \$0.3M/yr and \$0.8M/yr, assuming \$38 per megawatt-hour for LOS Unit 1 and Unit 2, respectively. The twenty existing mills on Unit 1 and twelve existing coal crushers and feeders on Unit 2 used for preparing the main (burner and cyclone) fuel fraction will have approximately 25% lower

electrical demand, which was \$100,000/yr and \$150,000/yr subtracted from the additional reburn auxiliary power costs for LOS Unit 1 and Unit 2, respectively.

Maintenance of the separate reburn coal injectors is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly \$0.6M per year for LOS Unit 1 and \$1.26M per year, for LOS Unit 2.

Operation and maintenance costs of the basic and boosted forms of SOFA on LOS Unit 1's boiler, and the advanced version of SOFA on LOS Unit 2, are assumed to be included for coal reburn alternatives.

Increase in auxiliary electrical power for the COHPAC addition associated with the coal reburn alternatives for NO<sub>x</sub> control was estimated to be approximately \$0.5M/yr and \$0.8M/yr for LOS Unit 1 and LOS Unit 2 respectively. This is mostly the result of higher induced draft fan horsepower demand to overcome the resistance (pressure drop) of the filter media to the flue gas flow. Additional auxiliary electrical power must be supplied to those fans' electric motors. Maintenance of the COHPAC addition to LOS Unit 1 and LOS Unit 2 includes replacement of the filter bags, and general maintenance expenses. This was assumed to be approximately \$0.4M/yr and \$0.8M/yr for LOS Unit 1 and LOS Unit 2 respectively. Section 4.5.1.2 of the main report for LOS Unit 2 describes the O&M cost estimate portion for particulate matter controls in more detail.

## **A2.2.2 Post-Combustion NO<sub>x</sub> Controls' O&M Cost Estimates**

### **A2.2.2.1 SNCR O&M Cost Estimates**

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of LOS Unit 1 and Unit 2. Urea supply is believed to be available regionally, with an estimated unit cost assumed to average \$379/ton delivered as a 50% concentration aqueous solution (2006\$). This unit price is volatile, and changes primarily on the basis of the unit cost of natural gas. Consumption of aqueous urea reagent was derived from preliminary numbers included in a late 2004 budgetary proposal by a vendor of urea-based SNCR equipment (Fuel Tech), allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. This estimated urea consumption rate is significantly higher than that predicted by equations published in the EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO<sub>x</sub> Controls – NO<sub>x</sub> Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation<sup>40</sup>.

New electrical loads are required for high flow urea circulation, water dilution, in-line and storage tank heating, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in the EPA OAQPS SNCR Cost Manual<sup>40</sup>.

Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

The O&M costs associated with an SNCR system for LOS Unit 1 and Unit 2 assumes that no additional operating labor is required, as suggested in the EPA OAQPS SNCR Cost Manual<sup>40</sup>.

Operation and maintenance costs of the basic and boosted forms of SOFA on LOS Unit 1's boiler, and the advanced version of SOFA on LOS Unit 2, are assumed to be included for SNCR alternatives that include SOFA technology.

#### **A2.2.2.2 RRI O&M Cost Estimates**

Operating and maintenance costs for Rich Reagent Injection assumes this technology was combined with the advanced form of SOFA and SNCR for LOS Unit 2. Consumption of the 50% concentration aqueous urea reagent for RRI system operation without including the reagent consumed by the SNCR system was based upon a reagent consumption rate of two times the comparable SNCR urea usage rate for the same uncontrolled NO<sub>x</sub> emission conditions and percent NO<sub>x</sub> reduction. The estimated aqueous urea consumption for the combined RRI+SNCR systems was determined by simple addition of the usage of the individual technologies, based on their estimated individual performance contributions.

Additions to the new electrical loads assumed for SNCR are required for increased capacity high flow urea circulation, water dilution, in-line and storage tank heating, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in the EPA OAQPS SNCR Cost Manual<sup>40</sup>. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available. The additional new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and

distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost for this alternative.

Similar to SNCR, the O&M costs associated with an RRI+SNCR system for LOS Unit 2 assumes that no additional operating labor is required, as suggested in the EPA OAQPS SNCR Cost Manual<sup>40</sup>.

#### A2.2.4 Summary of O&M Cost Estimates for LOS NO<sub>x</sub> Controls

The results of this evaluation for expected operating and maintenance costs for the individual NO<sub>x</sub> control alternatives are summarized in the main report (Sections 2.4 and 2.5). The expected O&M costs are dependent upon the assumptions involving reductions in unit availability (uptime) and capacity included in Tables A.2-1 through A.2-4. The O&M costs associated with electrical power demands and usage are shown in Tables A.2-5 and A.2-6. The O&M costs for expected NO<sub>x</sub> reagent usage are shown in Tables A.2-7 and A.2-8.

**TABLE A.2-1 – Expected Availability Reductions for LOS Unit 1 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average Availability <sup>2</sup>	Estimated Annual Average Operating Time, hrs/yr <sup>3</sup>	Estimated Annual Average Outage Time, hrs/yr <sup>4</sup>	Estimated Annual Average Lost Operating Time, hrs/yr <sup>5</sup>
G	Coal Reburn w/ boosted SOFA	0.990	8,672	88	88
F	Coal Reburn w/ basic SOFA	0.990	8,672	88	88
E	SNCR with boosted SOFA	0.990	8,672	88	88
D	SNCR with basic SOFA	0.990	8,672	88	88
C	SNCR with Close-Coupled SOFA	0.990	8,672	88	88
B	Boosted SOFA	1.000	8,760		
A	Separated OFA (basic)	1.000	8,760	0	0

<sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.

<sup>2</sup> – Baseline availability is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NO<sub>x</sub> control technique.

<sup>3</sup> – Annual operating time is annual availability multiplied by 8760 hrs/yr of possible uptime.

<sup>4</sup> – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.

<sup>5</sup> – Annual lost operating time resulting from the implementation of the individual NO<sub>x</sub> control technique is the difference between the baseline and expected annual outage times.

**TABLE A.2-2 – Expected Availability Reductions for LOS Unit 2 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average Availability <sup>2</sup>	Estimated Annual Average Operating Time, hrs/yr <sup>3</sup>	Estimated Annual Average Outage Time, hrs/yr <sup>4</sup>	Estimated Annual Average Lost Operating Time, hrs/yr <sup>5</sup>
D	RRI+SNCR w/ ASOFA	0.990	8,672	88	88
C	SNCR w/ ASOFA	0.990	8,672	88	88
B	Coal Reburn w/ ASOFA	0.985	8,629	131	131
A	Advanced SOFA (ASOFA)	1.000	8,760	0	0

<sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.

<sup>2</sup> – Baseline availability is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NO<sub>x</sub> control technique.

<sup>3</sup> – Annual operating time is annual availability multiplied by 8760 hrs/yr of possible uptime.

<sup>4</sup> – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.

<sup>5</sup> – Annual lost operating time resulting from the implementation of the individual NO<sub>x</sub> control technique is the difference between the baseline and expected annual outage times.

**TABLE A.2-3 – Expected Capacity Reductions for LOS Unit 1 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average Running Plant Capacity Factor <sup>2</sup>	Estimated Annual Average Electricity Generation Reduction MW-hrs/yr <sup>3</sup>	Estimated Annual Average Generation Reduction Cost, K\$/yr <sup>4</sup>
G	Coal Reburn w/ boosted SOFA	0.995	18,827	715
F	Coal Reburn w/ basic SOFA	0.995	18,827	715
E	SNCR with boosted SOFA	0.999	18,893	718
D	SNCR with basic SOFA	0.999	18,893	718
C	SNCR with Close-Coupled SOFA	0.999	18,893	718
B	Boosted SOFA	1.000	0	0
A	Separated OFA (basic)	1.000	0	0

<sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.

<sup>2</sup> – Baseline running plant capacity factor is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NO<sub>x</sub> control technique.

<sup>3</sup> – Annual electricity generation lost is annual lost operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the unit nameplate gross output capacity rating: 216 MW for LOS Unit 1.

<sup>4</sup> – Annual electricity generation lost cost is the annual electricity generation lost (MW-hrs/yr) resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the incremental value of electricity generation, assumed to be \$38.00/MW-hr. All cost figures in 2005 dollars.

**TABLE A.2-4 – Expected Capacity Reductions for LOS Unit 2 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average Running Plant Capacity Factor <sup>2</sup>	Estimated Annual Average Electricity Generation Reduction MW-hrs/yr <sup>3</sup>	Estimated Annual Average Generation Reduction Cost, K\$/yr <sup>4</sup>
D	RRI+SNCR w/ ASOFA	0.999	38,486	1,462
C	SNCR w/ ASOFA	0.999	38,486	1,462
B	Coal Reburn w/ ASOFA	0.995	57,527	2,186
A	Advanced SOFA (ASOFA)	1.000	0	0

- <sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.
- <sup>2</sup> – Baseline running plant capacity factor is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NO<sub>x</sub> control technique.
- <sup>3</sup> – Annual electricity generation lost is annual lost operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the unit nameplate gross output capacity rating: 440 MW for LOS Unit 2.
- <sup>4</sup> – Annual electricity generation lost cost is the annual electricity generation lost (MW-hrs/yr) resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the incremental value of electricity generation, assumed to be \$38.00/MW-hr. All cost figures in 2005 dollars.

**TABLE A.2-5 – Expected Auxiliary Electrical Power Demand and Usage for LOS Unit 1 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average NO <sub>x</sub> Equipment Auxiliary Electrical Demand & Usage		
		Total Net Demand <sup>2</sup> kW	Net Generation Reduction kW-hrs/yr <sup>3</sup>	Annual Cost, K\$/yr <sup>4</sup>
G	Coal Reburn w/ boosted SOFA	3,900	33,864,255	1,287
F	Coal Reburn w/ basic SOFA	2,220	19,160,595	728
E	SNCR with boosted SOFA	1,713	15,002,180	570
D	SNCR with basic SOFA	37	318,749	12
C	SNCR with Close-Coupled SOFA	49	423,483	16
B	Boosted SOFA	1,680	14,712,420	559
A	Separated OFA (basic)	1	8,760	0.3

- <sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.
- <sup>2</sup> – The estimated NO<sub>x</sub> equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.

- <sup>3</sup> – The estimated annual NO<sub>x</sub> equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
- <sup>4</sup> – The estimated annual NO<sub>x</sub> equipment auxiliary electrical power demand electricity cost is the estimated annual kW-hrs/yr for these alternatives resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be \$38.00/MW-hr. All cost figures in 2005 dollars.

**TABLE A.2-6 – Expected Auxiliary Electrical Power Demand and Usage for LOS Unit 2 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NO <sub>x</sub> Control Technique	Estimated Annual Average NO <sub>x</sub> Equipment Auxiliary Electrical Demand & Usage		
		Total Net Demand <sup>2</sup> kW	Net Generation Reduction kW-hrs/yr <sup>3</sup>	Annual Cost, K\$/yr <sup>4</sup>
D	RRI+SNCR w/ ASOFA	285	2,464,270	94
C	SNCR w/ ASOFA	156	1,349,578	51
B	Coal Reburn w/ ASOFA	5,395	46,313,786	1,760
A	Advanced SOFA (ASOFA)	1	8,760	0.3

- <sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.
- <sup>2</sup> – The estimated NO<sub>x</sub> equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.
- <sup>3</sup> – The estimated annual NO<sub>x</sub> equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
- <sup>4</sup> – The estimated annual NO<sub>x</sub> equipment auxiliary electrical power demand electricity cost is the estimated annual kW-hrs/yr for these alternatives resulting from the implementation of the individual NO<sub>x</sub> control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be \$38.00/MW-hr. All cost figures in 2005 dollars.

**TABLE A.2-7 – Expected NOx Reagent Usage and Cost Estimates  
for LOS Unit 1 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NOx Control Technique	NOx Reduction Reagent Urea Usage (undiluted, as delivered)			NOx Reduction Reagent Dilution Water Usage <sup>3</sup>	
		lbs/hr	tons/yr	\$1000/yr	1000 gal/yr	\$1000/yr
E	SNCR with boosted SOFA	637	2,764	1,050	2,645	1.1
D	SNCR with basic SOFA	765	3,345	1,270	3,175	1.3
C	SNCR with Close-Coupled SOFA	960	4,199	1,590	3,985	1.6

- <sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.
- <sup>2</sup> – Reagent consumption derived from vendor (Fuel Tech) December 2004 proposal for SNCR. Reagent usage for RRI is twice the amount of urea usage for comparable SNCR conditions and percent reduction. All cost figures in 2006 dollars.
- <sup>3</sup> – Reagent dilution water usage assumes filtered steam turbine condenser recirculated cooling water is added to create a 10% urea concentration (4 parts water to 1 part aqueous urea at 50% concentration as delivered) prior to injection. Dilution water unit cost assumed to be \$0.40 per thousand gallons.

**TABLE A.2-8 – Expected NOx Reagent Usage and Cost Estimates  
for LOS Unit 2 NO<sub>x</sub> Controls**

Alt. # <sup>1</sup>	NOx Control Technique	NOx Reduction Reagent Urea Usage (undiluted, as delivered)			NOx Reduction Reagent Dilution Water Usage <sup>3</sup>	
		lbs/hr	tons/yr	\$1000/yr	1000 gal/yr	\$1000/yr
D	RRI+SNCR w/ ASOFA	5,550	24,000	9,100	23,100	9
C	SNCR w/ ASOFA	2,920	12,600	4,800	12,100	5

- <sup>1</sup> – Alternative number has been previously assigned from least removal to highest removal percentage.
- <sup>2</sup> – Reagent consumption derived from vendor (Fuel Tech) December 2004 proposal for SNCR. Reagent usage for RRI is twice the amount of urea usage for comparable SNCR conditions and percent reduction. All cost figures in 2006 dollars.
- <sup>3</sup> – Reagent dilution water usage assumes filtered steam turbine condenser recirculated cooling water is added to create a 10% urea concentration (4 parts water to 1 part aqueous urea at 50% concentration as delivered) prior to injection. Dilution water unit cost assumed to be \$0.40 per thousand gallons.

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## Appendix A.3 - U.S. Cyclone NOx Reduction Projects Summary

### ***SEPARATED OVERFIRE AIR***

#### **Cyclone-Fired Boilers**

Alliant Energy (formerly Wisconsin Power & Light)

Edgewater Unit 4                      Crushed Coal, single-wall cyclone-fired                      1969 vintage  
330 MW B&W boiler                      PRB/Illinois Coal blend

Boiler has 7 cyclone burners, arranged “3 over 4” style, on front wall, and fired a blend of 80% western subbituminous (PRB) coal, with 20% Illinois bituminous coal sometimes amended with 3% tire-derived fuel. After cyclone barrel reentrant throat and damper modifications allow firing up 100% PRB coal. A SOFA system began operation in mid-2001<sup>(1)</sup>, which initially reduced NOx emissions approx. 40-50% reduction from 1.08-1.15 (assume average of 1.10) down to 0.3 to 0.5 lb/mmBtu (assume average of 0.39) with typical cyclone air-staging (cyclone SR not stated but believed to be around 0.90)<sup>(2)</sup>. Subsequent testing and optimized full load SOFA operation at deeper cyclone air-staging (SRs believed to be ≤ 0.90) dropped NO<sub>x</sub> to average of 0.27 lb/mmBtu in 2003<sup>(2)</sup>.

Source: <sup>(1)</sup>EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document.

<sup>(2)</sup>Alliant/RMT 2003 Technical Paper. Also listed in <sup>(3)</sup>B&W Sept. 2002 OFA port experience list.

Ameren UE (formerly Union Electric Co.)

Sioux Unit 1                      Crushed Coal, opposed-wall cyclone-fired                      1969 vintage  
500 MW B&W boiler                      PRB/Illinois Coal blend

Boiler has 10 cyclone burners, arranged “2 over 3” style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel. A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 53% reduction from 1.1-1.3 (assume average of 1.19) down to 0.55 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0)<sup>(4)</sup>. Subsequent testing and full load operation at deeper cyclone air-staging has dropped NO<sub>x</sub> with SOFA alone to 0.38 lb/mmBtu in 2002, around 0.3 lb/mmBtu in 2004<sup>(4)</sup>, and as low as 0.20 lb/mmBtu in 2005 (SRs ≤ 0.90)<sup>(7)</sup>.

Source: REI 2002<sup>(4)</sup>, 2003<sup>(5)</sup>, 2004<sup>(6)</sup>, 2005<sup>(7)</sup> Technical Papers.

Ameren UE (formerly owned by Central Illinois Public Service)

Coffeen Unit 1                      Crushed Coal, opposed-wall cyclone-fired                      1965 vintage  
600 MW B&W boiler                      Illinois Coal (midwestern bituminous)

Unit 2 boiler has 14 cyclone burners, arranged “3 over 4” style, on front and rear walls.

SOFA system began operation in early-2000; average annual NOx emissions approx. 1.03 lb/mmBtu down 27% to 0.75 lb/mmBtu average<sup>(1)</sup>.

Source: EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document<sup>(1)</sup>. Also listed in B&W Sept. 2002 OFA port experience list<sup>(3)</sup>.

Dominion Resources (formerly owned by Commonwealth Edison)

Kincaid Units 1 and 2                      Crushed Coal, opposed-wall cyclone-fired                      1967, 1968 vintage  
660 MW B&W boilers                      PRB Coal

Boilers have 14 cyclone burners, arranged “3 over 4” style, on front and rear walls.

SOFA systems with 11 ports each began operation in mid-2000; avg. 1999 annual NOx emissions approx. 0.91 and 0.94 lb/mmBtu, decreasing 27% in 2001 to 0.66 and 0.69 lb/mmBtu avg (respectively)<sup>(1)</sup>.

Source: EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document<sup>(1)</sup>. Also listed in B&W Sept. 2002 OFA port experience list<sup>(3)</sup>.

Tennessee Valley Authority (TVA)                      Crushed Coal, cyclone-fired,                      1959 vintage  
Allen Station Units 2 & 3 (TN) (seven cyclones)  
300 MW B&W boilers                      PRB & western bituminous coal blend  
GE-EER Overfire air (duplicate of Allen 1), 1999 startup  
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85  
lb/mmBtu on Units #2 and 3 at full load<sup>(8)</sup>.  
Source: GE-EER Sept. 2005 experience list<sup>(8)</sup>.

**TABLE A.3-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations<sup>(1)</sup>**

<u>Facility Name</u>	<u>Installation Date</u>	<u>Comments</u>
Allen Station Unit 2	Installed 1999*	Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003 <sup>(9)</sup>	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001 <sup>(9)</sup>	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000 <sup>(9)</sup>	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998 <sup>(9)</sup>	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002 <sup>(9)</sup>	
Nelson Dewey Unit 2	Installed 2002 <sup>(9)</sup>	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000 <sup>(9)</sup>	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001 <sup>(9)</sup>	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004 <sup>(9)</sup>	
Thomas Hill Unit 2	Installed November 2000 <sup>(9)</sup>	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.

Source: <sup>(1)</sup> US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)

\* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)

<sup>(9)</sup> Burns & McDonnell internal database.

**TABLE A.3-2 – Cyclone-Fired Boiler Reburn Overfire Air Retrofit Installations<sup>(1)</sup>**

<u>Facility Name</u>	<u>Installation Date</u>	<u>Comments</u>
Allen Station Unit 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
CP Crane Unit 1*	Installed 1999	OFA w/ CGR retrofit
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Lakeside Unit 7†	Installed 1992*	OFA w/ CGR retrofit; DOE-NETL
Kodak Park #15 Boiler†	Installed 1997*	OFA w/ micronized coal retrofit; DOE-NETL
Kodak Park #43 Boiler	Installed 1995	OFA w/ CGR retrofit
Kodak Park #41 Boiler	Installed 1998	OFA w/ CGR retrofit
Kodak Park #42 Boiler	Installed 1998	OFA w/ CGR retrofit
Nelson Dewey Unit 2†	Installed 1991	OFA w/ pulverized coal reburn; DOE-NETL

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project for reburn.

Source: <sup>(1)</sup>US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NO<sub>x</sub> Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)

\* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)

† U.S. Department of Energy National Energy Technology Laboratory Clean Coal Technology Demonstration Program project (not commercially available at time of implementation)<sup>(11)</sup>

## ***REBURN – GAS, CONVENTIONAL***

### **Cyclone-Fired Boilers**

Constellation Energy (formerly Baltimore Gas & Electric)

C.P. Crane Station, Units 1 & 2 (MD)      Crushed Coal, cyclone-fired, eastern bituminous coal  
2 x 200 MW B&W boilers      (four cyclones each)      1961, 1963 vintage

GE-EER Conventional Gas Reburn, 1999 startup

Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)

GE-EER claimed Gas Reburn with OFA lowered NO<sub>x</sub> between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation<sup>(8)</sup>. No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.

Another technical paper showed this installation of CGR operated with 25 percent reburn fuel<sup>(11)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

City Water, Light & Power

Lakeside Unit 7      Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal  
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones)      1961 vintage

Springfield, IL      DOE Clean Coal demonstration project (included sorbent injection)

GE-EER conventional gas reburn w/ OFA      1992 startup (CGR not currently operating)

Vendor claimed to lower NO<sub>x</sub> by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu<sup>(8)</sup>. A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NO<sub>x</sub> emissions<sup>(11)</sup>.

A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NO<sub>x</sub> 60% from 0.97 to 0.39 lb/mmBtu<sup>(10)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(11)</sup>; DOE-NETL 2004 Reburn Conference Technical paper<sup>(10)</sup>.

Eastman Kodak Company

Kodak Park Boilers 41 & 42      Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage  
400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)

Rochester, NY      eastern bituminous coal

B&W conventional gas reburn w/ OFA      December 1998, July 1998 startups (still operating)

Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR believed not <1.0}.

B&W claimed reburn with OFA lowered NO<sub>x</sub> by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu.

B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NO<sub>x</sub> (73% reduction)<sup>(12)</sup>.

Another technical paper showed NO<sub>x</sub> lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel<sup>(10)</sup>.

Source: B&W Technical Paper<sup>(12)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

## ***REBURN – GAS, CONVENTIONAL, continued***

### **Cyclone-Fired Boilers**

Eastman Kodak Company

Kodak Park Boiler 43      Crushed Coal, front-wall cyclone-fired      1968 vintage

600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)

Rochester, NY      eastern bituminous coal

B&W conventional gas reburn 1995 startup (still operating)  
 Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR believed not <1.0}  
 B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction)<sup>(12)</sup>.  
 Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel<sup>(10)</sup>.  
 Source: 2004 B&W Technical Paper<sup>(12)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

Tennessee Valley Authority (TVA)  
 Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage  
 300 MW B&W boiler PRB & western bituminous coal blend fired  
 GE-EER Conventional Gas Reburn, 1998 startup  
 Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.  
 Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers)<sup>(8)</sup>.  
 Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel<sup>(11)</sup>.  
 Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

***REBURN – COAL, CONVENTIONAL***

**Cyclone-Fired Boilers**

Alliant Energy (formerly Wisconsin Power & Light)  
 Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage  
 110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +  
 4 OFA ports across rear wall, aligned vertically in columns.  
 US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)  
 B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load<sup>(13)</sup>. Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list<sup>(3)</sup>.  
 B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated<sup>(13)</sup>.  
 Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel<sup>(11)</sup>.  
 Source: 2004 B&W Technical Paper<sup>(12)</sup>; DOE-NETL 2004 Reburn Conference Technical paper<sup>(11)</sup>; B&W case history (from website, dated 1997)<sup>(13)</sup>.

***REBURN – COAL, MICRONIZED, CONVENTIONAL***

**Cyclone-Fired Boilers**

Eastman Kodak Company

Kodak Park #15 Boiler                      Crushed Coal, front-wall cyclone-fired, 1956 vintage

400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)

Rochester, NY                                      eastern bituminous coal

GE-EER micronized coal reburn 1996 initial startup (operating since 1997)

Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones<sup>(15)</sup>. GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.

GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included<sup>(8)</sup>.

Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel<sup>(11)</sup>.

Source: DOE Topical Report Number 14 (May 1999)<sup>(14)</sup>; GE-EER experience list<sup>(8)</sup>; DOE-NETL 2004 Reburn Conference Technical paper<sup>(10)</sup>.

***REBURN – FUEL LEAN GAS REBURN***

**Cyclone-Fired Boilers**

Midwest Generation (formerly Commonwealth Edison)

Joliet Station 9, Unit 6                      Crushed Coal, opposed-wall cyclone-fired (nine cyclones)

340 MW B&W boiler                      1959 vintage, 1997 startup (FLGR has since been decommissioned)

Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)<sup>(10)</sup>.

Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel<sup>(15)</sup>.

Source: DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>; NGB Technologies Technical Paper<sup>(15)</sup>.

***REBURN – FUEL LEAN GAS REBURN w/ SNCR***

**Cyclone-Fired Boilers**

Owensboro Municipal Utilities (KY)                      Crushed Coal, front-wall cyclone-fired

Elmer Smith Unit 1                                      (three cyclones)                                      1965 vintage

150 MW B&W boiler

CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip<sup>(16)</sup>.

Source: REI 2001 Technical paper<sup>(16)</sup>.

***SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION***

**Cyclone-Fired Boilers**

Conectiv (formerly Atlantic Electric)

BL England Unit 1                      Crushed Coal, single-wall cyclone-fired                                      1962 vintage

138 MW B&W boiler                      aqueous urea SNCR, 1995 startup                                      eastern bituminous coal

Boiler has only 3 cyclone burners, arranged "1 over 2" style.

RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx

baseline<sup>(1)</sup> for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85<sup>(17)</sup>.

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing<sup>(18)</sup>.

Source: RJM experience list<sup>(17)</sup>; 2001 REI Technical Paper<sup>(18)</sup>;  
(Also listed in ICAC SNCR 2000 White Paper<sup>(19)</sup>).

Conectiv (formerly Atlantic Electric)

BL England Unit 2                      Crushed Coal, cyclone-fired, single-wall-fired                      1964 vintage  
160 MW B&W boiler                      SNCR, 1996 startupeastern bituminous coal  
RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air)<sup>(17)</sup>.

An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%<sup>(17)</sup>.

Source: RJM experience list<sup>(17)</sup>. (Also listed in ICAC SNCR 2000 White Paper<sup>(19)</sup>).

AmerenUE (formerly Union Electric Co.)

Sioux Unit 1                      Crushed Coal, opposed-wall cyclone-fired                      1969 vintage  
500 MW B&W boiler                      Rich Reagent Injection demonstration testing in 2001  
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.

**Tested** in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip<sup>(4)</sup>.

**Tested** in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip<sup>(4)</sup>.

(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)<sup>(4)</sup>.

**Operation** in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)<sup>(5,6)</sup>.

**Tested** in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NO<sub>x</sub> reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NO<sub>x</sub> reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip 10 ppm or less. RRI+SNCR w/ SOFA NO<sub>x</sub> reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NO<sub>x</sub> reduction with ammonia slip around 1-2 ppm <sup>(7)</sup>.  
Source: REI 2002<sup>(4)</sup> and 2003<sup>(5)</sup> Technical Papers; REI 2004<sup>(6)</sup> Technical paper; REI 2005<sup>(7)</sup> Technical paper.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.3-3. This list includes at least eight cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission reductions listed in Table A.3-3 for SCR systems are for clean reactor catalyst and ideal operating conditions.

**TABLE A.3-3 – Cyclone-Fired Boiler High-Dust SCR Installations**

Facility <sup>1</sup>	Unit Size <sup>2</sup> , MW	Tested Control Efficiency <sup>3</sup>	Tested Outlet NO <sub>x</sub> Emission Rate (lb/mmBtu) <sup>3</sup>	2003 Ozone Season Average NO <sub>x</sub> Emission Rate <sup>4</sup> (lb/mmBtu)
Allen 1, 2, & 3 <sup>5,6</sup>	330 ea.	91.1/NAD <sup>7</sup> /88.7	0.070/NAD <sup>7</sup> /0.088	0.088/0.077/0.086
Baldwin 1 <sup>5,6</sup>	600 <sup>3</sup>	82.9	0.072	0.238
Baldwin 2 <sup>5,6</sup>	605 <sup>3</sup>	83.5	0.067	0.286
Bailly 8 <sup>5,6</sup>	422	NAD <sup>7</sup>	NAD <sup>7</sup>	0.84
Coffeen 1 <sup>5,6</sup>	389	NAD <sup>7</sup>	NAD <sup>7</sup>	0.114
Coffeen 2 <sup>5,6</sup>	617	NAD <sup>7</sup>	NAD <sup>7</sup>	0.120
Dallman 31 & 32	207	NAD <sup>6</sup>	NAD <sup>6</sup>	0.149/0.146
Kincaid 1 & 2 <sup>5,6</sup>	660 <sup>3</sup> ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1 <sup>5,8</sup>	114	50.5 <sup>9</sup>	0.148	0.158
Merrimack 2	346	51.3 <sup>9</sup>	0.155	0.171
Michigan City 12 <sup>5,10</sup>	540	84.2	0.109	0.418
New Madrid 1 & 2 <sup>8,10</sup>	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2 <sup>5,6</sup>	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3 <sup>5,6</sup>	1150	89.1	0.088	0.658
Schahfer 14 <sup>5,10</sup>	540	83.5	0.106	0.478

<sup>1</sup> – original design fuel for all listed cyclone boilers was bituminous coal

<sup>2</sup> – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

<sup>3</sup> – Burns & McDonnell internal database.

<sup>4</sup> – as reported to US EPA, available from their website at <http://cfpub.epa.gov/gdm/index.cfm>

<sup>5</sup> – includes application of separated overfire air for combustion NO<sub>x</sub> control

<sup>6</sup> – current fuel believed to be a blend of subbituminous and bituminous coals

<sup>7</sup> – NAD = no published data from SCR emission testing found on these units.

<sup>8</sup> – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit

<sup>9</sup> – Design NO<sub>x</sub> removal efficiency is higher, approx. 90%.

<sup>10</sup> – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO<sub>x</sub> was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO<sub>x</sub> removal efficiency and 5 ppm ammonia slip. SCR commercial service date July 20, 1999<sup>(20)</sup>.

Source: Babcock Borsig Power 2000 technical paper on SCRs<sup>(20)</sup>.

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO<sub>x</sub> was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal<sup>(21)</sup>, which exceeded the 65% requirement to

achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO<sub>x</sub> removal efficiency and 5 ppm ammonia slip<sup>(22)</sup>.

Source: NETL-DOE Clean Coal Technology 1997 technical paper on SCRs<sup>(21)</sup>; 1997 ICAC White Paper on SCRs<sup>(22)</sup>.

Northern Indiana Public Service Company (NIPSCO)

Bailly Unit 8                                      Crushed Coal, cyclone-fired, opposed-wall-fired                                      1968 vintage

360 MW B&W boiler                                      Urea/ammonia conversion for high-dust SCR, 2004 startup

Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.

Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia vapor reagent ahead of high-dust SCR<sup>(23)</sup>. An OFA system was retrofitted in 2000<sup>(9)</sup>.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>; Burns & McDonnell internal database<sup>(9)</sup>.

Northern Indiana Public Service Company (NIPSCO)

Michigan City Unit 12                                      Crushed Coal, cyclone-fired, opposed-wall-fired                                      1974 vintage

520 MW B&W boiler                                      Urea/ammonia conversion for high-dust SCR, 2003 startup

Boiler fires western subbituminous (PRB) coal.

Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia vapor reagent ahead of high-dust SCR<sup>(23)</sup>. An OFA system was retrofitted in 1998<sup>(9)</sup>.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>; Burns & McDonnell internal database<sup>(9)</sup>.

Northern Indiana Public Service Company (NIPSCO)

Schahfer Unit 14                                      Crushed Coal, cyclone-fired, opposed-wall-fired                                      1975 vintage

520 MW B&W boiler                                      Urea/ammonia conversion for high-dust SCR, 2004 startup

Boiler fires western subbituminous (PRB) coal.

Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia vapor reagent ahead of high-dust SCR<sup>(23)</sup>. An OFA system was retrofitted in 2000<sup>(9)</sup>.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>; Burns & McDonnell internal database<sup>(9)</sup>.

Pulverized coal-fired utility boilers in the United States that have been retrofitted with low-dust SCR technology are listed in Table A.3-4.

**TABLE A.3-4 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations**

<b>Operator/Facility<sup>1,2</sup></b>	<b>SCR Startup Date<sup>3</sup></b>	<b>Average NO<sub>x</sub> Emission Rates<sup>4</sup> (lb/mmBtu)</b>	<b>Unit Size<sup>5</sup>, MW</b>
AEP/Cardinal Unit 3 <sup>6</sup>	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1 <sup>7</sup>		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4 <sup>7,8</sup>	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1 <sup>8</sup>	(2001)	0.47 / 0.33 / 0.126	685
Constellation/Brandon Shores Unit 2 <sup>8</sup>	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06 <sup>9</sup>	666
Dynegy Midwest Gen/Havana Unit 6 <sup>10</sup>	(2000)	0.46 / 0.20 / 0.102 <sup>9</sup>	488
PSEG Power LLC / Mercer Unit 1 <sup>11</sup>	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2 <sup>11</sup>	(2004)	- / (0.76) / N/A	320

<sup>1</sup> – Burns & McDonnell internal database.

<sup>2</sup> – Current fuel is eastern or midwestern bituminous coal, except Havana

<sup>3</sup> – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NO<sub>x</sub> Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.

<sup>4</sup> – The three values are “Pre-control average”, “2004 annual average”, and “2003 ozone season average” NO<sub>x</sub> emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NO<sub>x</sub> Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website:

<http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b>.

Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA’s website at

<http://cfpub.epa.gov/gdm/index.cfm>, includes application of separated overfire air for combustion NO<sub>x</sub> control where applicable.

<sup>5</sup> – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

<sup>6</sup> – This boiler has low-NO<sub>x</sub> burners for combustion controls.

<sup>7</sup> – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.

<sup>8</sup> – This boiler has low-NO<sub>x</sub> burners and overfire air for combustion controls.

<sup>9</sup> – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.

<sup>10</sup> – This boiler’s current fuel is believed to be subbituminous coal.

<sup>11</sup> – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.

N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

***LOW NO<sub>x</sub> BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR***

**Pulverized coal-fired boilers**

AEP Cardinal Unit 1 Pulverized Coal cell-burner, opposed wall-fired B&W boiler  
600 MW (nominal) 1967 vintage; Low NO<sub>x</sub> burners installed in October 1998  
Produced 0.75 lb/mmBtu NO<sub>x</sub> post-LNB install baseline at full load.  
LNBS reduced NO<sub>x</sub> 57% from 1.20 down to 0.52<sup>(24)</sup>, produce NO<sub>x</sub> at approx. 0.57 lb/mmBtu at min. load  
w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO<sub>x</sub> at approx. 585 MW (top of load range  
tested, NO<sub>x</sub> range 0.73 to 0.86 lb/mmBtu)<sup>(25)</sup>.  
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power  
with DB Riley (now Babcock Power) CCV type low NO<sub>x</sub> burners.  
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list<sup>(24)</sup>; 2000 Fuel Tech technical paper<sup>(25)</sup>.  
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)

Asheville Unit 1 Pulverized Coal, front wall fired  
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup  
Low NO<sub>x</sub> burners were previously retrofitted in 1997 without separated overfire air<sup>(1)</sup>. NO<sub>x</sub> reduction  
was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu<sup>(1)</sup> down to 0.58 lb./mmBtu<sup>(26)</sup>.  
(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).  
Source: 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet<sup>(1)</sup>;  
CP&L and Fuel Tech 2001 Technical paper<sup>(26)</sup>.

Carolina Power & Light (Progress Energy)

Cape Fear Unit 5 Pulverized Coal, Tangentially-fired  
154 MW CE boiler 1956 vintage; eastern bituminous coal  
ROFA startup in 2000  
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air  
system claimed to lower NO<sub>x</sub> without retrofitting low-NO<sub>x</sub> burners. This was the first U.S. installation of  
Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.  
CP&L technical paper claimed to lower NO<sub>x</sub> 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to  
0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000<sup>(27)</sup>.  
Source: CP&L 2002 Technical paper<sup>(27)</sup>.  
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)

Cape Fear Unit 6 Pulverized Coal, Tangentially-fired  
175 MW CE boiler twin-furnace (eight corner), 1958 vintage; eastern bituminous coal  
ROFA startup in 2001  
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.  
CP&L technical paper shows ROFA alone reduced NO<sub>x</sub> 57% from full-load pre-ROFA baseline 0.54  
lb/mmBtu to a NO<sub>x</sub> emission rate of 0.23 lb/mmBtu.<sup>(27)</sup>  
Source: CP&L 2002 Technical paper<sup>(27)</sup>.  
(Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)

Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage  
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage  
B&W, DB Riley boilers eastern bituminous coal  
REI performed CFD modeling on both units for potential SNCR application.  
Unit 3 has Riley Low NO<sub>x</sub> burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air  
ports, (66) side wall OFA slots, claimed baseline NO<sub>x</sub> around 0.37 lb/mmBtu w/o SNCR<sup>(28)</sup>.

Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NO<sub>x</sub> around 0.44 lb/mmBtu w/o SNCR<sup>(28)</sup> {furnace has “Mae West” belt}.

Riley provided 16 CCV low-NO<sub>x</sub> burners for Unit 3 in 1994, and claimed to reduce NO<sub>x</sub> emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu<sup>(24)</sup>.

Source: REI 1999 Technical Paper<sup>(28)</sup>; Riley Power (Babcock Power Inc.) 8/16/04 experience list<sup>(24)</sup>.

(Also see SNCR installation summaries for pulverized coal boilers).

***LOW NO<sub>x</sub> BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued***  
**Pulverized coal-fired boilers**

Dayton Power & Light                      Pulverized Coal, Tangentially-fired

Killen Station, Unit 2                      1955 vintage

632 MW    CE boiler, bituminous Illinois coal

GE-EER provided low-NO<sub>x</sub> burners in 1999. Vendor claimed full load NO<sub>x</sub> was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu<sup>(8)</sup>.

Source: GE Energy (formerly GE-EER) experience list September 29, 2005<sup>(8)</sup>.

(Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power)                      Pulverized Coal, wall-fired

Havana Station, Unit 6                      1978 vintage

460 MW    B&W boiler, bituminous Illinois coal

GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000.

Vendor claimed full load NO<sub>x</sub> was unchanged from 0.38 lb/mmBtu baseline<sup>(8)</sup>.

Source: GE Energy (formerly GE-EER) experience list September 29, 2005<sup>(8)</sup>. (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power)                      Pulverized Coal, Tangentially-fired

Vermillion Station, Unit 1                      1955 vintage

82 MW    CE boiler, bituminous Illinois coal

This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a “Rotamix” SNCR + ROFA system, without low-NO<sub>x</sub> burners.

Mobotec 2004 technical paper claimed to lower full load NO<sub>x</sub> by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR).<sup>(29)</sup>

Source: Mobotec 2004 technical paper<sup>(29)</sup>.

(Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power                                      Pulverized coal, opposed wall-fired,

Harlee Branch Unit 1                      250 MW B&W boiler, 1965 vintage                      2003 startup

Harlee Branch Unit 2                      359 MW Riley boiler, 1967 vintage                      1998 startup

B&W provided 24 DRB-4Z low NO<sub>x</sub> burners for Unit 1 B&W boiler, 24 DRB-XCL low NO<sub>x</sub> burners for Unit 2 Riley boiler<sup>(3)</sup> (believe southeast coast lignite is primary fuel).

Source: B&W’s experience list<sup>(3)</sup>. No NO<sub>x</sub> reduction claims.

Kansas City Power & Light                      Pulverized coal, opposed wall-fired, 600 MW B&W boiler

Hawthorn Unit 5                                      30 burners, 2001 vintage, (Powder River Basin coal)

B&W provided 30 DRB-4Z low NO<sub>x</sub> burners and 11 OFA ports with the new boiler<sup>(3)</sup>.

Source: B&W’s experience list<sup>(3)</sup>. No NO<sub>x</sub> reduction claims.

***LOW NO<sub>x</sub> BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued***  
**Pulverized coal-fired boilers**

New England Power Company (NEPCO)

Salem Harbor Station Pulverized Coal, front wall-fired,  
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)  
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993  
Riley claimed Unit 1 LNBs reduced NO<sub>x</sub> emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2's LNBs achieved 42% NO<sub>x</sub> reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3's LNBs achieved 60% NO<sub>x</sub> reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu<sup>(24)</sup>.

Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list<sup>(24)</sup>.  
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)

Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired  
Units 4, 5, & 6 1952, 1955, 1957 vintage  
50 MWe x 3 Foster Wheeler boilers  
RJM provided (6) Low NO<sub>x</sub> burner modifications per boiler in 1994, 1992, & 1994 respectively; LNBs reduced NO<sub>x</sub> 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu<sup>(17)</sup>.

Source: RJM experience list September 3, 2004<sup>(17)</sup>

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station Pulverized Coal opposed wall-fired  
Units 1 & 2 1964, 1965 vintage eastern bituminous coal  
360 MW (nominal) B&W boilers  
DB Riley (now Babcock Power) CCV type low NO<sub>x</sub> burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NO<sub>x</sub> up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu<sup>(24)</sup>, assumed at full load).

Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list<sup>(24)</sup>.  
(Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3 Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage  
175 MW October 1992 baseline testing started (western bituminous coal)  
Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO<sub>x</sub> replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.

Uncontrolled NO<sub>x</sub> w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO<sub>x</sub> 37% to 0.46 lb/mmBtu<sup>(30)</sup>.  
Source: DOE NETL 2001 Technical paper<sup>(30)</sup>.

***REBURN – GAS, CONVENTIONAL***

**Pulverized coal-fired boilers**

Allegheny Power (formerly West Pennsylvania Power) Pulverized Coal, opposed wall-fired  
Hatfield's Ferry Station cell-burner, 1969 & 1972 vintage  
Units 2 & 3, 600 MW (nominal) each (B&W boilers) eastern bituminous coal  
GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)  
GE-EER Low NO<sub>x</sub> burners, boosted OFA, gas reburn system.

GE-EER claimed to lower NO<sub>x</sub> up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included<sup>(8)</sup>.

GE-EER technical paper shows approx. 35% NO<sub>x</sub> reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel<sup>(31)</sup>.

B&W added 20 OFA ports in 1994 per B&W's experience list. No NO<sub>x</sub> reduction claims.<sup>(3)</sup>

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(31)</sup>. Unit 2 and Unit 3 listed in <sup>(10)</sup>DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Conectiv (formerly Delmarva Power & Light)  
Edgemoor Unit 4  
160 MW CE boiler

Pulverized Coal, Tangentially-fired  
1966 vintage, eastern bituminous coal  
1999 startup

GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.

Vendor claimed to lower NO<sub>x</sub> up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included<sup>(8)</sup>.

GE-EER technical paper shows approx. 32% NO<sub>x</sub> reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NO<sub>x</sub> reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu <sup>(31)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(31)</sup>. Listed in <sup>(10)</sup>DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power)  
Hennepin Unit 1  
71 MW CE boiler

Pulverized Coal, Tangentially-fired  
1966 vintage  
eastern bituminous coal

GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.

DOE Clean Coal demonstration project (included sorbent injection).

Vendor claimed gas reburn w/ OFA lowered NO<sub>x</sub> up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation<sup>(8)</sup>.

GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NO<sub>x</sub> emissions<sup>(11)</sup>.

Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NO<sub>x</sub> by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel<sup>(11)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(11)</sup>; DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

(Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

AES (formerly New York State Gas & Electric (NYSEG)

Greenidge #6 (NY)  
100 MW CE boiler

Pulverized Coal, Tangentially-fired,  
GE-EER Conventional Gas Reburn, 1996 startup

1953 vintage

Vendor claimed to lower NO<sub>x</sub> 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn<sup>(8)</sup>.

GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NO<sub>x</sub> emissions around 0.23 lb/mmBtu<sup>(11)</sup>.

EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NO<sub>x</sub> by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating)<sup>(10)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(11)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

### ***REBURN – GAS, CONVENTIONAL continued***

#### **Pulverized coal-fired boilers**

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station                      Pulverized Coal      opposed wall-fired B&W boilers

Units 1 & 2                                      1964, 1965 vintage    eastern bituminous coal

360 MW (nominal)                          GE-EER Gas Reburn, 2000 startup

Vendor claimed to lower NO<sub>x</sub> up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included<sup>(8)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>. Listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3                                      Pulverized coal, wall-fired, 1962 vintage

175 MW B&W boiler                              western bituminous coal

DOE Clean Coal demonstration project      November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995.

Existing boiler with 16 burners was retrofitted with low NO<sub>x</sub> burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.

Vendor claimed to lower NO<sub>x</sub> up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation<sup>(8)</sup>.

GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NO<sub>x</sub> emissions<sup>(11)</sup>.

A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO<sub>x</sub> emissions with low NO<sub>x</sub> burners alone (37% reduction), further reduced NO<sub>x</sub> by 44% with 12.5 percent reburn fuel<sup>(10)</sup>.

A 2001 DOE-NETL technical paper claimed a NO<sub>x</sub> reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NO<sub>x</sub> reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input.<sup>(30)</sup>

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(11)</sup>; DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>; DOE-NETL 2001 Technical paper<sup>(30)</sup>; also in DOE 1999 Topical Report Number 14<sup>(14)</sup>.

### ***REBURN – OIL, CONVENTIONAL***

#### **Pulverized coal-fired boilers**

Dynegy (formerly Illinois Power)

Pulverized Coal, Tangentially-fired

Hennepin Unit 1

1966 vintage, eastern bituminous coal

71 MW

CE boiler                                      1997 startup

GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NO<sub>x</sub> up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included<sup>(8)</sup>.

GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn<sup>(11)</sup>.

Source: Sept. 2005 GE-EER experience list<sup>(8)</sup>; GE-EER 2004 Technical paper<sup>(11)</sup>. Orimulsion not mentioned in DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.  
(Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power  
Coleson Cove, Bunker C/Orimulsion-fired, opposed-wall  
St. John, New Brunswick, Canada  
3x 350 MW B&W Boilers  
Sixteen new low-NO<sub>x</sub> oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added<sup>(12)</sup>.  
Another technical paper showed this reburn system lowered NO<sub>x</sub> by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input<sup>(10)</sup>.  
Source: B&W 2004 Technical Paper<sup>(12)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

Georgia Power Pulverized Coal, Tangentially-fired  
Scherer Unit 1 1982 vintage  
887 MW CE boiler 2000 oil reburn startup  
GE-EER Oil Reburn system, claimed to lower NO<sub>x</sub> from baseline of 0.36 lb/mmBtu.  
GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included<sup>(11)</sup>.  
Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO<sub>x</sub> emissions 33% from 0.36 to 0.24 lb/mmBtu; GE-EER 2004 Technical paper<sup>(31)</sup>.  
Not listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

### ***REBURN – COAL, MICRONIZED, CONVENTIONAL***

#### **Pulverized coal-fired boilers**

AES (formerly New York State Electric and Gas Milliken Station Unit 1)  
Cayuga tangentially-fired, pulverized coal, 1956 vintage  
148 MWe, CE boiler eastern bituminous coal  
GE-EER micronized coal reburn system 1996 startup (still operating)  
US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NO<sub>x</sub> with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input<sup>(10)</sup>.  
Not listed in GE-EER's experience list nor in their 2004 technical paper.  
Source: DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

E. ON US Holdings (formerly Louisville Gas and Electric)  
R.D. Green Station Units 1 & 2 (KY) wall-fired, pulverized coal, vintage unknown  
293 MWe, 2 boilers eastern bituminous coal  
GE-EER coal reburn system Startup dates: 2003 & 2002, respectively  
Vendor claimed to lower NO<sub>x</sub> up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation<sup>(8)</sup>.  
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NO<sub>x</sub> lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input<sup>(10)</sup>).  
Another technical paper showed baseline NO<sub>x</sub> with existing low-NO<sub>x</sub> burners was 0.45 lb/mmBtu, and reduced NO<sub>x</sub> emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NO<sub>x</sub> emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation<sup>32</sup>.

Source: Sept. 2005 GE Energy (formerly GE-EER) experience list<sup>(8)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>; March 2004 Modern Power Systems issue article<sup>(32)</sup>.

***REBURN – COAL, MICRONIZED, CONVENTIONAL continued***

**Pulverized coal-fired boilers**

Cheng Loong (not in United States)

Unit #1, 250 MWe wall-fired, bituminous pulverized coal, vintage & mfr unknown  
GE-EER coal reburn system 2000 Startup (still operating)

Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel<sup>(8)</sup>.

Source: Sept. 2005 GE Energy (formerly GE-EER) experience list<sup>(8)</sup>; Listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

***REBURN – GAS, CONVENTIONAL w SNCR***

**Pulverized coal-fired boilers**

NRG Somerset Pulverized Coal, Tangentially-fired, vintage unknown  
Unit 6 Boiler 8 (NY) GE-EER Conventional Gas Reburn,  
120 MW CE boiler Fuel Tech SNCR, 2003 startup

Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%<sup>(32)</sup>.

Source: Sept. 2005 GE Energy experience list<sup>(8)</sup>; March 2004 Modern Power Systems issue<sup>(32)</sup>.

***REBURN – FUEL LEAN GAS REBURN (FLGR)***

**Pulverized coal-fired boilers**

Duke Power Company tangentially-fired, pulverized coal  
Riverbend Unit 7 eastern bituminous coal 1954 vintage  
140 MWe, CE boiler 1998 FLGR startup, gas reburn decommissioned since then

Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).

Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O<sub>2</sub>.<sup>(33)</sup>

Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel<sup>(32)</sup>.

EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input<sup>(10)</sup>.

Source: ESA, GRI, NGB 1998 Technical paper<sup>(33)</sup>; GE Energy 2004 Technical paper<sup>(32)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

Wisconsin Electric Power Company (WEPCO)

Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal  
620 MWg 1980 vintage 1999 startup

Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included<sup>(23)</sup>.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>. Also listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.  
(Also see FLGR + SNCR installation summaries for pulverized coal boilers).

***REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)***

**Pulverized coal-fired boilers**

Carolina Power & Light (Progress Energy)

Asheville Unit 1 Pulverized Coal, front wall fired

200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup

Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NO<sub>x</sub> reduction from baseline<sup>(19)</sup> of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip<sup>(23)</sup>. Low NO<sub>x</sub> burners were previously retrofitted in 1997 without separated overfire air<sup>(26)</sup>. This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NO<sub>x</sub> NSR not stated.

EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NO<sub>x</sub> by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating<sup>(10)</sup>.

Another technical paper showed 52% NO<sub>x</sub> reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH<sub>3</sub> slip of 3 ppm. FLGR alone achieved 23% NO<sub>x</sub> reduction with 6% reburn fuel and < 400 ppm CO at full load.<sup>(26)</sup>

Source: Fuel Tech experience list 1/28/05<sup>(23)</sup>; ICAC SNCR 2000 White Paper<sup>(19)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>; CP&L and Fuel Tech 2001 Technical paper<sup>(26)</sup>.

(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage

660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup

Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NO<sub>x</sub> reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip<sup>(19)</sup>. This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NO<sub>x</sub> NSR not stated.

EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NO<sub>x</sub> by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating<sup>(10)</sup>.

Source: Fuel Tech experience list 1/28/05<sup>(23)</sup>; ICAC SNCR 2000 White Paper<sup>(19)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired

Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal

Furnace #11 & #12 1960 vintage May 1999 startup

Furnace #21 & 22 1961 vintage May 1999 startup

Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NO<sub>x</sub> reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip<sup>(19)</sup>. This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NO<sub>x</sub> starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors<sup>(34)</sup>. Urea-to-NO<sub>x</sub> NSR not stated, goal was NSR < 1.25.

{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}

EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NO<sub>x</sub> by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating<sup>(10)</sup>.

Source: Fuel Tech experience list 1/28/05<sup>(23)</sup>, ICAC SNCR 2000 White Paper<sup>(19)</sup>; PSE&G, FT and ESA 2000 Technical paper<sup>(34)</sup>; DOE-NETL Scorecard on Reburning 6/1/2004 (2004 Reburn Conference).<sup>(10)</sup>

### ***REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued***

#### **Pulverized coal-fired boilers**

Wisconsin Electric Power Company (WEPCO)

Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal

620 MWg 1980 vintage 1999 startup

Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NO<sub>x</sub> reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip<sup>(19)</sup>. This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.

EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NO<sub>x</sub> by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating<sup>(5)</sup>.

Source: Fuel Tech experience list 1/28/05<sup>(23)</sup>, ICAC SNCR 2000 White Paper<sup>(19)</sup> ;

DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)<sup>(10)</sup>.

### ***SELECTIVE NON-CATALYTIC REDUCTION***

#### **Pulverized coal-fired boilers**

American Electric Power (AEP) Pulverized Coal, cell-burner, opposed wall-fired B&W boiler

Cardinal Unit 1 1967 vintage; Low NO<sub>x</sub> burners installed in October 1998

600 MW (nominal) Brilliant, Ohio

Fuel Tech urea-based SNCR installed in October 1998.

Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBS + SNCR w/ 5 ppm NH<sub>3</sub> slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu<sup>(24)</sup>) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO<sub>x</sub> 31% below LNBS alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip<sup>(25)</sup>, burning eastern bituminous coal. Urea-to-NO<sub>x</sub> NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>; ICAC SNCR 2000 White Paper<sup>(19)</sup>, 2000 Fuel Tech technical paper<sup>(25)</sup>, Riley Power (Babcock Power Inc.) experience list 8/16/04<sup>(24)</sup>.

Carolina Power & Light (Progress Energy)

Asheville Unit 1 Pulverized Coal, front wall fired

200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 SNCR startup

Fuel Tech commercial SNCR installation claimed 25% NO<sub>x</sub> reduction from low-NO<sub>x</sub> burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone)<sup>(23)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.

(Also see FLGR + SNCR installation summaries for pulverized coal boilers).

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>.

Carolina Power & Light (Progress Energy)

Pulverized Coal, Tangentially-fired

Cape Fear Unit 5

1956 vintage; eastern bituminous coal

154 MW CE boiler

SNCR startup in 2002

Mobotec USA "Rotamix" ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.

CP&L technical paper claimed to lower NO<sub>x</sub> from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH<sub>3</sub> slip following the installation of ROFA in 2000.

Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu<sup>(27)</sup>. Mobotec claimed further NO<sub>x</sub> reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease<sup>(35)</sup>. Ammonia-to-NO<sub>x</sub> NSR not stated. Source: CP&L 2002 Technical paper<sup>(27)</sup>; Mobotec 2003 technical paper<sup>(35)</sup>.

Carolina Power & Light (Progress Energy)                      Pulverized Coal, Tangentially-fired  
Cape Fear Unit 6                      twin-furnace (eight corner), 1958 vintage; eastern bituminous coal  
175 MW CE boiler                      SNCR startup in 2001  
Mobotec USA “Rotamix” ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air (“ROFA”) system at the boiler.  
CP&L technical paper claimed to lower NO<sub>x</sub> from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH<sub>3</sub> slip following the installation of ROFA+SNCR in 2001<sup>(27)</sup>. Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO<sub>x</sub> emission rate of 0.23 lb/mmBtu. Ammonia-to-NO<sub>x</sub> NSR not stated.  
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu. Mobotec claimed further NO<sub>x</sub> reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease<sup>(35)</sup>. Urea-to-NO<sub>x</sub> NSR not stated. Source: CP&L 2002 Technical paper<sup>(27)</sup>; Mobotec 2003 technical paper<sup>(35)</sup>.

Cinergy (formerly Cincinnati G&E)                      Pulverized Coal, Tangentially-fired,  
Miami Fort Unit 6 (Ohio)                      1960 vintage; startup prior to 2000  
163 MW CE boiler  
Fuel Tech urea-based SNCR system, claimed to lower NO<sub>x</sub> by 35% from 0.55 lb/mmBtu baseline<sup>(20)</sup>. (assume eastern bituminous coal). Urea-to-NO<sub>x</sub> NSR not stated. Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>, ICAC SNCR 2000 White Paper<sup>(19)</sup>.

Conectiv (formerly Delmarva Power & Light)  
Edgemoor Unit 3                      Pulverized Coal, Tangentially-fired, 1954 vintage  
84 MW CE boiler                      mid-March 1996 startup; (assume eastern bituminous coal)  
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NO<sub>x</sub> reduction with less than 10 ppm ammonia slip. Urea-to-NO<sub>x</sub> NSR not stated.  
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline<sup>(20)</sup>.  
Source: Hamon experience list (not listed by Fuel Tech)<sup>(36)</sup>; ICAC SNCR 2000 White Paper<sup>(19)</sup>.

Conectiv (formerly Delmarva Power & Light)                      Pulverized Coal  
Indian River Units 3 & 4 (Millsboro, DE)                      Unit 3 is front wall-fired, 1974 vintage  
178MW and 440 MW                      Unit 4 is turbo-fired opposed-wall, 1980 vintage  
B&W, DB Riley boilers                      Spring 2000 startup (eastern bituminous coal)  
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units. HRC claimed 35% NO<sub>x</sub> reduction with less than 5 ppm ammonia slip<sup>(36)</sup>. Urea-to-NO<sub>x</sub> NSR not stated. An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively<sup>(28)</sup>. Another source listed these units as having a pre-control NO<sub>x</sub> baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively<sup>(1)</sup>. Source: Hamon experience list (not listed by Fuel Tech)<sup>(36)</sup>; REI 1999 technical paper<sup>(28)</sup>; US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005<sup>(1)</sup>.

***SELECTIVE NON-CATALYTIC REDUCTION continued***

**Pulverized coal-fired boilers**

Dominion Generation (Virginia E&P Co.) Clover Station, Units 1 & 2 (VA) 2 x 465 MW Urea-based SNCR (Fuel Tech system) Fuel Tech claimed NO <sub>x</sub> reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu) <sup>(23)</sup> . Source: Fuel Tech experience list dated 1/28/2005 <sup>(23)</sup> . Urea-to-NO <sub>x</sub> NSR not stated.	Pulverized Coal, Tangentially-fired ABB/CE boilers, 1995, 1996 vintage (eastern bituminous coal) 1995, 1996 startup (initial commercial)
Dynegy Midwest Generation (formerly Illinois Power) Vermillion Station, Unit 1 82 MW Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA). Mobotec 2004 technical paper claimed to lower NO <sub>x</sub> by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH <sub>3</sub> slip not mentioned. Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu <sup>(29)</sup> . Urea-to-NO <sub>x</sub> NSR not stated. Source: Mobotec 2004 technical paper <sup>(29)</sup> .	Pulverized Coal, Tangentially-fired 1955 vintage CE boiler, bituminous Illinois coal
Eastern Utilities Associates, Montaup Electric Company Somerset Unit 8 (Massachusetts) 112 MW CE boiler Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NO <sub>x</sub> below 0.38 lb/mmBtu (Mass. RACT) <sup>(36)</sup> . Urea-to-NO <sub>x</sub> NSR not stated. Another source listed 28-60% NO <sub>x</sub> reduction from a 0.49-0.89 lb/mmBtu baseline <sup>(19)</sup> . Source: Hamon experience list 4/26/04 <sup>(36)</sup> , Fuel Tech experience list dated 1/28/2005 <sup>(23)</sup> , ICAC SNCR 2000 White Paper <sup>(19)</sup> .	Pulverized Coal, Tangentially-fired 1959 vintage Summer 1995 startup (eastern bituminous coal)
First Energy Eastlake Unit 3 (Ohio) 130 MW CE boiler (w/ division wall) Urea-based SNCR (Fuel Tech system) Fuel Tech claimed to lower NO <sub>x</sub> from 20-32.5% from 0.34-0.40 lb/mmBtu baseline <sup>(23)</sup> . Urea-to-NO <sub>x</sub> NSR not stated. Source: Fuel Tech experience list dated 1/28/2005 <sup>(23)</sup> ; ICAC SNCR 2000 White Paper <sup>(19)</sup> .	Pulverized Coal, Tangentially-fired, 1954 vintage (eastern bituminous coal) SNCR startup prior to 2000
First Energy Sammis Unit 2 (Ohio) 180 MW Foster Wheeler boiler SNCR startup Fall 1999 Urea-based SNCR (Fuel Tech system) Fuel Tech claimed to lower NO <sub>x</sub> from 25-30% from 0.45 lb/mmBtu baseline <sup>(23)</sup> . Urea-to-NO <sub>x</sub> NSR not stated. Source: Fuel Tech experience list dated 1/28/2005 <sup>(23)</sup> , ICAC SNCR 2000 White Paper <sup>(19)</sup> .	Pulverized Coal, wall-fired, 1960 vintage (eastern bituminous coal)
First Energy Sammis Units 6 & 7 (Ohio) 680 MW B&W Universal Pressure boilers Urea-based SNCR (Fuel Tech system)	Pulverized Coal, wall-fired, 1969 & 1971 vintage (eastern bituminous coal) SNCR startup after 1999

Fuel Tech claimed to lower NO<sub>x</sub> from 25% from 0.38 lb/mmBtu baseline<sup>(23)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>.

### ***SELECTIVE NON-CATALYTIC REDUCTION continued***

#### **Pulverized coal-fired boilers**

New England Power Company (NEPCO)

Salem Harbor Station

Units 1, 2 & 3

84 MWe x 2, & 156 MWe B&W boilers

Urea-based SNCR (Fuel Tech system)

Fuel Tech claimed 66% (50-75%) NO<sub>x</sub> reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu<sup>(23)</sup>, (which would lower NO<sub>x</sub> to around 0.34±0.07 lb/mmBtu). Urea-to-NO<sub>x</sub> NSR not stated. {These NO<sub>x</sub> reduction percentages may include impact of low-NO<sub>x</sub> burners}.

Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>, ICAC SNCR 2000 White Paper<sup>(19)</sup>.

(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)

Schiller Units 4, 5, & 6

50 MWe x 3 Foster Wheeler boilers

Urea-based SNCR (Fuel Tech system)

August 1999 startup

RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.

RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO<sub>x</sub> baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction)<sup>(17)</sup>; Urea-to-NO<sub>x</sub> NSR not stated.

Fuel Tech claimed 30% NO<sub>x</sub> reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only<sup>(23)</sup>.

Source: RJM experience list 9/3/04<sup>(17)</sup>, Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>.

Owensboro Municipal Utilities (KY)

Elmer Smith Unit 2

300 MW CE boiler

Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NO<sub>x</sub> reduction<sup>(36)</sup>; (this project is not listed in ICAC SNCR 2000 White Paper<sup>(19)</sup>). Ammonia-to-NO<sub>x</sub> NSR not stated.

Source: Hamon experience list 4/26/04<sup>(36)</sup>.

PECO Energy (formerly Philadelphia Electric Company)

Cromby Unit 1

160 MWe B&W boiler 1954 vintage

RJM installed Fuel Tech urea-based SNCR with low NO<sub>x</sub> burner modifications & OFA in 1999, June 1999 startup.

RJM claimed 29% SNCR NO<sub>x</sub> reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NO<sub>x</sub> burners installed in 1994 + OFA; this reduced NO<sub>x</sub> from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR<sup>(17)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.

Source: RJM experience list 9/3/2004<sup>(17)</sup>; ICAC SNCR 2000 White Paper<sup>(20)</sup>.

***SELECTIVE NON-CATALYTIC REDUCTION continued***

**Pulverized coal-fired boilers**

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)  
Eddystone Units 1 & 2                      Pulverized Coal      Tangentially-fired,                      1954 vintage  
318, 333 MW each CE boilers      1999 SNCR startup, eastern bituminous coal  
Fuel Tech claimed 30% NO<sub>x</sub> reduction from baseline of 0.26 lb/mmBtu<sup>(23)</sup>.  
Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>.

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Hudson Station, Unit 2                      Pulverized Coal, opposed-wall-fired, 1968 vintage  
660 MWe Foster Wheeler boiler eastern bituminous coal                      March 1999 startup  
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NO<sub>x</sub> reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu)<sup>(23)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.  
Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>, also listed in ICAC SNCR 2000 White Paper<sup>(19)</sup>.  
(Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Mercer Station                      (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired  
Unit 1 and Unit 2                      front wall PC, wet-bottom (slagging ash) eastern bituminous coal  
Furnace #11 & #12                      1960 vintage                      April 1999 startup  
Furnace #21 & 22                      1961 vintage                      May 1999 startup  
Fuel Tech urea-based commercial SNCR installation claimed 30-35% NO<sub>x</sub> reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu<sup>(23)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.  
Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>, also listed in ICAC SNCR 2000 White Paper<sup>(19)</sup>.  
(Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Reliant Energy (formerly GPU Genco)                      Pulverized Coal  
(formerly Sithe, formerly Penelec)                      Tangentially-fired  
Seward # 15 (PA)                      mid-1990's SNCR startup  
Units 4 & 5                      eastern bituminous coal  
62 & 156 MW CE boilers                      1950 & 1957 vintage  
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH<sub>3</sub> slip.  
Fuel Tech claimed to lower NO<sub>x</sub> 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline)<sup>(23)</sup>. Boilers have since been demolished and replaced with CFBs. Urea-to-NO<sub>x</sub> NSR not stated.  
Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>, ICAC SNCR 2000 White Paper<sup>(19)</sup>.

Rochester Gas & Electric                      Pulverized Coal, Tangentially-fired  
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage  
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers                      eastern bituminous coal  
Urea-based SNCR (Fuel Tech system)                      SNCR startup prior to 2000  
Vendor claimed to lower NO<sub>x</sub> by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines<sup>(23)</sup>. Urea-to-NO<sub>x</sub> NSR not stated.  
Source: Fuel Tech experience list dated 1/28/2005<sup>(23)</sup>.

***HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)***

**Pulverized coal-fired boilers**

Tennessee Valley Authority (TVA) Kingston Power Station (TN) Unit 9, 200 MWe CE boiler	Pulverized Coal twin-furnace, tangentially-fired, 1955 vintage eastern bituminous coal NOxStar™ startup January 2002
--	--

Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation. Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%<sup>(37)</sup>; boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.

TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" ([http://www.tva.gov/environment/reports/envreports/aer/2003/env\\_compliance.htm](http://www.tva.gov/environment/reports/envreports/aer/2003/env_compliance.htm))  
Source: Mitsui Babcock Technical paper, October 2003<sup>(37)</sup>.

Tennessee Valley Authority (TVA) Colbert Station (AL) Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR	Pulverized Coal, wall-fired 1955 vintage eastern bituminous coal
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First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology. Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling<sup>(38)</sup>; 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.  
Source: Mitsui Babcock 2004 Technical paper<sup>(38)</sup>.

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#### **Appendix A4 - Technical Literature References for U.S. Cyclone NO<sub>x</sub> Reduction Projects Summary:**

<sup>(1)</sup>EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO<sub>x</sub> Presumptive Limits, June 15, 2005, OAR-2002-0076-0445, and EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NO<sub>x</sub> Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at <http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b>

<sup>(2)</sup> RMT 2003 Technical Paper “NO<sub>x</sub> Control In Coal Fired Cyclone Boilers using SmartBurn<sup>SM</sup> Combustion Technology” by Edmundo R. Vásquez, PhD, Alliant Energy Corporate Services, and Hani Gadalla, Keir McQuistan, Felicia Iman and Rodney E. Sears, RMT Inc. presented at 2003 MEGA Powerplant Air Pollution Control Symposium, Washington D.C., May 19-22, 2003.

<sup>(3)</sup> B&W experience list September 18, 2002.

<sup>(4)</sup> REI 2002 Technical Paper “Demonstration of Rich Reagent Injection for NO<sub>x</sub> Control in AmerenUE’s Sioux Unit 1” by Marc A. Cremer and Bradley R. Adams, Reaction Engineering International, David E. Boll, AmerenUE, and David C. O’Connor, Electric Power Research Institute, presented at the US DOE Conference on SCR/SNCR for NO<sub>x</sub> Control, Pittsburgh, PA, May 15-16, 2002; and

<sup>(5)</sup> REI 2003 Technical Paper “Improved Rich Reagent Injection (RRI) Performance For NO<sub>x</sub> Control In Coal Fired Utility Boilers” by Marc A. Cremer and Huafeng D. Wang, Reaction Engineering International, David E. Boll, AmerenUE, Edmund Schindler, RJM Corporation, and Edmundo Vasquez, RMT, Inc., Alliant Energy Corp., presented at 2003 U.S. DOE Conference on SCR and SNCR for NO<sub>x</sub> Control, Pittsburgh, PA, October 29-30, 2003.

<sup>(6)</sup> REI 2004 Technical paper, “Evaluation of Cost Effective Non-SCR Options for NO<sub>x</sub> Control in PRB Fired Cyclone Boilers” by Marc A. Cremer and David H. Wang, and Bradley R. Adams, Reaction Engineering International, David E. Boll and Kenneth B. Stuckmeyer, AmerenUE, presented at the Western Fuels Symposium, 19<sup>th</sup> International Conference on Lignite, Brown, and Subbituminous Coals (formerly Low-Rank Fuels), October 12-14, 2004, Billings, MT.

<sup>(7)</sup> REI 2005 Technical paper “NO<sub>x</sub> Emissions Below 0.15 lb/Mbtu Achieved in a Cyclone-Fired Boiler Using In-Furnace Control”, by M. Cremer, B. Adams, and A. Chiodo, Reaction Engineering International; C. Giesmann, K. Stuckmeyer, and J. Boyle, AmerenUE, presented at the Powergen International 2005 conference, December 6-8, 2005, Las Vegas, Nevada

<sup>(8)</sup> GE Energy (formerly GE-EER) experience list September 29, 2005.

<sup>(9)</sup> Burns & McDonnell internal database for OFA NO<sub>x</sub> reduction projects.

<sup>(10)</sup> DOE-NETL 2004 Technical Paper “Reburning Projects in the Department of Energy’s Clean Coal Technology Demonstration Program”, by Al Mann and Tom Ruppel, Parsons Corporation, and Tom Sarkus, National Energy Technical Laboratory, presented at the 2004 DOE-NETL Conference on Reburning for NO<sub>x</sub> Control, Morgantown, WV, May 18, 2004. A reburn-related document (an updated version of a poster from the May 18 Conference) is titled “Scorecard on Reburning 6/1/2004” by Al Mann and Tom Ruppel, Parsons Corporation, available on-line at: <http://www.netl.doe.gov/publications/proceedings/04/NOx/posters/Reburning%20Scorecard.pdf>

- <sup>(11)</sup> GE Energy 2004 Technical paper “Reburn Technology Application Guidelines”, by David Moyeda, GE Energy, presented at the 2004 DOE-NETL Conference on Reburning for NO<sub>x</sub> Control”, Morgantown, WV, May 18, 2004.
- <sup>(12)</sup> B&W 2004 Technical Paper “B&W’s Reburning Experience”, by H. Farzan, G. Maringo, A. Yagiela, A. Kokkinos, Babcock & Wilcox, Co., presented at the 2004 DOE-NETL Conference on Reburning for NO<sub>x</sub> Control, Morgantown, WV, May 18, 2004. (This data is a duplicate of a more detailed technical paper published earlier, “B&W’s Advance on Cyclone NO<sub>x</sub> Control Via Fuel and Air Staging Technologies”, by H. Farzan, G. Maringo, D.W. Johnson, and D.W. Wong, Babcock & Wilcox, Co., C.T. Beard, Eastman Kodak Company, and S.E. Brewster, Tennessee Valley Authority, presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August 16-20, 1999).
- <sup>(13)</sup> B&W case history “B&W Cyclone Reburn Leads to NO<sub>x</sub> Reduction, Wisconsin Power & Light Co. Nelson Dewey Unit No. 2” (from website <http://www.babcock.com/pgg/ps/casehistories.html>, dated 1997).
- <sup>(14)</sup> DOE Topical Report Number 14 “Reburning Technologies for the Control Of Nitrogen Oxides Emissions from Coal-Fired Boilers”, conducted under separate cooperative agreements between the U.S. Department of Energy, the Babcock & Wilcox Company, Energy and Environmental Research Corporation, and New York State Electric & Gas Corporation, May 1999.
- <sup>(15)</sup> Technical Paper “Predictions of FLGR at Commonwealth Edison’s Joliet Unit 6” by NGB Technologies, posted on their website: [http://www.ngbtech.com/subpages/proj/joliet\\_results.html](http://www.ngbtech.com/subpages/proj/joliet_results.html)
- <sup>(16)</sup> REI 2001 Technical paper “CFD Evaluation of Fuel Lean Gas Reburn (FLGR™) and Selective Non-Catalytic Reduction in Owensboro Municipal Utilities’ Elmer Smith Station”, by David H. Wang, Marc A. Cremer, and Bradley R. Adams, Reaction Engineering International, K.D. Frizzell, Owensboro Municipal Utilities, and G.C. Dusatko, Sargent & Lundy, 2001 US EPA/DOE MEGA Symposium on SCR and SNCRs, Chicago, IL, August 20-23, 2001.
- <sup>(17)</sup> RJM experience list September 3, 2004.
- <sup>(18)</sup> “Design and Demonstration of Rich Reagent Injections (RRI) Performance For NO<sub>x</sub> Reduction at Connectiv’s B.L. England Station” by Cremer, Marc A. and Adams, Bradley R. (Reaction Engineering International); O’Connor, David C. (Electric Power Research Institute); Bhamidipati, Venkata (Connectiv B.L. England Station), and Broderick, R. Gifford (RJM Corporation), presented at the 2001 US EPA/DOE/EPRI MEGA Symposium on SCR and SNCRs, Chicago, IL, August 20-23, 2001. (available from REI’s internet website [http://www.reaction-eng.com/downloads/rri\\_mega.pdf](http://www.reaction-eng.com/downloads/rri_mega.pdf))
- <sup>(19)</sup> SNCR “White Paper”, Institute of Clean Air Companies, Inc. (ICAC), SNCR Committee, May 2000, Fuel Tech website <http://www.fueltechnv.com/pdf/TPP-534.pdf>
- <sup>(20)</sup> Technical paper “Operating Experience and Future Challenges With SCR Applications”, by Gerd Beckmann and Clayton A. Erickson, Babcock Borsig Power, Inc., presented at Power-Gen International 2000, November 14, 2000, Orlando, FL.
- <sup>(21)</sup> DOE NETL Technical paper “Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR)”, Clean Coal Technology Topical Report Number 9, July 1997, posted on their website: <http://www.netl.doe.gov/publications/others/topicals/topical9.pdf>.

(22) SCR White Paper, Institute of Clean Air Companies, Inc. (ICAC), SCR Committee, November 1997, [http://www.ammoniapro.com/Ammonia%20Library/NOx%20Reduction/Institute%20of%20Clean%20Air%20Co\\_SCR.pdf](http://www.ammoniapro.com/Ammonia%20Library/NOx%20Reduction/Institute%20of%20Clean%20Air%20Co_SCR.pdf), linked to R.M. Technologies website <http://www.rmtech.net/articals.htm>

(23) Fuel Tech experience list dated 1/28/2005.

(24) Babcock Power Inc (DB Riley Power, also Babcock Borsig Power) 8/16/04 experience list.

(25) Technical paper “Cardinal Unit 1 Large Scale Selective Non-Catalytic Reduction Demonstration Project”, by Patrick M. Malone, American Electric Power Service Corp, and Dr. William H. Sun, Fuel Tech, presented at the ICAC Forum 2000, March 23-24, 2000, Rosslyn, VA.

(26) 2001 Technical Paper “Application of Fuel Lean Gas Reburn With SNCR On A 198 MW Coal-Fired Utility Boiler” by David Killen, Carolina Power & Light Co., John M. Boyle and John H. O’Leary, Fuel Tech Inc., presented at the 2001 US EPA/DOE/EPRI MEGA Symposium on SCR and SNCRs, Chicago, IL, August 20-23, 2001.

(27) CP&L 2002 Technical Paper “Rotating Opposed Fire Air (ROFA) and SNCR“, by Mark Shilling and Gary Tonamaker, Carolina Power & Light Co., presented at the 2002 DOE-NETL Conference on Unburned Carbon on Utility Flyash, May 14, 2002, , Pittsburgh, PA.

(28) REI 1999 Technical Paper “CFD Modeling of SNCR Performance in Conectiv’s Indian River Units 3 and 4”, by M. Cremer and M. Heap, Reaction Engineering International, M. Zoccola, Conectiv, and V. Ciarlante, Hamon-Research Cottrell, presented at DOE Conference on SCR and SNCR for NO<sub>x</sub> Control, May 20-21, 1999, Pittsburgh, PA.

(29) Mobotec 2004 Technical Paper “SCR Levels of NO<sub>x</sub> Reduction with ROFA and Rotamix (SNCR) at Dynegy’s Vermillion Power Station“, by Kristopher A. Coombs, Sr., Dynegy Midwest Generation, and Jay S. Crilley, Mark Shilling, and Edwin Haddad, Mobotec USA, Inc., presented at the 2004 Stack Emissions Symposium, Clearwater Beach, FL, July 28-30, 2004.

(30) DOE NETL Technical paper “Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler A DOE Assessment”, dated February 2001. DOE/NETL-2001/1143, posted on their website: <http://www.netl.doe.gov/cctc/resources/pdfs/eerco/GRLNBPPA.pdf>.

(31) GE Energy (formerly GE-EER) 2004 Technical paper “Experience with Reburn for NO<sub>x</sub> Emissions Control”, by Don Engelhardt, Roy Payne, David Moyeda, Blair Folsom, GE Energy, presented at the 2004 DOE-NETL Conference on Reburning for NO<sub>x</sub> Control, Morgantown, WV, May 18, 2004.

(32) GE Energy (formerly GE-EER) 2004 Technical paper “Power plant mosaics: paving the way to 0.11 lb/MMBtu without SCR”, by Blair Folsom, GE Energy, published in the March 2004 issue of Modern Power Systems.

(33) NGB Technical paper “Fuel Lean Gas Reburn (FLGR™) Technology for Achieving NO<sub>x</sub> Emissions Compliance: Application to a Tangentially-Fired Boiler”, by Richard D. Frederiksen, Werner J.A. Dahm, and Gretar Tryggvason, NGB Technologies, Inc., Bernard P. Breen, Roger Glickert, and Joseph A. Urich, Energy Systems Associates, and John M. Pratapas and Robert V. Serauskas, Gas Research Institute (GRI), presented at the 1998 Joint American/Japanese Flame Research Committee International Symposium Environmental Control of Combustion Processes: Innovative Technology Towards the 21<sup>st</sup> Century, Maui, Hawaii, October 11-15, 1998.

<sup>(34)</sup> Technical paper “First Commercial Installation of Amine Enhanced Fuel Lean Gas Reburn On Units 1 and 2 at Public Service Electric & Gas Mercer Station”, by Andrew F. Gomez, Public Service Electric & Gas Company (PSE&G) Mercer Generating Station, Alexander S. Dainoff and John H. O’Leary, Fuel Tech, Inc., and Robert Schrecengost, Energy Systems Associates, presented at the 2000 DOE-NETL Conference on SCR and SNCR for NO<sub>x</sub> Control, Pittsburgh, PA, May 17-18, 2000.

<sup>(35)</sup> Mobotec 2003 Technical Paper “Injection of Urea through the Rotamix System to Obtain Improved NO<sub>x</sub> Reduction“, by John Ralston and Edwin Haddad, Mobotec USA, Inc., presented at the 2003 U.S. DOE Conference on SCR and SNCR for NO<sub>x</sub> Control, Pittsburgh, PA, October 29-30, 2003.

<sup>(36)</sup> Hamon SNCR experience list April 26, 2004.

<sup>(37)</sup> Mitsui Babcock 2003 Technical paper, “NO<sub>x</sub>Star™ Plant Demonstration, October 2003”, by K.W. Morris and G. Hesselman, Mitsui Babcock (US), presented at the 2003 U.S. DOE Conference on SCR and SNCR for NO<sub>x</sub> Control, Pittsburgh, PA, October 29-30, 2003.

<sup>(38)</sup> Mitsui Babcock 2004 Technical paper, “Installation of NO<sub>x</sub>Star™ System at TVA Colbert”, by Keith W. Morris, Mitsui Babcock (US), presented at the Coal-Gen 2004 Conference, July 28-30, 2004, Overland Park, KS.

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**APPENDIX A5 - EERC Report – Ash Impacts on SCR Catalyst Performance**

# **ASH IMPACTS ON SCR CATALYST PERFORMANCE**

*Prepared by:*

Steven A. Benson, Ph.D.

Energy & Environmental Research Center  
University of North Dakota  
PO Box 9018  
Grand Forks, ND 58202-9018

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## ASH IMPACTS ON SCR CATALYST PERFORMANCE

### EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO<sub>x</sub> reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NO<sub>x</sub> emissions at MRV Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRV plant technically infeasible for NO<sub>x</sub> control.

#### ➤ Blinding of Catalyst Pores by High Sodium Compounds

- X High levels of alkali and alkaline-earth elements present in the coal fired at the MRV plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.
- Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a result of cyclone firing.
- Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
- The sulfate reactions are more severe at MRV because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.
- The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.
- Deposit carryover, or “popcorn ash,” plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.
- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

➤ Cold Side SCR Installation

- High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.
- These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.
- Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO<sub>3</sub> from SO<sub>2</sub>. The presence of SO<sub>3</sub> significantly enhances the formation of the pyrosulfates.

# ASH IMPACTS ON SCR CATALYST PERFORMANCE

## INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO<sub>x</sub> burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

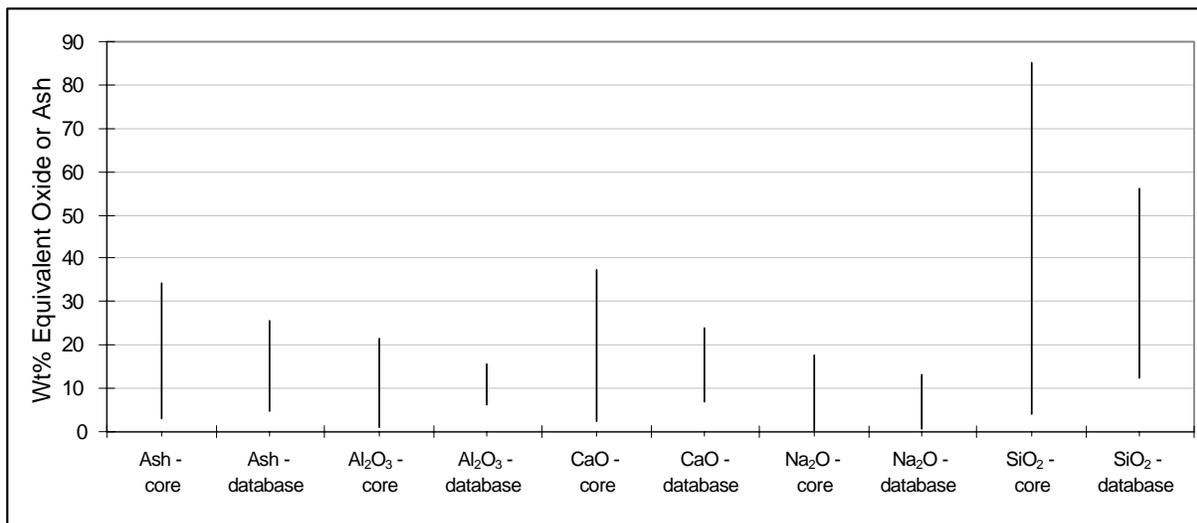
## **INORGANIC COMPOSITION OF LOW-RANK COALS**

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).



**Figure 1.** Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

## INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15  $\mu\text{m}$ , depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, “fine limit,” assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2  $\mu\text{m}$ . The second, “total coalescence,” assumes one fly ash particle forms per coal particle. The third, “partial coalescence,” suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz ( $\text{SiO}_2$ ) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to  $\text{FeO}$ ,  $\text{Fe}_3\text{O}_4$ , and  $\text{Fe}_2\text{O}_3$  during combustion.

## **ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS**

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10  $\mu\text{m}$  that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10  $\mu\text{m}$  that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit “slag”. Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

## **ASH-RELATED EXPERIENCES AT MRY FACILITY**

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

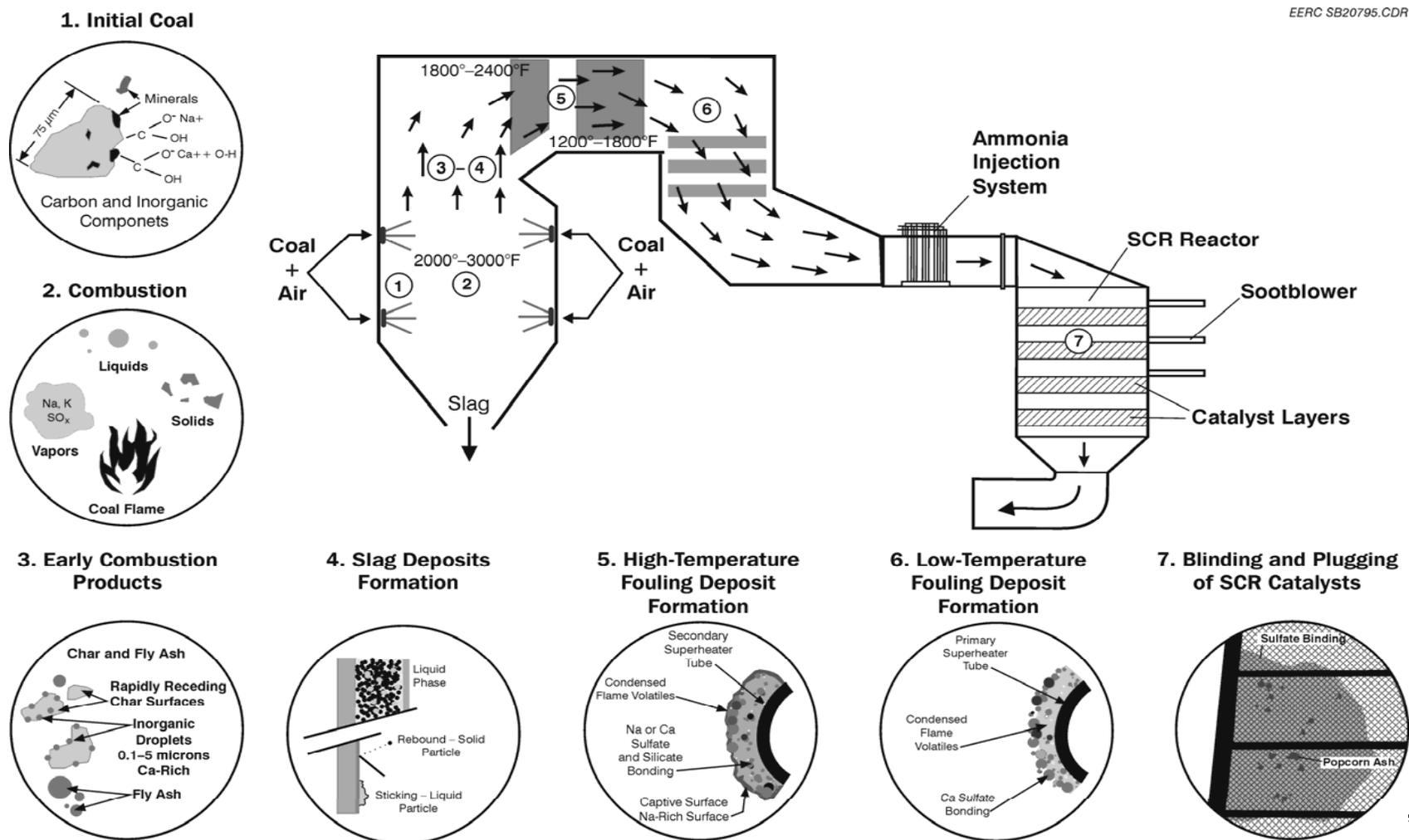


Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

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## History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.
- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.
- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

## Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO<sub>2</sub> and SO<sub>3</sub> to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

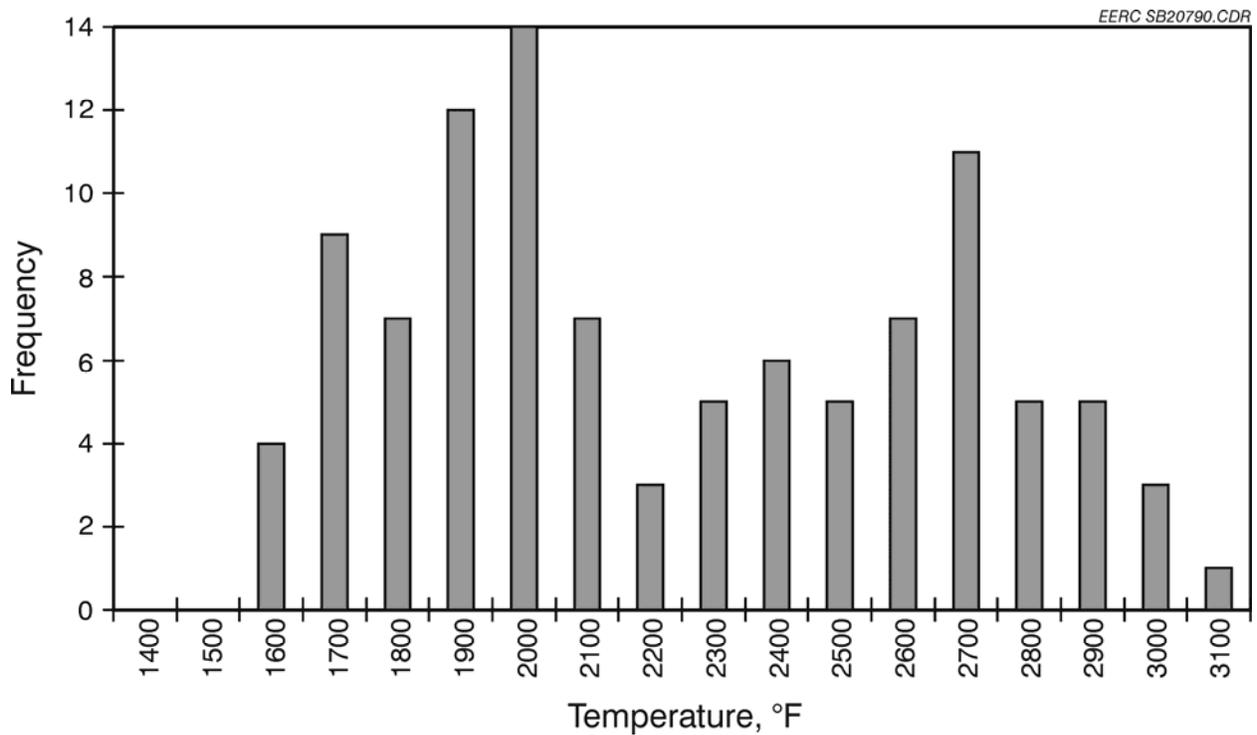
During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

**Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples**

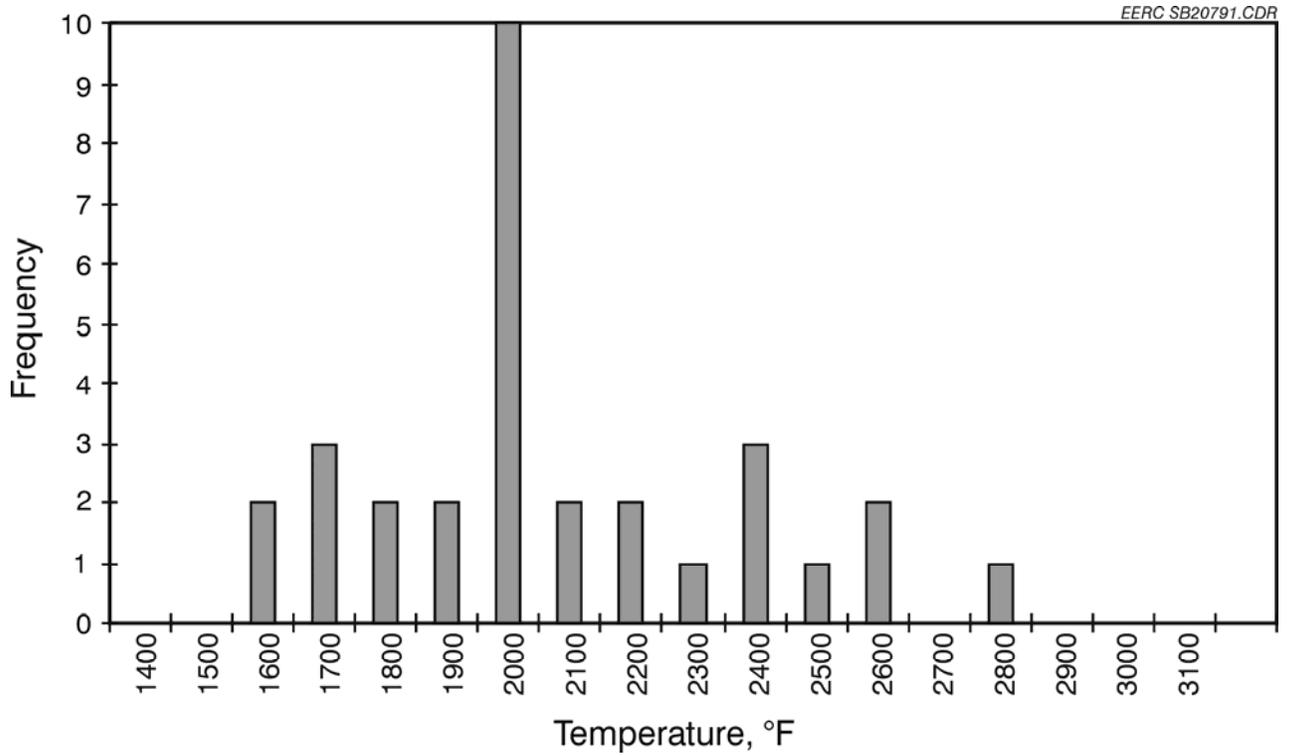
BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na <sub>2</sub> O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al <sub>2</sub> O <sub>3</sub>		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO <sub>2</sub>		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P <sub>2</sub> O <sub>5</sub>		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO <sub>3</sub>		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K <sub>2</sub> O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO <sub>2</sub>		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28
												Continued . .
MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe <sub>2</sub> O <sub>3</sub>		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index												
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

**Table 2. Advanced Index Values for Other Coals (12)**

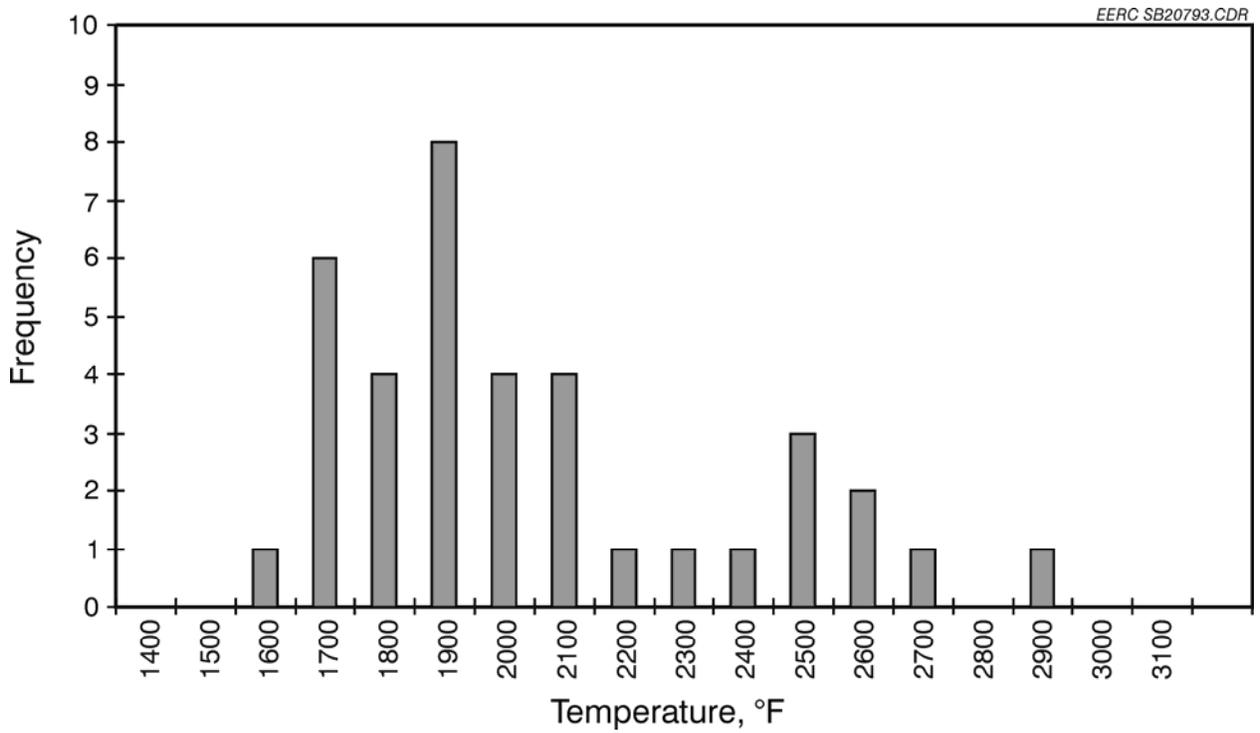
Advanced Indices	Lignite		Bituminous	Bituminous
	North Dakota	Powder River Basin	Illinois	Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96



**Figure 3.** T<sub>250</sub> frequency distribution for all Coal Quality Management System (CQMS) data, °F.



**Figure 4.** T<sub>250</sub> distribution for HA seam coal.



**Figure 5.** T<sub>250</sub> distribution for HB seam coal.

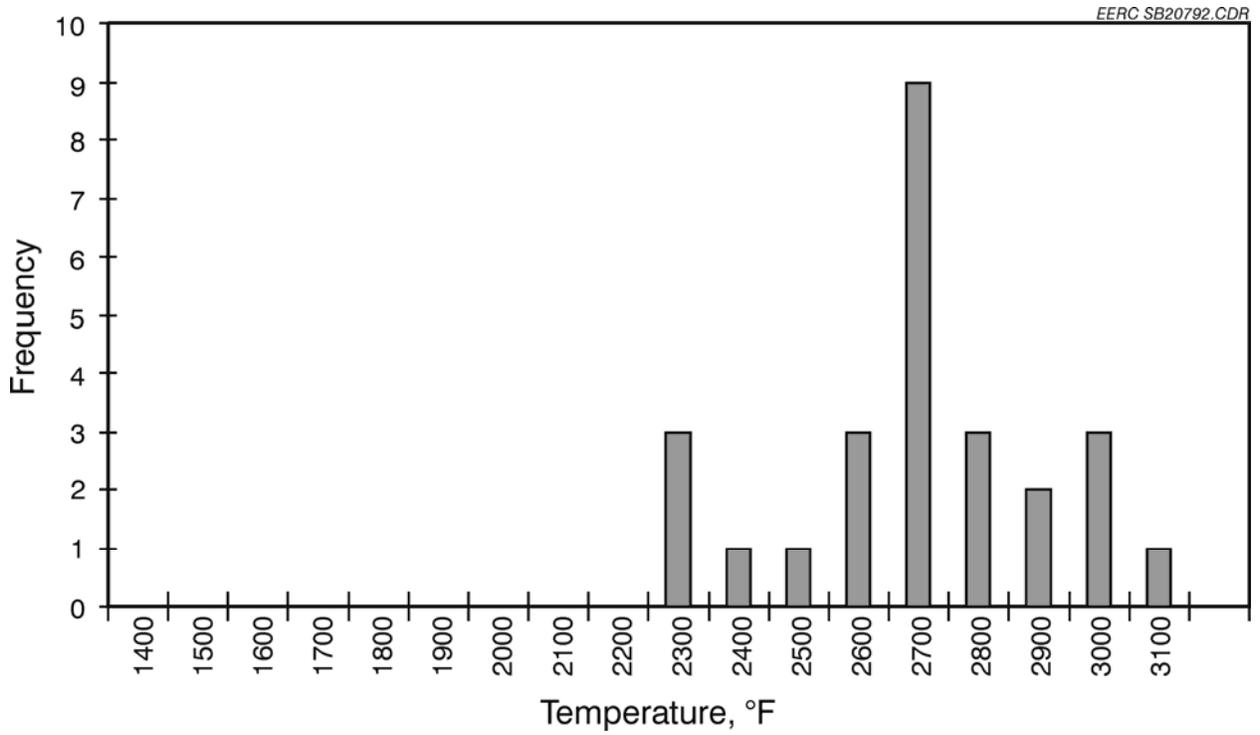


Figure 6.  $T_{250}$  distribution for KC seam coal.

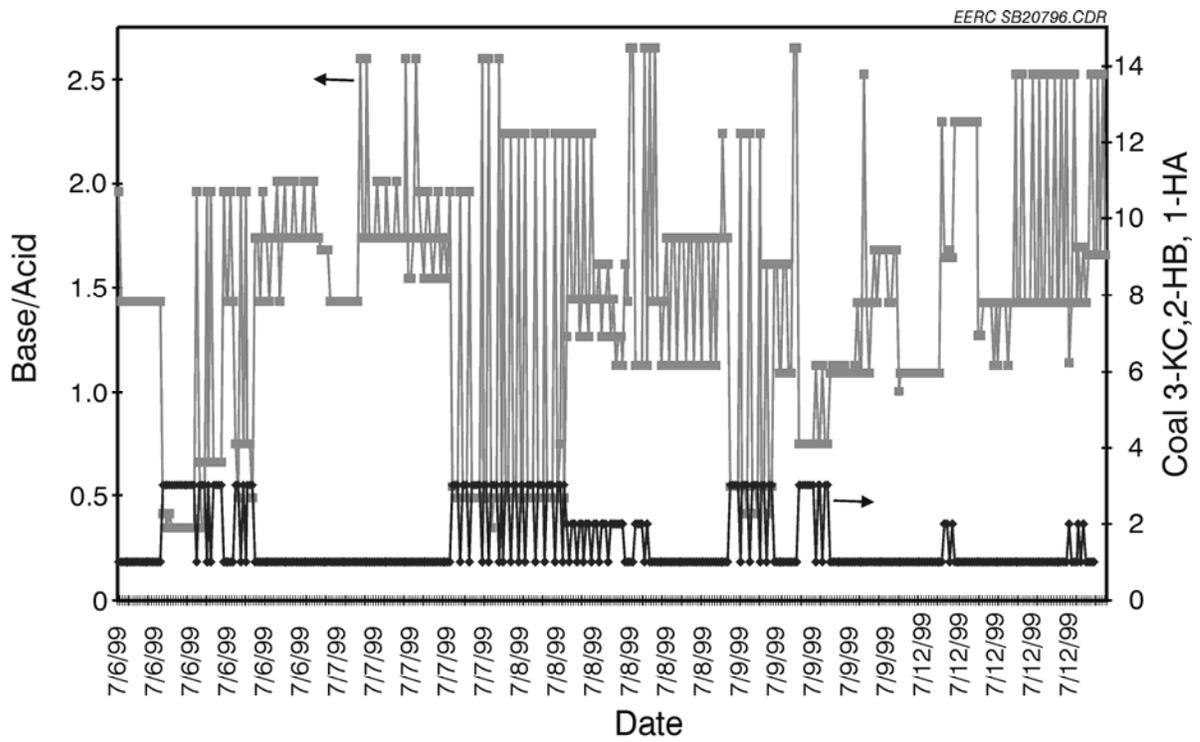


Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

## **ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE**

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.
- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO<sub>3</sub> on the catalyst, resulting in plugging of pores and a decrease in the ability of NH<sub>3</sub> to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO<sub>2</sub> to N<sub>2</sub> and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5- $\mu\text{m}$ -size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5- $\mu\text{m}$  ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

### **Full-Scale Slipstream Testing**

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5  $\mu\text{m}$ ) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for  $\text{NO}_x$  at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop

across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- X Gas temperature: ~700°–800°F
- X Gas flow rate: 400–500 acfm
- X Approach velocity range: 5.0–5.5 m/sec
- X Ammonia injection rate: 0.5:1 with NO<sub>x</sub> level
- X Tempering air for fan: ~ 50–200 scfm
- X Catalyst dP: 0.5–1.0 inches water column
- X Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO<sub>2</sub>) carrier impregnated with the active components vanadium pentoxide (V<sub>2</sub>O<sub>5</sub>) and tungsten trioxide (WO<sub>3</sub>). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO<sub>2</sub>-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable

accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5- $\mu\text{m}$  ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with  $\text{SO}_2/\text{SO}_3$  in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low  $\text{NO}_x$  conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over 0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop

across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

### **SCR Ash Deposit Characterization**

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure 15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

### **SCR Deposit Formation Mechanisms**

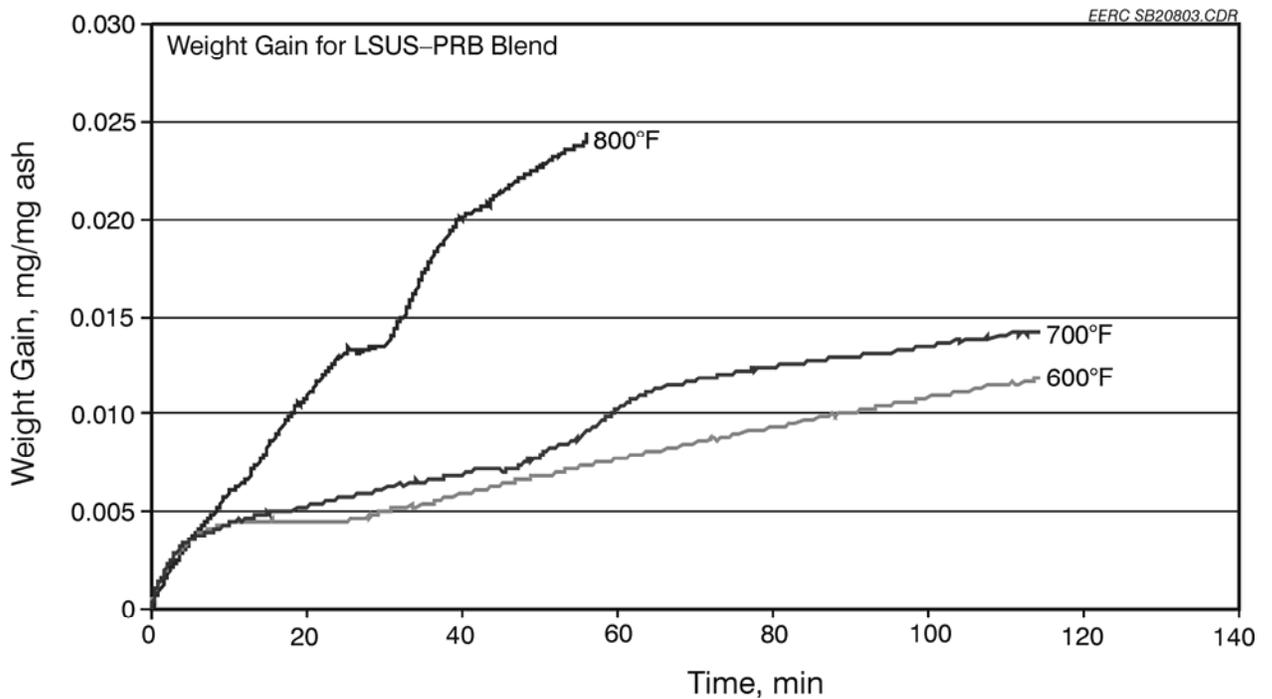
The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with  $\text{SO}_2/\text{SO}_3$  to form sulfates. The formation of  $\text{SO}_3$  from  $\text{SO}_2$  is catalyzed by the SCR; this, in turn, increases the reaction rate of  $\text{SO}_3$  to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with  $\text{CO}_2$  to form carbonates. XRD analysis identified  $\text{CaSO}_4$  as a major phase and  $\text{Ca}_3\text{Mg}(\text{SiO}_4)_2$  and  $\text{CaCO}_3$  as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

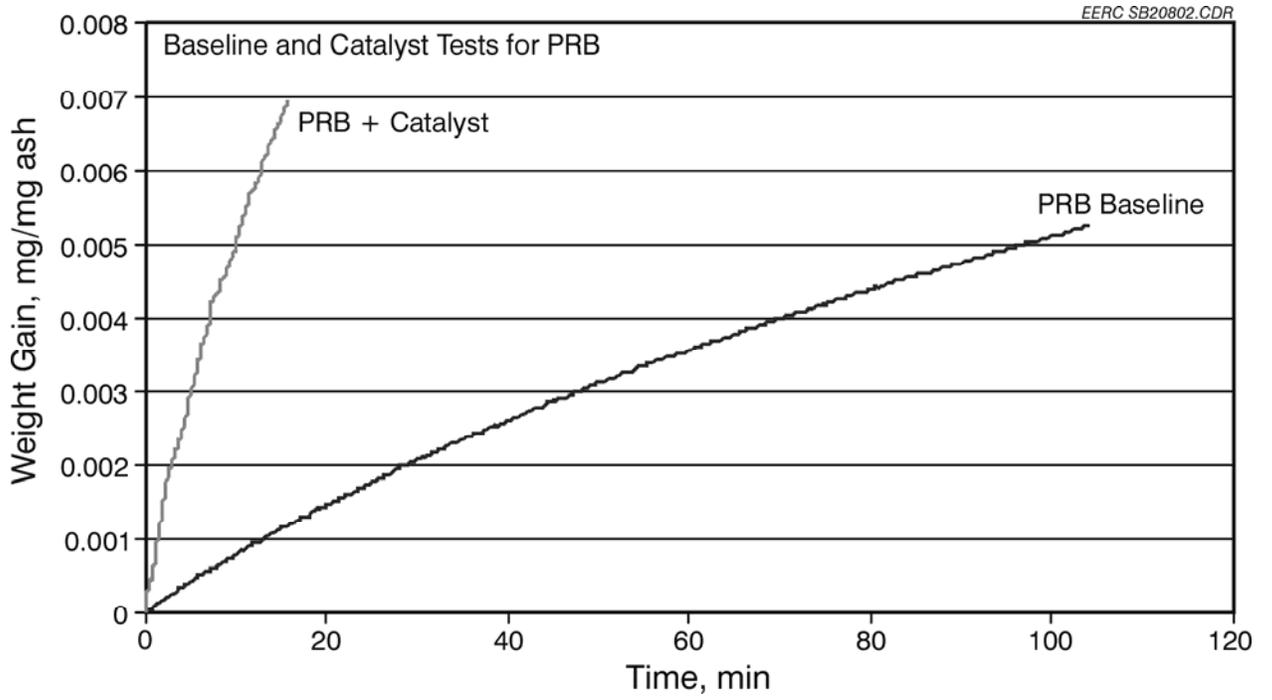
During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the  $<5\text{-}\mu\text{m}$  size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst

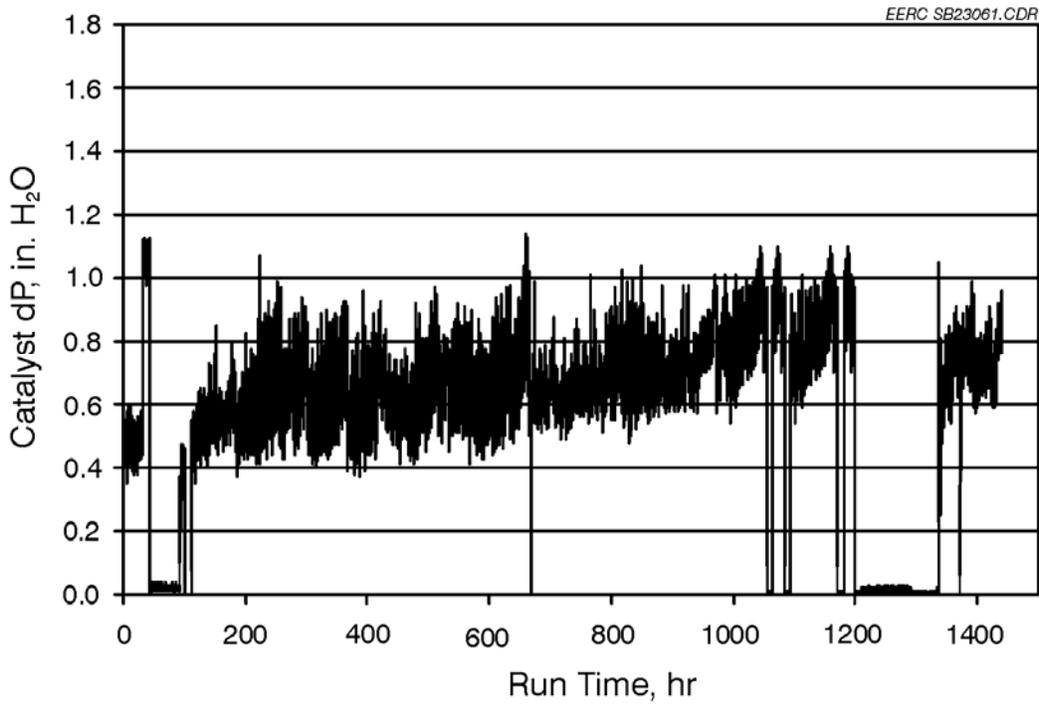
include firing a coal that produces significant levels of <5- $\mu\text{m}$ -sized particles. The particles are transported into the pores of the catalyst and subsequently react with  $\text{SO}_3$  to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of  $\text{SO}_3$  and thereby increases the rate of sulfation (24, 25). The sulfation of  $\text{CaO}$  increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as  $535^\circ\text{F}$  in coal-fired power systems.



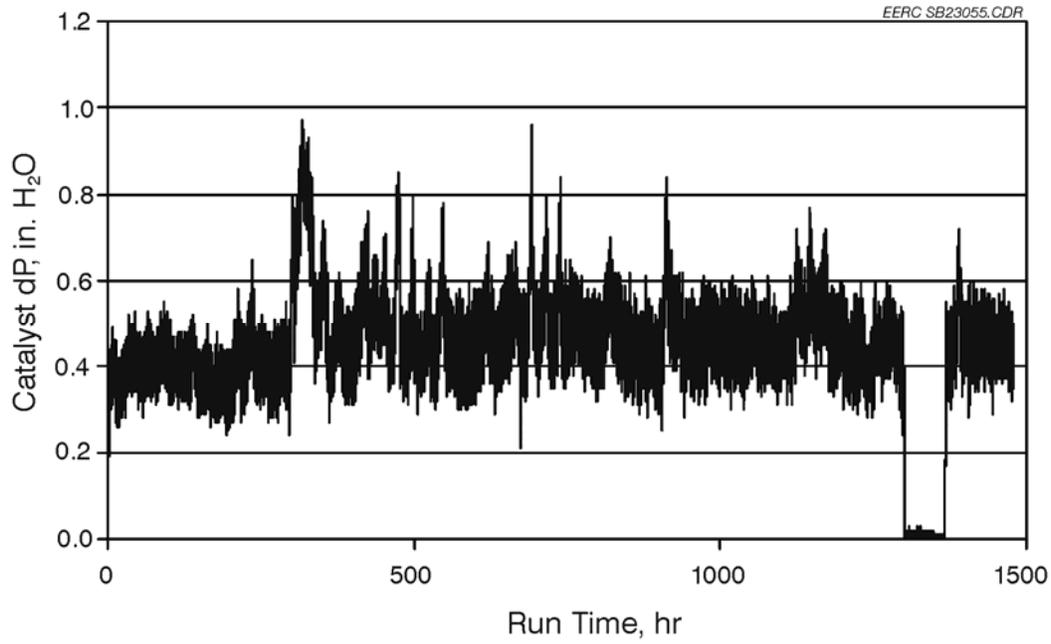
**Figure 8.** Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.



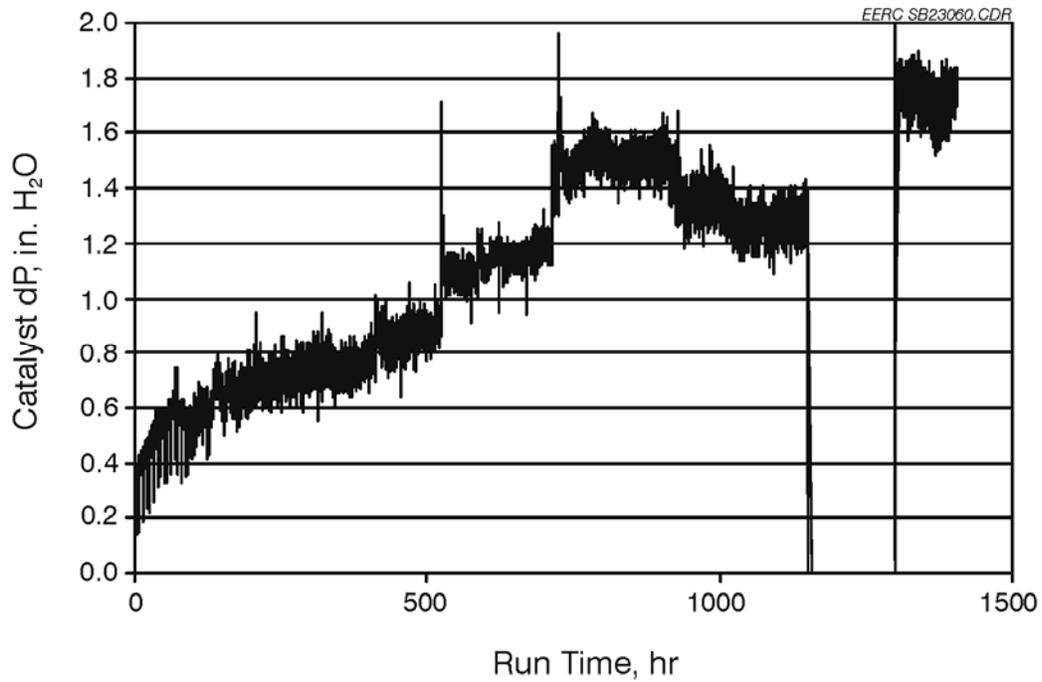
**Figure 9.** Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.



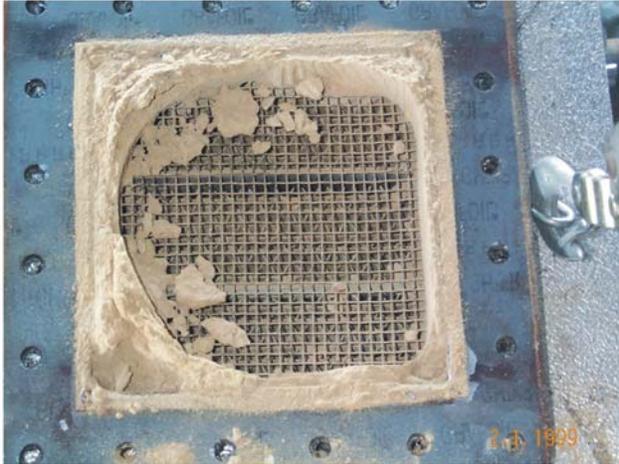
**Figure 10.** Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.



**Figure 11.** Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.



**Figure 12.** Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.



**Baldwin Station after 2 months**



**Coyote Station after 2 months**



**Columbia Station after 2 months**

**Figure 13.** Pictures of catalyst inlet after about 2 months of testing at each plant.

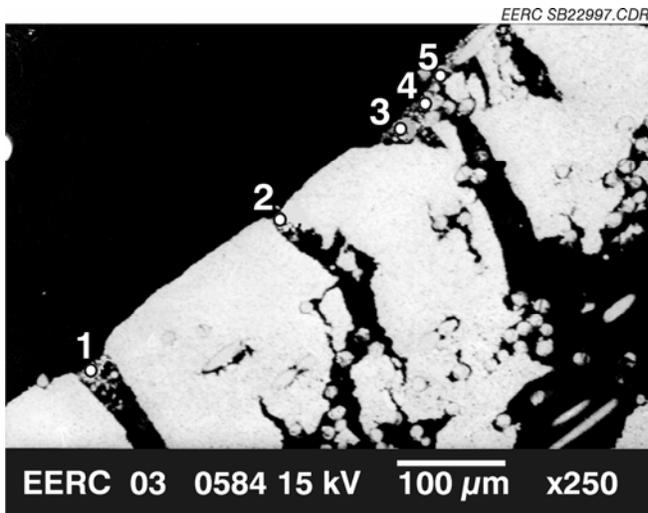


**Baldwin Station after 4 months**

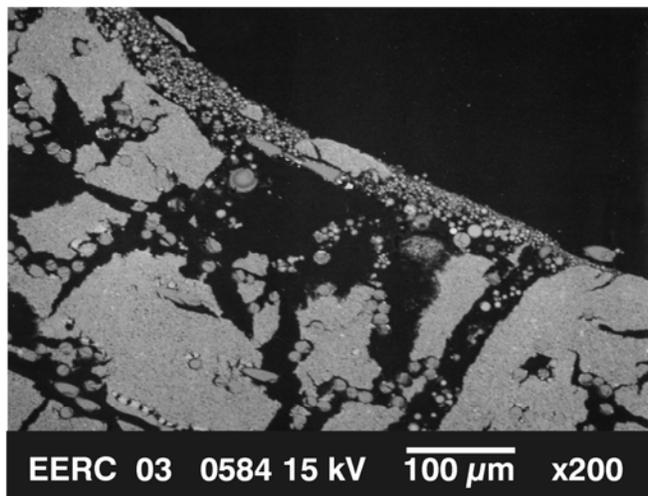


**Coyote Station after 4 months**

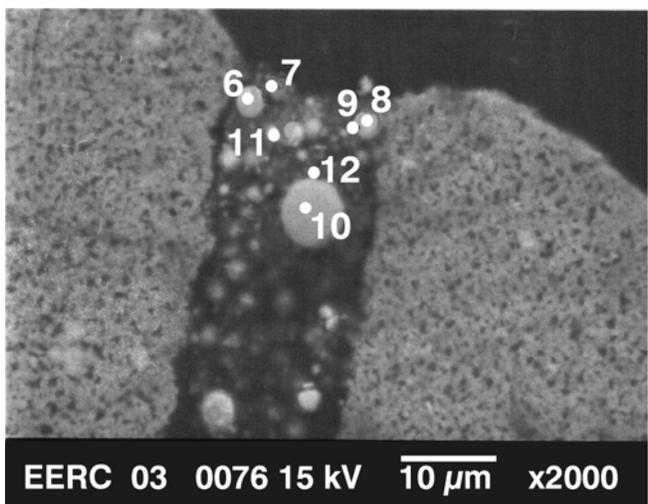
**Figure 14.** Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.



A



B

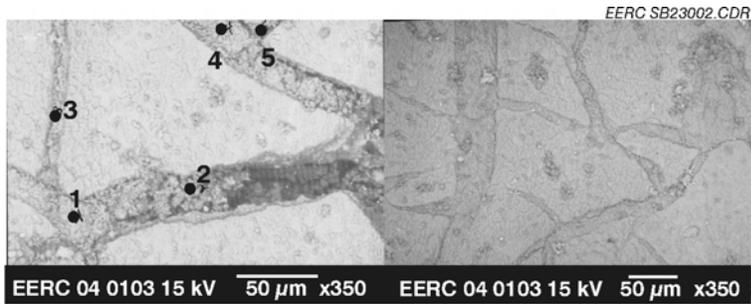


C

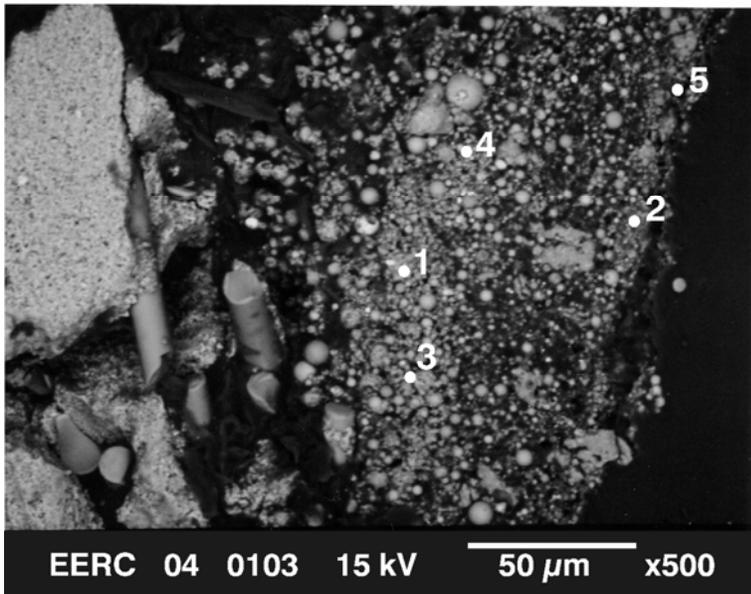
**Figure 15.** SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

**Table 3. Chemical Composition of Selected Points and Areas in Figure 15**

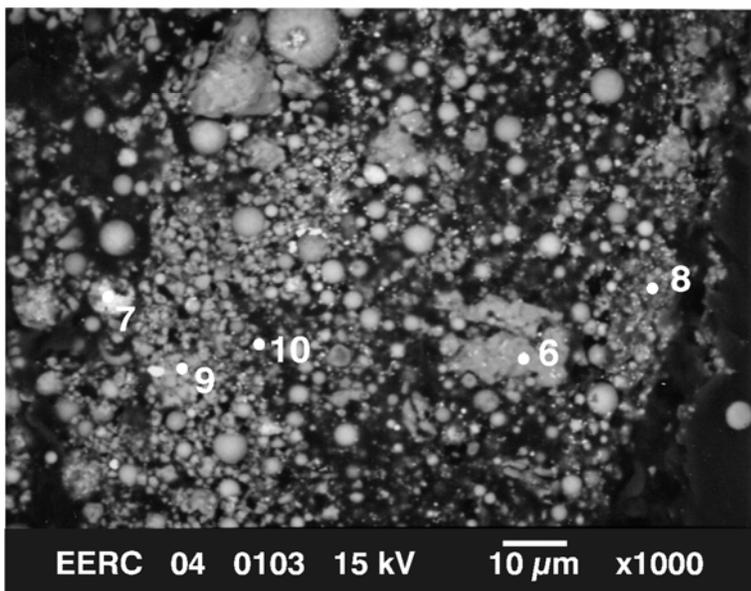
Chemical composition (normalized wt% equivalent oxide)						
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
<b>2.1.3</b>						
Na <sub>2</sub> O	0.6	1.0	2.1	0.3	0.5	2.7
MgO	4.3	2.5	6.3	0.7	1.6	7.6
Al <sub>2</sub> O <sub>3</sub>	14.8	16.0	15.6	15.5	14.7	0.9
SiO <sub>2</sub>	3.3	7.8	18.8	57.7	7.7	47.3
P <sub>2</sub> O <sub>5</sub>	2.3	2.1	0.5	0.6	1.8	0.0
SO <sub>3</sub>	30.7	20.4	17.7	0.0	29.0	0.8
K <sub>2</sub> O	0.7	0.0	1.0	0.4	0.9	0.9
CaO	28.8	28.7	28.1	22.5	34.9	28.4
TiO <sub>2</sub>	2.0	7.2	2.2	0.3	1.3	1.1
Fe <sub>2</sub> O <sub>3</sub>	11.4	12.9	6.2	0.0	7.6	7.9
BaO	1.1	1.4	1.4	2.0	0.0	2.5
Total	100	100	100	100	100	100
Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
<b>2.1.4</b>						
Na <sub>2</sub> O	1.7	0.4	0.5	2.2	1.3	1.7
MgO	4.5	6.4	5.9	5.0	3.4	6.4
Al <sub>2</sub> O <sub>3</sub>	5.0	2.4	3.0	19.2	10.8	3.8
SiO <sub>2</sub>	8.4	18.4	18.5	31.0	17.9	16.7
P <sub>2</sub> O <sub>5</sub>	1.8	0.9	1.0	0.0	1.7	1.2
SO <sub>3</sub>	37.9	1.7	5.3	0.0	22.5	13.9
K <sub>2</sub> O	0.4	0.0	0.0	0.9	0.8	0.0
CaO	31.4	52.6	49.0	28.9	30.6	45.4
TiO <sub>2</sub>	1.9	6.9	7.4	2.4	2.0	1.1
Fe <sub>2</sub> O <sub>3</sub>	7.1	5.7	6.0	6.3	6.1	6.5
BaO	0.0	4.6	3.5	4.2	2.9	3.3
Total	100	100	100	100	100	100



A



B

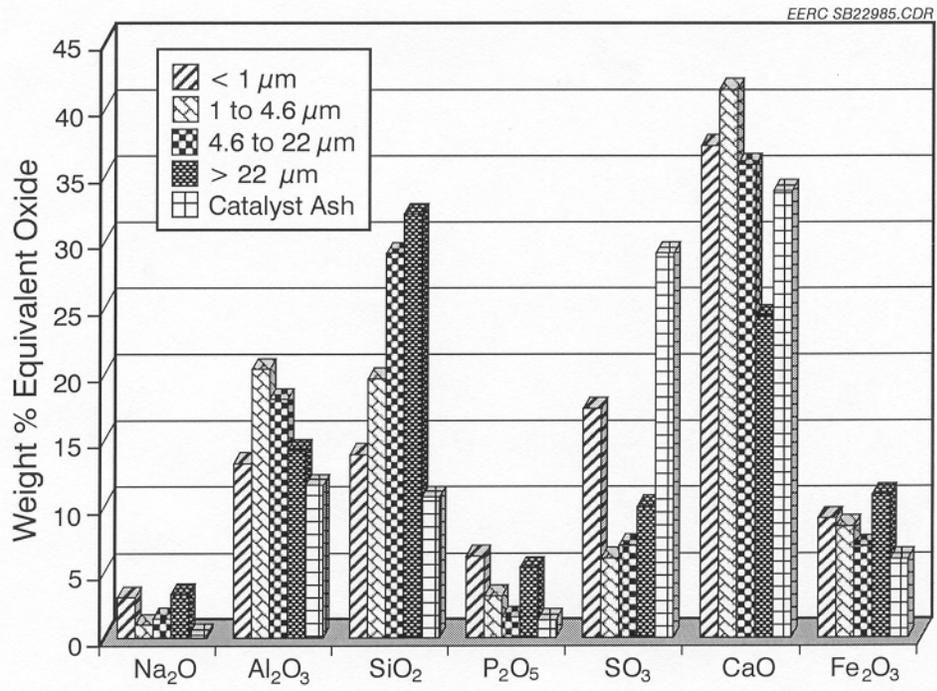


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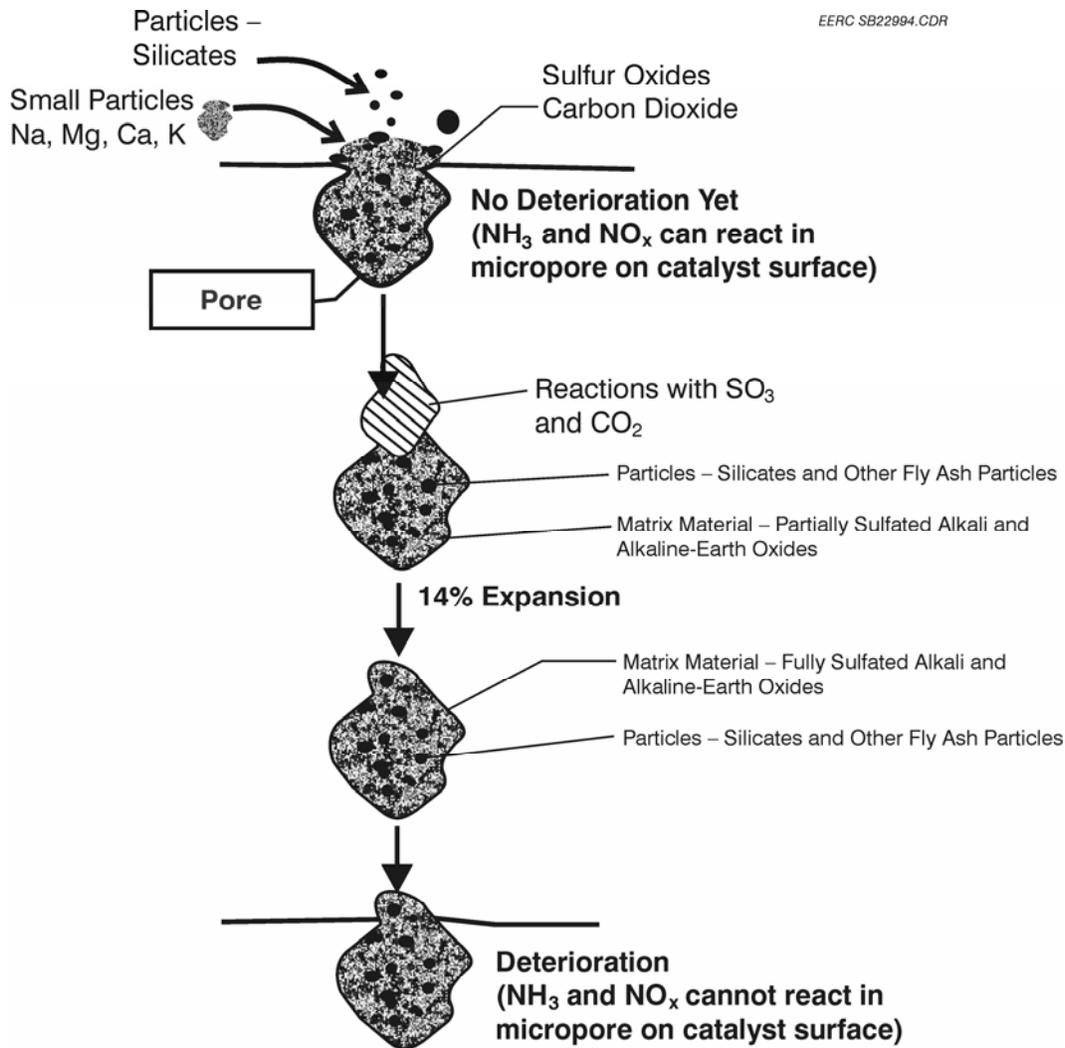
**Figure 16.** SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

**2.1.4.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16**

Chemical composition (normalized wt% equivalent oxide)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
<b>2.1.5</b>					
	6.7	1.9	7.1	6.2	3.1
Na <sub>2</sub> O	1.1	1.7	1.1	2.6	3.2
MgO	2.6	8.8	4.0	4.8	10.5
Al <sub>2</sub> O <sub>3</sub>	7.0	21.1	11.3	5.6	32.2
SiO <sub>2</sub>	0.2	2.4	0.0	0.2	0.9
P <sub>2</sub> O <sub>5</sub>	54.7	38.5	56.4	57.5	30.4
SO <sub>3</sub>	2.0	2.8	0.7	2.8	2.4
K <sub>2</sub> O	18.0	3.4	15.8	9.3	2.3
CaO	0.6	0.8	1.1	1.3	1.5
TiO <sub>2</sub>	5.8	5.1	2.1	6.5	9.8
Fe <sub>2</sub> O <sub>3</sub>	1.4	13.5	0.5	3.4	3.6
BaO					
Total	100	100	100	100	100
Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
<b>2.1.6</b>					
	9.5	2.6	10.4	8.9	4.4
Na <sub>2</sub> O	1.2	1.9	1.3	3.0	3.7
MgO	2.6	8.6	4.2	4.9	10.6
Al <sub>2</sub> O <sub>3</sub>	6.3	18.2	10.5	5.0	28.9
SiO <sub>2</sub>	0.1	1.9	0.0	0.1	0.7
P <sub>2</sub> O <sub>5</sub>	41.8	28.4	44.9	44.5	23.4
SO <sub>3</sub>	3.2	4.3	1.2	4.4	3.8
K <sub>2</sub> O	24.5	4.4	22.5	12.8	3.1
CaO	0.6	0.8	1.3	1.5	1.8
TiO <sub>2</sub>	7.7	6.6	2.9	8.9	13.2
Fe <sub>2</sub> O <sub>3</sub>	2.4	22.3	0.9	5.9	6.3
BaO					
Total	100	100	100	100	100



**Figure 17.** Comparison of entrained ash and deposited ash on catalyst for Columbia Station.



**Figure 18.** Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

### Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO<sub>x</sub> reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as (K<sub>1.5</sub>Na<sub>0.5</sub>)S<sub>2</sub>O<sub>7</sub> that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO<sub>3</sub> enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as  $\text{Na}_2\text{SO}_4$  and  $\text{K}_2\text{SO}_4$
2. Conversion of  $\text{SO}_2$  to  $\text{SO}_3$  in the bulk gas phase – catalytically active surface such as an SCR catalyst –  $\text{SO}_2 + \frac{1}{2} \text{O}_2 \rightarrow \text{SO}_3$
3. Pyrosulfate formation –  $\text{Na}_2\text{SO}_4 + \text{SO}_3 \rightarrow \text{Na}_2\text{S}_2\text{O}_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

**Table 5. Melting Points of Selected Pyrosulfate Compounds**

Compound	Temperature, °C	Temperature, °F
$\text{K}_3\text{Fe}(\text{SO}_4)_3$	618	1144
$\text{K}_3\text{Al}(\text{SO}_4)_3$	654	1209
$\text{KFe}(\text{SO}_4)_2$	694	1281
$\text{Na}_3\text{Fe}(\text{SO}_4)_3$	624	1155
$\text{Na}_3\text{Al}(\text{SO}_4)_3$	646	1195
$\text{NaFe}(\text{SO}_4)_2$	690	1274
$\text{Na}_2\text{S}_2\text{O}_7$	401	754
$\text{K}_2\text{S}_2\text{O}_7$	300	572
$(\text{K}_{1.5}\text{Na}_{0.5})\text{S}_2\text{O}_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power’s Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na<sub>2</sub>SO<sub>4</sub> particles are too small to be removed by scrubbing.

## **CONCLUSION: SCR IS NOT FEASIBLE FOR NO<sub>x</sub> REDUCTION AT MILTON R. YOUNG**

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO<sub>x</sub> reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO<sub>x</sub> control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
  - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
  - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
  - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
  - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
  - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.
- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.
- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.
- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO<sub>x</sub> reduction will not be possible. The key problems associated with lignites that have not been overcome, and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO<sub>x</sub> control at MRY's Units 1 and 2 are listed below:

- X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.
- X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.
- X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compared to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO<sub>3</sub> from SO<sub>2</sub>. The presence of SO<sub>3</sub> significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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## **APPENDIX B**

**Technical Description of SO<sub>2</sub> Controls (B1)**

**Coal Data for Future PTE Case (B2)**

## **B1 Technical Description of SO<sub>2</sub> Controls**

### **B1.0 Fuel Switching**

Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. One such fuel is lignite, which is a low Btu content, high ash, high moisture, medium sulfur content fuel. A typical lignite boiler is physically larger than a similarly rated unit designed for bituminous or sub-bituminous fuel due to the lower heat content of the lignite. The lignite fueled boiler must burn a greater mass of coal each hour to achieve the same heat input due to the lower heat content of the lignite fuel. Therefore, ancillary equipment such as coal crushers/dryers and conveyors, ductwork, etc. are designed larger to handle the greater quantities of coal and flue gas. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) sub-bituminous.

Firing sub-bituminous fuels such as PRB coal in boilers designed for lignite fuel results in a significantly lower coal feed rate for the same heat input, and lower flue gas quantities. If a lignite fired boiler is switched to PRB coal, gas velocities would slow approximately 20% in the boiler for similar heat inputs. Slowing the flue gas velocity affects heat transfer characteristics and steam generation capabilities. While the slower gas velocities may seem to enable additional heat extraction due to a lengthier gas residence time in the boiler, this is somewhat counterbalanced by the fact that the boiler operator must also maintain a minimum outlet temperature. Lower flue gas velocity, with the same flue gas heat capacity (PRB flue gas approx. 1.5% less than lignite), also translates into higher initial flue gas temperatures in the combustion zone, which might mean greater heat absorption in the waterwall portion of the furnace. However, an actual test burn is required to determine the exact effects.

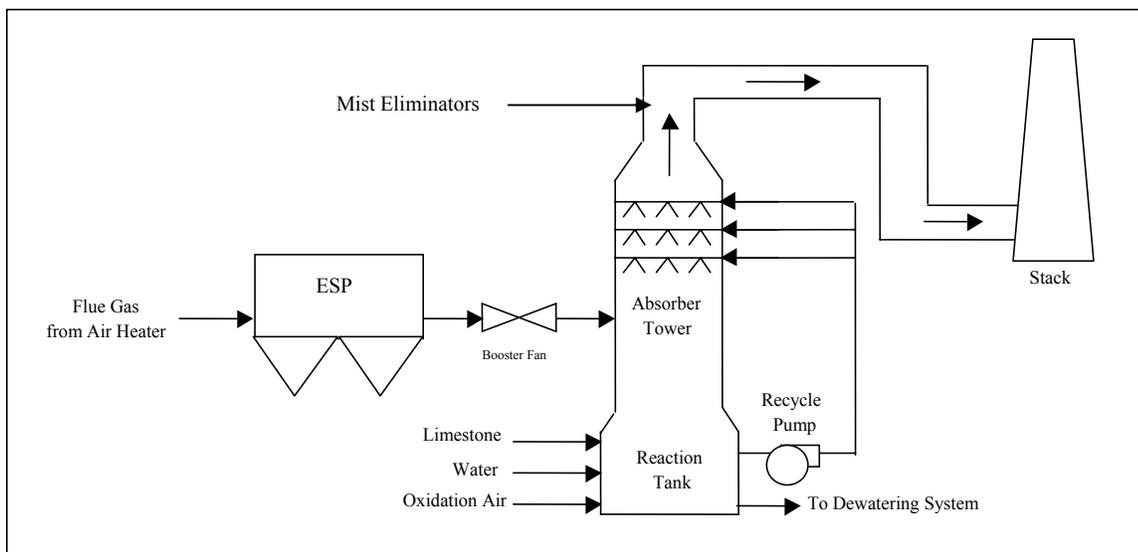
Switching to a fuel such as PRB coal will achieve significant SO<sub>2</sub> emission reductions. However, additional SO<sub>2</sub> control measures, such as post combustion controls might be required to achieve BART. Unfortunately, the removal efficiency of the post combustion technologies would be negatively affected by lower inlet flue gas SO<sub>2</sub> content. While a modern wet FGD system may readily achieve 95% SO<sub>2</sub> control on a medium or high sulfur fuel, when coupled with lower sulfur western fuels, the problem becomes one of diminishing returns. This should be easily understandable as one of the principal process variables affecting the performance of these systems is the inlet SO<sub>2</sub> concentration.

## B2.0 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate,  $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) as the byproduct, is commonly applied to coal-fired boilers. The gypsum byproduct is either landfilled or sold for commercial reuse.

A flow diagram of the wet FGD process is provided in Figure B-1. In the wet FGD process, a slurry of finely ground limestone ( $\text{CaCO}_3$ ) in water is recirculated through an absorber tower where it is brought into turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas via evaporation of water from the slurry.  $\text{SO}_2$  is simultaneously absorbed into the slurry where it forms sulfurous acid which reacts with the limestone, forming calcium sulfite hemihydrate ( $\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$ ) which can then be disposed of as a waste product or oxidized to calcium sulfate dihydrate or gypsum ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) before disposal or for commercial reuse. No commercial uses for sulfite waste products have been identified.

**Figure B-1. Wet FGD Process Flow Diagram**



Chemical reactions between the limestone and the absorbed  $\text{SO}_2$  take place within the slurry in the absorber, and in the absorber reaction tank, resulting in the formation of particles of  $\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$ . Some of the oxygen in the flue gas may participate in the reaction, resulting in the formation of particles of  $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$  as well. Air may be injected into the absorber sump to promote the

formation of gypsum and minimize the formation of calcium sulfite solids where a gypsum product is desired, either for ease of disposal or commercial use. The resultant slurry is then processed in a dewatering system prior to disposal or commercial use.

As the limestone reagent in the recirculating slurry is depleted, it is replenished with fresh slurry prepared by wet grinding of crushed limestone using reclaimed liquid from the dewatering system. Fresh water is also required to replace water lost to evaporation in the flue gas cooling process. Fresh water is often used to wash the mist eliminators, devices located at the scrubber exit to capture slurry droplets entrained in the exiting flue gas stream and return them to the scrubber. The mist eliminator wash removes accumulated materials from the mist eliminator chevrons, thus preventing solids buildup and pluggage. In addition, depending upon the mineral content of the coal, a portion of the reclaimed liquid from the dewatering process may be blown down, or disposed of, to prevent excessive accumulation of mineral salts in the slurry which could result in mineral scaling within the absorber equipment. The blow down rate varies with each plant. Fresh water makeup, both through the mist eliminator wash system and in the limestone grinding process, replaces the blow down and evaporative losses.

Lime scrubbers are very similar to limestone scrubbers. The use of lime rather than limestone can reduce the liquid-to-gas ratio and/or absorber size required to achieve a given SO<sub>2</sub> removal rate. Lime is sometimes used in wet FGD systems where extremely high SO<sub>2</sub> removal rates are desired or where limestone is not readily available. However, since lime is more expensive than limestone, the reagent cost is much higher for a lime system. Therefore, the vast majority of wet FGD systems are designed to use limestone as the neutralizing reagent.

Advantages of the wet FGD systems include lower operating costs, primarily due to the ability to use limestone instead of lime as a reagent, the production of a salable by-product and high removal efficiency. Also, wet FGD systems have a high turndown capability and plant operational flexibility is not hindered to the same degree as the semi-dry, CFB and FDA processes. This last advantage is important where wet FGD systems are applied to load following units. Disadvantages of wet FGD systems include corrosion due to a wet environment with corrosive chemicals including salts of sulfurous and sulfuric acid and hydrochloric acid. Also, because the wet systems are more mechanically complex, they typically require larger maintenance staff than the semi-dry, CFB and FDA alternatives. The greater mechanical complexity also contributes to a greater capital cost for wet FGD systems. Finally, because wet FGD systems completely saturate the flue gas stream, nearly

all the SO<sub>3</sub> or H<sub>2</sub>SO<sub>4</sub> vapor in the entering flue gas is condensed into aerosol droplets which are too small to be efficiently captured in the scrubber. Fifty percent or more of these droplets pass right through the scrubber. Where units are burning high sulfur fuels, this can cause a plume opacity problem. Wet FGD systems commonly achieve 95% percent SO<sub>2</sub> removal efficiencies in commercial applications.

### **B3.0 Semi-Dry Flue Gas Desulfurization**

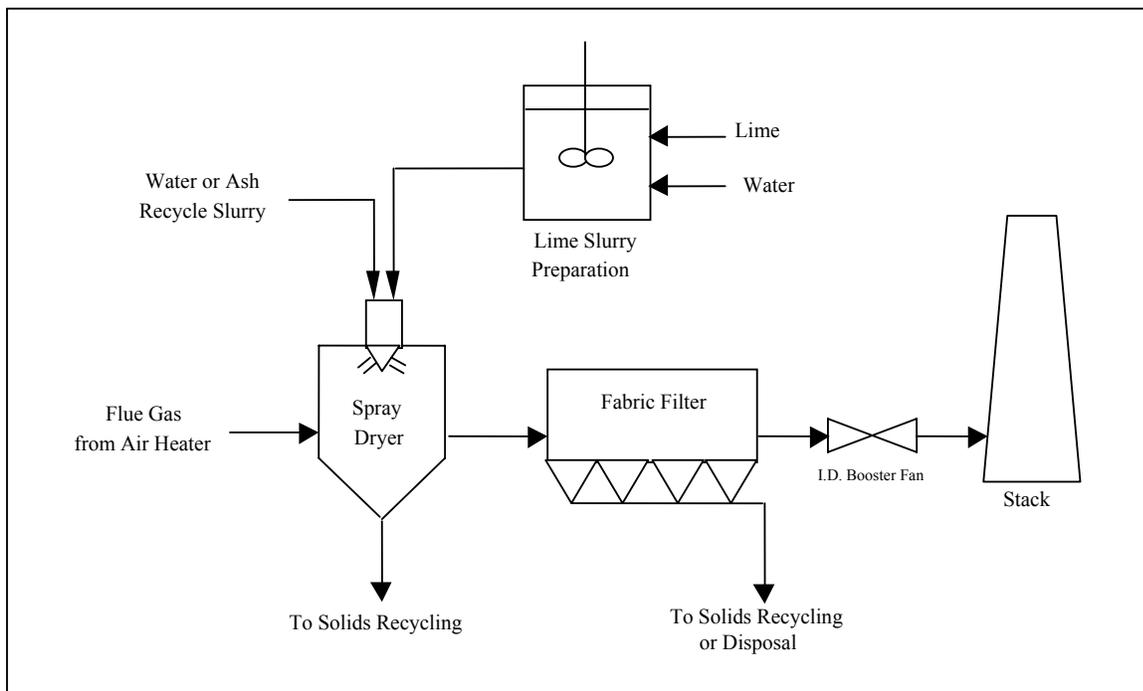
As an alternative to wet FGD technology, the control of SO<sub>2</sub> emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. The semi-dry FGD process became popular in the U.S. beginning in the late 1970s as a way to comply with the New Source Performance Standards (NSPS) for electric utility steam generating units for which construction commenced after September 18, 1978 (40 CFR Part 60, Subpart Da). These standards require that all new coal-fired electric utility boilers be equipped with a “continuous system of emission reduction” for SO<sub>2</sub>. However, the standards allowed SO<sub>2</sub> removal efficiency as low as 70 percent for facilities burning low-sulfur coal. The semi-dry FGD process could meet this requirement, and was often selected as the SO<sub>2</sub> control technology for many new coal-fired power plants that were built in the 1970s and 1980s and designed to burn low-sulfur western coal. In the late 1980s and through the 1990s, most of the new coal-fired boilers built in the U.S. were for small Independent Power Producer (IPP) projects, and many of these also selected the semi-dry/lime FGD process.

There are several variations of the semi-dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer Absorber and Circulating Fluidized Bed absorber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling.

A schematic diagram of the spray dryer FGD process is provided in Figure B-2. In the spray dryer FGD process, boiler flue gas is introduced into a Spray Dryer Absorber (SDA) into which hydrated lime (calcium hydroxide, Ca(OH)<sub>2</sub>) and water are added as dispersed droplets. The Ca(OH)<sub>2</sub> reacts with SO<sub>2</sub> that has been absorbed into the water to form primarily calcium sulfite and some calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. Because the total water feed rate is much lower than that of the wet FGD process,

the reaction products are dried in the SDA and the flue gas is only partially saturated. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained well above the saturation, or dewpoint, temperature (typically 30-40 °F above saturation) to avoid corrosion problems. Cooling the gas to this point significantly increases the SO<sub>2</sub> control efficiency over injection into hot, dry flue gas. The reaction product leaves the SDA as fine dry particles entrained in the flue gas. The flue gas enters the SDA at the top and flows downward, cocurrent with the introduced neutralizing agent. This characteristic is the opposite of the wet FGD system which introduces flue gas into the bottom of the absorber, countercurrent to the falling slurry spray.

**Figure B-2 Spray Dryer FGD Process Flow Diagram**



In the lime spray drying process, quicklime (CaO) is slaked with water to form lime slurry which is then injected into the SDA along with additional water through a rotary atomizer or dual fluid nozzle or similar apparatus. Recycled PM from the PM control equipment downstream of the SDA is often mixed with the lime slurry before injection into the SDA to provide additional surface area for SO<sub>2</sub> absorption. The flue gas is introduced into the SDA in a manner designed to maximize the contact between the gas and the droplets and to prevent slurry impingement on the walls of the SDA. The turbulent mixing of the flue gas and the slurry droplets promotes rapid absorption of SO<sub>2</sub> into the water of the slurry droplets. The chemical reactions between the absorbed SO<sub>2</sub> and the calcium hydroxide take place within the droplet as the flue gas moves through the SDA. The flue gas is

cooled and partially humidified as the water evaporates, leaving a mixture of fly ash and dry powdered reaction product entrained in the flue gas. Some of the solid particles fall to the bottom of the reactor and are collected by a waste handling system. Entrained particles are collected in an electrostatic precipitator (ESP) or fabric filter (FF) downstream of the SDA.

An additional distinguishing characteristic of the SDA is that it must be located upstream of a particulate control device, as opposed to the wet FGD process which is normally the last flue gas treatment process before discharge to the stack. For new plants, this point is not of such great importance. However, when retrofitting FGD equipment to an existing coal-fired plant, which already has particulate control equipment installed, this becomes an important point. If a suitable location exists for the insertion of a new SDA upstream of an existing PM control device, and if the performance of the existing PM control device would not be overly degraded by the additional PM loading, then the retrofit process would consist only of installation of the SDA, reagent preparation and waste handling systems. However, many times one, or both, of these conditions do not exist and the choice to utilize an SDA requires the installation of a new PM control device, such as an ESP or fabric filter. Where this situation exists, the capital cost of the SDA option increases significantly.

Semi-dry processes have some notable advantages compared to wet FGD processes including a dry byproduct which can be handled with conventional ash handling systems. Because the semi-dry system does not have a truly wet zone, corrosion problems in the SDA are eliminated, or significantly reduced, to the point exotic materials of construction are not required. Spray dryer systems utilize less complex equipment resulting in a reduced capital cost and allowing somewhat smaller operations and maintenance staff. Where a fabric filter is utilized as the downstream particulate control device for a semi-dry process, the lime content of the filter cake on the fabric filter reacts with condensed  $\text{SO}_3$  in the flue gas stream capturing and neutralizing the acid aerosol. Consequently, semi-dry FGD options, paired with a fabric filter for PM control, have virtually zero emissions of acid aerosols.

The primary disadvantages of the lime spray dryer process make it less likely to be applied to large power plant boilers, especially those firing high-sulfur coal. The lime spray dryer requires the use of lime, which is much more expensive than limestone. While lime contains approximately 1.8 times more calcium than limestone on a mass basis, lime can cost up to five times more than limestone on a mass basis. Therefore, reagent costs for a lime based process are typically higher than a limestone-based process for a given application.

Wastes from semi-dry processes have very limited possibility for reuse due to fly ash contamination. Also, where fly ash might be sold for other uses, contamination with the semi-dry FGD reaction products typically eliminates commercial options for reuse. Where fly ash sales are to be maintained, a second PM control device would be required for the semi-dry FGD system exhaust stream, increasing both capital and O&M costs.

SDAs have much more stringent size limitations than wet FGD scrubbers. Typically units larger than 250 to 300 MW will require at least two SDAs, thus driving up capital costs and system complexity for larger units, while wet FGD systems can handle up to 1000 MW in a single absorber module. SDAs do not have the same turndown capabilities as wet FGD absorbers, further limiting applicability for load following units. Finally, lime spray dryer systems do not have the same level of experience with high SO<sub>2</sub> removal requirements in high sulfur applications that wet FGD systems have.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO<sub>2</sub> removal levels similar to wet FGD systems in the U.S. Table B-1 lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. As can be seen in the column titled Efficiency, two units were permitted with an SO<sub>2</sub> removal efficiency of 94.5% and one with 95%. However, these units typically use a lower sulfur fuel and achieve an emissions limit in the range of 0.12 to 0.17 lb SO<sub>2</sub>/mmBtu.

**Table B-1 – Recent Dry FGD Permits From RBLC**

<b>RBLC ID</b>	<b>Facility</b>	<b>Process</b>	<b>Fuel</b>	<b>Size</b>	<b>Unit</b>	<b>Control Device</b>	<b>Emission Limit (lb/mmBtu)</b>	<b>Estimated Efficiency</b>	<b>Permit Date</b>
*NE-0018	Whelan Energy Center	Unit 2 Utility Boiler	PRB coal	2,210	mmBtu/hr	Spray Dryer Absorber (SDA)	0.12	NA	3/30/2004
AR-0074	Plum Point Energy	Boiler, Unit 1 - SN-01	Bituminous Coal	800	MW	Dry Flue Gas Desulfurization	0.16	NA	8/20/2003
MT-0022	Bull Mountain, No. 1, LLC - Roundup Power Project	Boiler, PC No. 1	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
MT-0022		Boiler, PC No. 2	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
IA-0067	MidAmerican Energy Company	CBEC 4 Boiler	PRB Coal	7,675	mmBtu/hr	Lime Spray Dryer Flue Gas Desulfurization	0.1	92	6/17/2003
KS-0026	Holcomb Unit #2	Boiler, PC	Subbituminous Coal	660	MW	Dry Flue Gas Desulfurization	0.12	94	10/08/2002
WY-0057	WYGEN 2	500 MW PC Boiler	Subbituminous Coal	500	MW	Semi-Dry Lime Spray Dryer Absorber	0.1	NA	9/25/2002
MO-0050	Kansas City Power & Light Co. - Hawthorn Station	PC Boiler,	Coal	384	T/H	Dry Flue Gas Desulfurization	0.12	NA	8/17/1999
WY-0039	Two Elk Generation Partners, Limited Partnership	PC Fired Boiler	Coal	250	MW	Lime Spray Dry Scrubber	0.17	91	2/27/1998
WY-0047	Encoal Corporation-Encoal North Rochelle Facility	PC Fired Boiler	Subbituminous Coal	3,960	mmBtu/hr	Lime Spray Dryer	0.2	73	10/10/1997
WY-0048	Wygen, Inc. - Wygen Unit One	Boiler, PC	Subbituminous Coal	80	MW	Circulating Dry Scrubber	0.2	92	9/6/1996
PA-0133	Mon Valley Energy Limited Partnership	PC Fired Boiler	Bituminous Coal	966	mmBtu/hr	Spray Dry Absorption	0.25	92	8/8/1995

**Table B-1 – Recent Dry FGD Permits From RBLC (cont.)**

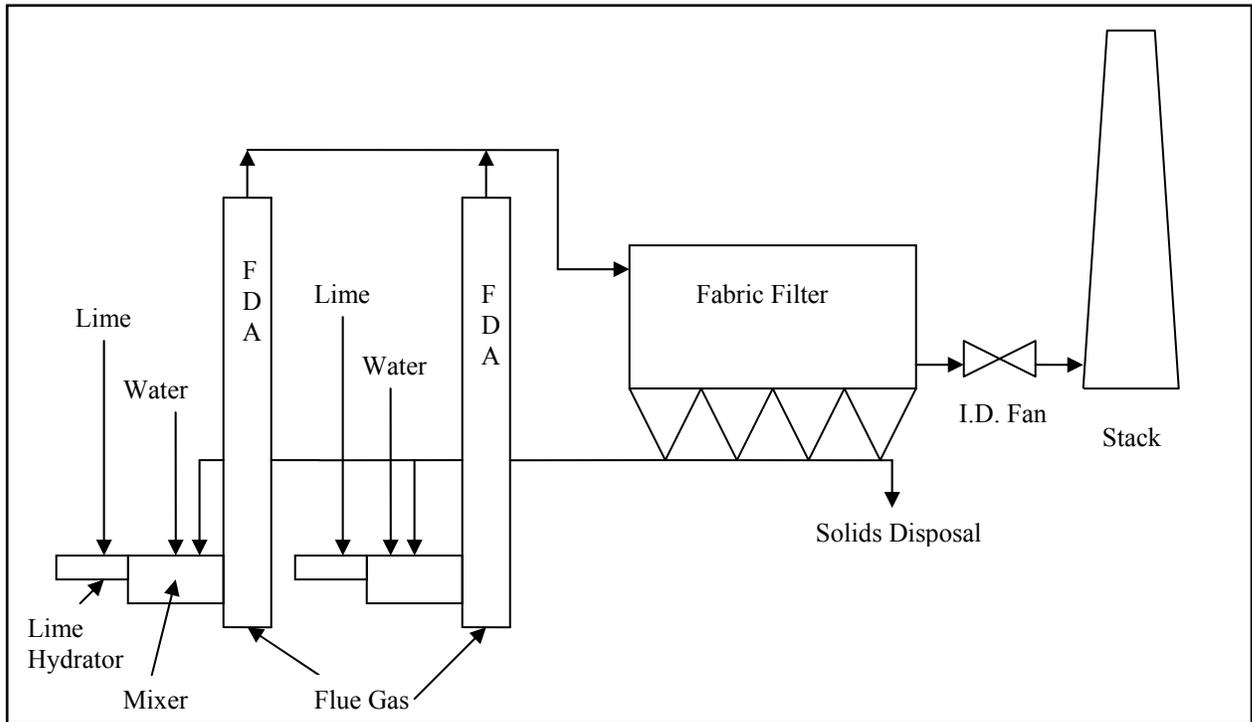
<b>RBLC ID</b>	<b>Facility</b>	<b>Process</b>	<b>Fuel</b>	<b>Size</b>	<b>Unit</b>	<b>Control Device</b>	<b>Emission Limit (lb/mmBtu)</b>	<b>Estimated Efficiency</b>	<b>Permit Date</b>
VA-0213	SEI Birchwood, Inc.	PC Fired Boiler	Coal	2,200	mmBtu/hr	Lime Spray Drying System (FGD System)	220	94	8/23/1993
WY-0046	Black Hills P&L Neil Simpson U	PC Fired Boiler	Coal	80	MW	Circulating Dry Scrubber	0.17	95	4/14/1993
MI-0228	Indelk Energy Services Of Otsego	Boiler (Coal)	Coal	778	mmBtu/hr	Dry Scrubber	0.32	90	3/16/1993
NC-0057	Roanoke Valley Project Ii	Boiler, PC-Fired	Coal	517	mmBtu/hr	Dry Lime Scrubbing	0.187	93	12/7/1992
SC-0027	South Carolina Electric And Gas Company	Boiler, PC-Fired Unit No. 1	Coal	385	MW	Spray Dryer Absorber	0.25	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 2	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 3	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
NJ-0015	Keystone Cogeneration Systems, Inc.	PC-Fired Boiler	Coal, Bituminous	2,116	mmBtu/hr	Spray Dryer Absorber	0.16	93	9/6/1991
NC-0054	Roanoke Valley Project	Boiler, PC-Fired	Coal	1,700	mmBtu/hr	Dry Lime FGD	0.213	92	1/24/1991
NJ-0014	Chambers Cogeneration Limited Partnership	2 PC-Fired Boilers	Coal	1,389	mmBtu/hr (each)	Spray Dryer Absorber	0.22	93	12/26/1990
VA-0176	Hadson Power 13	Boiler	Coal	30,228	lb/hr coal	Lime Spray Dryer	0.162	92	8/17/1990
VA-0171	Mecklenburg Cogeneration Limited Partnership	PC Fired, Boiler, 4 Units	Bituminous Coal	834.5	mmBtu/hr	Spray Dryer, Fabric Filter	0.172	92	5/9/1990

#### **B4.0 Flash Dryer Absorber Flue Gas Desulfurization**

The Flash Dryer Absorber (FDA) is a further development of the lime spray dryer process. The approach is similar in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, waste solids from the particulate control process are added to the reagent feed stream to the reactor. Similar to the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Recycled PM, along with absorption products and unreacted lime, are collected downstream of the FDA and a sizable fraction recycled to the FDA. Unlike the SDA, the FDA recycles a very high fraction of the captured PM. Because of this, the ratio of solids to liquid in the reagent stream injected into the FDA reactor is much higher than the SDA. The ratio is so much higher that the wetted recycled solids are still a relatively dry free flowing stream after wetting in the mixing stage<sup>2</sup>. Because the reagent stream starts off much higher in solids, the liquid film thickness on the wetted solids is much thinner and the drying time for the injected solids is much shorter than a typical SDA. This allows the FDA to function with a significantly smaller reactor compared to the typical SDA absorber vessel. Like the SDA, the water injection rate of the FDA is controlled to lower the flue gas temperature to optimize the SO<sub>2</sub> control efficiency while avoiding saturation and the accompanying corrosion problems. Unlike the SDA, the flue gas is flows vertically upward in the FDA. Figure B-3 is a schematic presentation of the FDA design.

The FDA utilizes quicklime (CaO) instead of hydrated lime as a reagent. The reasoning given for this by the designers is that when purchasing lime, although the price per ton is similar, the quicklime has 32% more calcium (SO<sub>2</sub> neutralization component) per ton than hydrated lime. Also, because quicklime is denser (900-1,200 kg/m<sup>3</sup> for quicklime vs. 450-640 kg/m<sup>3</sup> for hydrated lime), both transport and onsite storage capacity requirements can be smaller. However, direct injection of quicklime has resulted in less efficient reagent utilization compared to hydrated lime use. This is theorized to be due to hot spots created in the reaction zone by the hydration of the quicklime. The heat of hydration of quicklime is approximately 1.1 mmBtu/ton, so there is considerable heat evolved during the hydration step. To avoid adding this heat to the flue gas or creating hot spots that could reduce lime utilization, the FDA design incorporates a separate lime hydration stage where more than the stoichiometrically required amount of water is added to the quicklime in stages. The super stoichiometric water is heated during the slaking process and evaporates, leaving dry hydrated lime. The hydrated lime, recycled solids and water are then combined in a mixing vessel just prior to injection into the reactor.

**Figure B-3 Flash Dryer Absorber FGD Process Flow Diagram**



Like the SDA, the FDA must be followed by a PM control device to capture the dry solids in the FDA exhaust. The great majority of these solids are recycled back to the FDA. The non recycled fraction is a mixture of calcium sulfite/sulfate solids and fly ash for which limited possibilities for reuse exist. Also, in those instances where fly ash sales produce an income for the power plant, addition of the FDA solids to the fly ash will likely render the waste solids stream valueless. Where the plant receives revenue from fly ash sales, the lost revenue would be an additional cost of FDA implementation because the fly ash is used as a surface area enhancer in FDA operation.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002<sup>3</sup>, Alstom cited a 280 MW plant in China with an 85% SO<sub>2</sub> removal efficiency. This plant had an FDA installed upstream of an ESP. Dry and semi-dry scrubbers installed upstream of a fabric filter have been consistently shown to achieve approximately 5-10% greater acid gas removal efficiency due to absorption and neutralization taking place in the filter cake of the fabric filter. Typically ESPs downstream of an FDA or other dry or semi-dry SO<sub>2</sub> scrubbing system are attributed no more than 5% SO<sub>2</sub> removal efficiency.

Advantages of the FDA over wet FGD systems are similar to those described for the semi-dry process described previously, including ease of byproduct handling, much less aggressive corrosion conditions allowing the use of more common, less expensive materials of construction, less complex equipment, and potentially enhanced SO<sub>3</sub> control when combined with a fabric filter. FDA advantages also include a significantly smaller reactor/absorber which translates into a lower area requirement than either wet or semi-dry FGD systems, though manufacturers often provide multiple FDA's, even on smaller units.

Disadvantages of the FDA, when compared to the wet FGD system are similar to those described for the semi-dry process, including reactor size limitations, lower turndown ratio, more expensive reagent, and lack of byproduct market value.

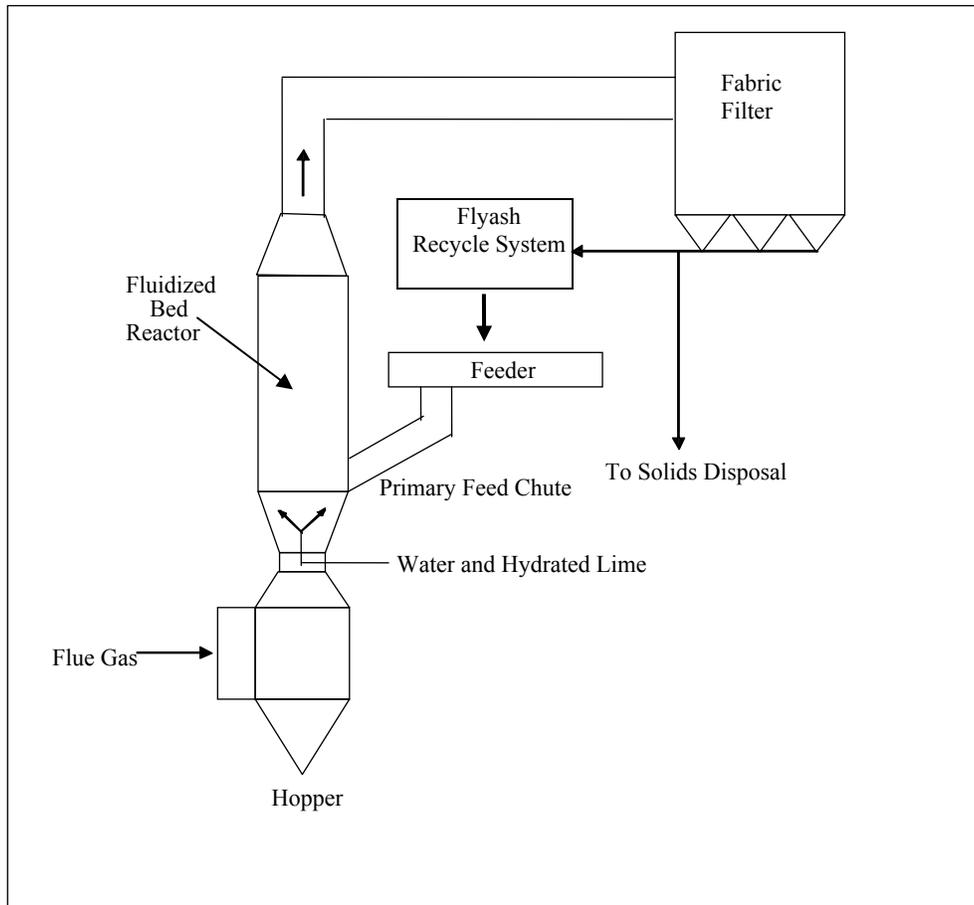
### **B5.0 Circulating Fluidized Bed Absorber Flue Gas Desulfurization**

In the fluidized bed dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. High velocity movement of the gas through the reactor suspends the solids creating a fluidized bed. A CFB absorber vessel would be a smaller diameter than the SDA discussed previously in this report. A schematic representation of the CFB process is shown in Figure B-4. The smaller diameter absorber helps maintain higher flue gas velocities required to maintain the fluidized bed. Water injected into the venturi throat cools the flue gas and wets the recycled solids similar to the process described previously for the FDA. Dry, powdered, hydrated lime is injected into the bed near the bottom of the absorber vessel, above the venturi and dissolves in the thin water film on the recycled solids. SO<sub>2</sub> from the flue gas is also absorbed into the evaporating water film and reacts with the lime to produce both calcium sulfite and sulfate reaction products. Flue gas temperatures are typically reduced from 300 °F to approximately 160 °F to optimize SO<sub>2</sub> removal efficiency. The evaporation of the water cools and partially humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed helps prevent solids deposition inside the absorber and promotes regeneration of the particle surfaces, exposing additional lime to react with absorbed SO<sub>2</sub>. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CFB absorber. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization. CFB absorbers have been installed with both fabric filters and ESPs for particulate control.

The CFB absorber dry scrubbing process utilizes a bed of fluidized particles to provide an extended surface area for wetting, evaporation and SO<sub>2</sub> absorption. The extended surface decreases the time required for SO<sub>2</sub> absorption. Even though the gas velocity is higher than a wet FGD absorber or an SDA, the CFB absorber is not taller than either of these vessels.

The CFB has many of the same advantages of the SDA and FDA such as a dry byproduct, simplified waste handling systems and conventional materials of construction. CFBs also have less rotating equipment than wet FGD or SDA systems, thus simplifying maintenance requirements somewhat. Like the SDA and FDA, the CFB application with a fabric filter for particulate collection will also achieve very good acid aerosol control. Unlike the SDA the CFB does not require dual fluid nozzles or atomizers in the absorber. This feature simplifies the absorber maintenance of a CFB over that of the SDA. Also, because lime and water are injected separately into the CFB, increased reagent requirements can be met without increasing saturation of the flue gas.

**Figure B-4 – Circulating Fluidized Bed FGD System**



Disadvantages of the CFB process include higher reagent cost and lower utilization than SDAs in similar applications and more limited turndown capability. In a recent study<sup>2</sup> the National Lime Association determined that compared to CFB's in similar applications, the SDA achieved slightly lower SO<sub>2</sub> removal with slightly better reagent utilization. Because CFBs must maintain gas velocities within a fluidizing range, a recycle duct from the absorber exhaust to the inlet is sometimes included to allow for partial recycle of flue gas to maintain bed velocity and improve the turndown ratio. Similar to the SDA and FDA processes, CFBs are size limited and multiple absorbers are required for applications larger than 250-300 MW.

An additional disadvantage the CFB has over the SDA is pressure drop. Because the CFB must maintain the fluidized bed condition, the pressure drop over the absorber is typically 8-10 in. w.g. compared to an SDA at 6-8 in. w.g. and a wet FGD system at approximately 6.0 in. w.g.

### **B6.0 Powerspan Electro Catalytic Oxidation (ECO™) Technology**

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO<sub>x</sub>, SO<sub>2</sub>, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels, a barrier discharge reactor and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO<sub>x</sub>, SO<sub>2</sub>, and mercury to produce sulfur trioxide (SO<sub>3</sub>), sulfuric acid (H<sub>2</sub>SO<sub>4</sub>), nitric acid (HNO<sub>3</sub>) and oxidized metallic species (e.g., mercury). The flue gas stream then enters the bottom of the ECO™ scrubber where the lower loop cools the flue gas and removes a portion of the SO<sub>2</sub>, acid gasses produced in the barrier reactor (H<sub>2</sub>SO<sub>4</sub> & HNO<sub>3</sub>) and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO<sub>2</sub>, NO<sub>2</sub>, acid gasses and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO™ process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury.

As a reagent the system utilizes aqueous ammonia in two scrubber loops, with varying pH to control collection efficiency in the lower and upper loops. The ammonia reacts with the collected SO<sub>2</sub> in aqueous solution to produce ammonium sulfate as a byproduct. The ammonium sulfate is

then salable as fertilizer, thus turning byproduct disposal into a profitable venture for system operators. Captured mercury and other oxidized metals are removed from the scrubber bleed stream with activated carbon and disposed of as a hazardous waste. Ash and insoluble metals are filtered from the scrubber bleed stream before fertilizer production and disposed of with other particulate wastes from upstream particulate control equipment. The ammonium sulfate can be either, sold as an aqueous product, or crystallized, granulated and sold.

In addition to high removal efficiencies for SO<sub>2</sub>, NO<sub>x</sub>, and mercury, the ECO™ process claims to achieve high levels of fine particulate control in the WESP. Powerspan claims a routine SO<sub>2</sub> removal efficiency of >98% with inlet concentrations up to approximately 2,000 ppm. SO<sub>2</sub> levels at LOS Unit 2 are commonly about 1,399 parts per million. NO<sub>x</sub> removal is stated to be up to 90% with a 0.05 lb NO<sub>x</sub>/mmBtu outlet condition achievable. Mercury removal of 75-85% is also reported by Powerspan for the ECO™ process.

Powerspan performed an extended pilot plant demonstration at R.E. Burger Station Units 4&5. The pilot demonstration project treated a slipstream of approximately 110,000 scfm and demonstrated performance, reliability and economics. The demonstration program started in January, 2004. Powerspan recently indicated that they are scaling the reactor and scrubber for optimum cost and space arrangement and incorporating lessons learned from the pilot plant operation. It is important for the purposes of this BART study to note that coproduct crystallization and granulation equipment was not included in the pilot plant operation. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during pilot plant operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a deficiency in the pilot plant program. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO<sub>2</sub> scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. No full size commercial scale ECO™ systems have been installed or operated at the time of this report.

1. [http://www.coaleducation.org/Ky\\_Coal\\_Facts/coal\\_resources/coal\\_properties.htm](http://www.coaleducation.org/Ky_Coal_Facts/coal_resources/coal_properties.htm)
2. “Economics of Lime and Limestone for Control of Sulfur Dioxide”; DePriest, William & Gaikwas, Rajendra P. ; National Lime Association ([www.lime.org/NLADryFGD.PDF](http://www.lime.org/NLADryFGD.PDF)); September, 2002.
3. “Alstom Power’s Flash Dryer Absorber For Flue Gas Desulfurization”, Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

## **B2 – Coal Data for Future PTE Case**

# COTEAU

THE COTEAU PROPERTIES COMPANY

A SUBSIDIARY OF THE NORTH AMERICAN COAL CORPORATION

## FREEDOM MINE

204 County Road 15  
Beulah, ND 58523-9475

(701) 873-2281 • Fax (701) 873-7226

January 13, 2006

Mr. Robert J. Bartosh  
Senior Vice President and Chief Operating Officer  
Dakota Coal Company  
P.O. Box 5540  
Bismarck, ND 58506-5540

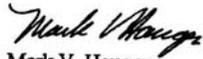
Dear Mr. Bartosh:

Enclosed is the Freedom Mine's long-range coal quality projection for the Leland Olds Station, as requested by Dakota Coal Company.

If you have any questions, please contact me.

Sincerely,

THE COTEAU PROPERTIES COMPANY



Mark V. Haugen  
Engineering Manager

MVH:lr  
Enc.

cc: w/enc.  
Karl Lemmerman  
Dean Bray

**THE COTEAU PROPERTIES COMPANY**  
**PROJECTED COAL QUALITY--AS RECEIVED BASIS**

**LELAND OLDS STATION**  
**UNITs I & II**

Year	AS DELIVERED COAL QUALITY	
	Sulfur	Btu
2012	0.83	6,778
2013	0.79	6,787
2014	0.99	6,764
2015	1.02	6,751
2016	0.99	6,735
2017	1.12	6,774
2018	1.09	6,733
2019	1.13	6,766
2020	1.12	6,780
2021	1.00	6,799
2022	0.99	6,830
2023	1.06	6,829
2024	1.06	6,735
2025	0.96	6,673
2026	0.94	6,548
2027	0.74	6,777
2028	0.83	6,678
2029	0.78	6,666
2030	0.75	6,630
2031	0.78	6,753
2032	0.87	6,689
2033	0.74	6,610
2034	0.70	6,747
2035	0.70	6,754
2036	0.70	6,760
2037	0.70	6,762
2038	0.71	6,756
2039	0.71	6,751
2040	0.73	6,752
<b>TOT / AVE</b>	0.88	6,736
<b>MINIMUM</b>	0.70	6,548
<b>MAXIMUM</b>	1.13	6,830

1/12/06

## **APPENDIX C**

### **Technical Description of Particulate Matter Controls (C1)**

## Appendix C1 – Technical Description of Particulate Matter Controls

### C1.0 FUEL SWITCHING

Fuel switching along with flue gas conditioning is a viable method of reducing particulate matter emissions in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. One such fuel is lignite, which is a low Btu content, high ash, high moisture, and medium sulfur content fuel. A typical lignite boiler is physically larger than a similarly rated unit designed for bituminous or sub-bituminous fuel due to the lower heat content of the lignite. The lignite fueled boiler must burn a greater quantity of coal per hour to achieve the same heat input due to the lower heat content of the lignite fuel. Therefore, ancillary equipment such as pulverizers, coal conveyors, ductwork, etc. are designed larger to handle the greater quantities of coal and flue gas.

Firing sub-bituminous fuels such as PRB in boilers designed for lignite fuel result in a significantly lower coal feed rate for the same heat input, and lower flue gas quantities. If a lignite fired boiler is switched to PRB coal, gas velocities would slow approximately 20% in the boiler for similar heat inputs. Lower flue gas velocity, with the same flue gas heat capacity (PRB flue gas is approximately 1.5% less than lignite), also translates into higher initial flue gas temperatures in the combustion zone, which might mean greater heat absorption in the waterwall portion of the furnace. However, an actual test burn is required to determine the exact effects.

Fly ash conditioning methods installed upstream of an ESP usually involve the injection of a chemical into the flue gas stream to control the electrical resistivity of the fly ash. Conditioning systems can also be used to cause coagulation of the dust particles, agglomeration, and improve the cohesiveness of the fly ash in order to improve the collection efficiency of an ESP. Two of the main factors that determine the resistivity are the sulfur content of the coal and the elemental composition of the ash. Low amounts of sulfur in the coal will limit the concentration of sulfur dioxide in the flue gas and thus the extent of its oxidation to sulfur trioxide. The low sulfur PRB coal limits the amount of available sulfur trioxide and water vapor that can be absorbed on a non-conductive fly ash particle, which would lower the resistivity of the fly ash. The low sulfur content and the high alkaline ash both contribute to high resistivity. The low sulfur content limits the amount of sulfur trioxide that is formed while the calcium oxide will preferentially react with the acid and form a non-conducting ash.

The most common types of flue gas conditioning systems for this application include humidification of the flue gas, sulfur trioxide injection, ammonia injection, or a combination of these conditioning methods. Humidification of the flue gas was one of the first methods used to lower the resistivity of the fly ash. However, many of these systems have been replaced with sulfur trioxide and/or ammonia conditioning systems. It is common for facilities with flue gas conditioning systems to utilize sulfur trioxide and/or ammonia injection. Ammonia injection is typically used in retrofits where an existing ESP is undersized and sulfur trioxide alone is not able to effectively reduce the resistivity. However, if sulfur trioxide can effectively reduce the resistivity, then ammonia injection and thus ammonia storage on-site is avoided. Switching to a fuel such as PRB and adding a flue gas conditioning system to achieve lower PM emission rates will achieve significant PM emission reductions assuming that the control efficiency of the existing ESP can be restored.

## **C2.0 FABRIC FILTER (FF)**

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF) unit consists of isolatable compartments with common inlet and outlet manifolds containing rows of fabric filter bags. The filter bags are made from a synthetic felted material that are suspended from a tube sheet mounted at the top of each fabric filter compartment. The tube sheet separates the particulate laden flue gas from the clean flue gas. This tube sheet is a flat sheet of carbon steel with holes designed to accommodate filter bags through which the bags are hung. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside, up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags, and the cleaned gas stream passes through the fabric filter and on to the chimney. A long narrow wire cage is located within the bag to prevent collapse of the bag as the flue gas passes through it. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and then falls into a hopper for storage and subsequent disposal.

Cleaning is either initiated at a preset differential pressure across the tubesheet or based on a maximum time between cleanings. Bags in a PJFF are cleaned by directing a pulse of pressurized air down the filter bag countercurrent to the flue gas flow to induce a traveling ripple (pulse) in the filter bag. This pulse travels the length of the bag, deflecting the bag outward and separating the dust cake as it moves.

An advantage of a fabric filter over an ESP is that a fabric filter is not dependent on the resistivity of the fly ash. Since the fabric filter uses bags instead of an electric charge to remove the particles, the resistivity of the particles is not an issue. Fabric filters also have a lower dependence on particle size than ESPs. A disadvantage of fabric filters is that they have a tendency to corrode and clog with high sulfur coal applications. The high sulfur coals produce more  $\text{SO}_3$ , which tends to create problems with the fabric filters. Therefore, ESPs are typically used on high sulfur coal applications instead of fabric filters. Another disadvantage of fabric filters is the associated pressure drop. The bags, which collect a cake of particles, create an obstruction to the gas path. Fabric filters typically have approximately three times the pressure drop of an ESP. Fabric filters have been proven to control PM removal efficiency in excess of 99%.

### **C3.0ELECTROSTATIC PRECIPITATOR (ESP)**

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. A rapper or hammer system will be utilized to vibrate the collected particles off of the plates so they can fall into the hoppers for storage and subsequent disposal.

The advantages of an ESP include the fact that an ESP can be applied to high sulfur coals, and the pressure drop across an ESP is relatively low compared to other alternatives such as a fabric filter. Unlike the fabric filter, which uses bags as the filter media, an ESP does not contain elements that can plug in the presence of  $\text{SO}_3$ . The unobstructed design of the ESP results in a pressure drop that is approximately 1/3 of a corresponding fabric filter. The disadvantage of the ESP is that its effectiveness to remove particulate is dependant on the resistivity of the fly ash and particle size. ESPs have been proven to control PM removal efficiency in excess of 99%.

## **APPENDIX D**

### **Visibility Modeling and Impairment Improvement Analysis Details (D1)**

Emission Parameters for Basin Electric Power Cooperative BART Modeling Analysis Leland Olds Station Unit 1 & Unit 2												
Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO <sub>2</sub>	NO <sub>x</sub>	PM Fine	PM Coarse
<b>Precontrol</b>												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	350.6	450.00	5970	813	16.5	138.7
Unit 2	500	152.4	22.00	6.71	82.00	25.00	348	448.60	12205	3959	26.9	226.3
<b>Run 1</b>												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	905	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	343.7	NA	NA
Unit1pm	350	106.7	17.4	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
<b>Run 2</b>												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	633.5	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	1359.5	NA	NA
Unit1pm	350	106.7	17.4	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
<b>Run 3</b>												
Unit 1	500	152.4	18.60	5.67	55.00	16.77	144	335.22	452.5	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	1559.5	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22.00	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
<b>Run 4</b>												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	905	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	2462	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	45.6	383
<b>Run 5</b>												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	633.5	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	NA	NA	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	NA	NA
<b>Run 6</b>												
Unit 1	500	152.4	18.60	5.67	55.00	16.77	144	335.22	452.5	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55	16.77	144	335.22	NA	NA	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	NA	NA

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Screening Analysis 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.037	7.271	2.234	2000	74	48	102	2.8	69.68	30.17	0.10	0.06
98th %tile Delta-DV	1.781	4.036	2.255	2000	11	51	105	2.9	55.70	44.09	0.12	0.09
90th %tile Delta-DV	0.449	2.577	2.127	2000	109	49	103	2.3	20.47	78.45	0.86	0.22
2001												
Largest Delta-DV	2.644	4.878	2.234	2001	64	52	106	2.8	88.34	11.50	0.12	0.04
98th %tile Delta-DV	1.286	3.392	2.106	2001	257	51	105	2.2	90.00	9.20	0.64	0.16
90th %tile Delta-DV	0.300	2.534	2.234	2001	43	52	106	2.8	86.90	12.90	0.11	0.08
2002												
Largest Delta-DV	5.618	7.851	2.234	2002	73	51	105	2.8	83.93	15.71	0.27	0.09
98th %tile Delta-DV	2.539	4.645	2.106	2002	233	53	107	2.2	90.14	9.39	0.36	0.11
90th %tile Delta-DV	0.519	2.752	2.234	2002	49	54	108	2.8	69.19	29.93	0.65	0.23
TRNP NORTH UNIT												
2000												
Largest Delta-DV	5.165	7.398	2.234	2000	36	82	71	2.8	52.34	47.24	0.30	0.13
98th %tile Delta-DV	2.175	4.408	2.234	2000	44	71	60	2.8	43.57	55.98	0.34	0.11
90th %tile Delta-DV	0.417	2.545	2.127	2000	137	82	71	2.3	83.17	16.58	0.18	0.07
2001												
Largest Delta-DV	3.847	6.102	2.255	2001	12	83	112	2.9	88.87	10.65	0.38	0.10
98th %tile Delta-DV	1.793	3.899	2.106	2001	260	86	115	2.2	97.10	2.52	0.29	0.09
90th %tile Delta-DV	0.464	2.634	2.170	2001	179	83	112	2.5	94.92	4.81	0.20	0.08
2002												
Largest Delta-DV	6.414	8.647	2.234	2002	73	89	118	2.8	79.45	19.99	0.45	0.11
98th %tile Delta-DV	2.047	4.195	2.149	2002	199	71	60	2.4	89.35	8.85	1.49	0.32
90th %tile Delta-DV	0.468	2.638	2.170	2002	178	83	112	2.5	97.10	2.47	0.34	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	6.000	8.233	2.234	2000	74	90	72	2.8	72.72	27.12	0.10	0.06
98th %tile Delta-DV	1.123	3.250	2.127	2000	110	90	72	2.3	9.98	88.97	0.83	0.22
90th %tile Delta-DV	0.371	2.647	2.276	2000	336	90	72	3	39.36	60.09	0.44	0.11
2001												
Largest Delta-DV	2.647	4.881	2.234	2001	64	90	72	2.8	88.72	11.12	0.12	0.04
98th %tile Delta-DV	1.046	3.322	2.276	2001	328	90	72	3	87.82	12.04	0.09	0.05
90th %tile Delta-DV	0.211	2.445	2.234	2001	55	90	72	2.8	80.67	19.16	0.10	0.08
2002												
Largest Delta-DV	6.145	8.379	2.234	2002	73	90	72	2.8	82.04	17.55	0.32	0.09
98th %tile Delta-DV	1.999	4.233	2.234	2002	39	90	72	2.8	85.12	14.37	0.34	0.17
90th %tile Delta-DV	0.278	2.511	2.234	2002	67	90	72	2.8	61.92	36.64	1.15	0.29
LOSTWOOD NWA												
2000												
Largest Delta-DV	6.396	8.672	2.275	2000	47	97	79	2.9	89.84	9.92	0.17	0.07
98th %tile Delta-DV	1.974	4.249	2.275	2000	88	93	75	2.9	18.46	80.97	0.40	0.16
90th %tile Delta-DV	0.883	3.093	2.211	2000	171	91	73	2.6	16.34	82.87	0.59	0.21
2001												
Largest Delta-DV	7.362	9.702	2.340	2001	326	91	73	3.2	92.10	7.54	0.27	0.09
98th %tile Delta-DV	2.018	4.314	2.297	2001	12	91	73	3	86.63	13.08	0.24	0.05
90th %tile Delta-DV	0.557	2.724	2.167	2001	235	99	81	2.4	64.88	31.34	2.99	0.79
2002												
Largest Delta-DV	3.736	6.011	2.275	2002	74	97	79	2.9	86.44	13.35	0.15	0.06
98th %tile Delta-DV	1.774	4.070	2.297	2002	29	97	79	3	83.32	16.39	0.23	0.07
90th %tile Delta-DV	0.476	2.816	2.340	2002	362	99	81	3.2	83.91	15.88	0.17	0.04

Duration Events

TRNP SOUTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 34  
Number of days with Delta-Deciview > 1.00: 18  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2001  
Number of days with Delta-Deciview > 0.50: 29  
Number of days with Delta-Deciview > 1.00: 10  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2002  
Number of days with Delta-Deciview > 0.50: 37  
Number of days with Delta-Deciview > 1.00: 21  
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH

2000  
Number of days with Delta-Deciview > 0.50: 25  
Number of days with Delta-Deciview > 1.00: 10  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2001  
Number of days with Delta-Deciview > 0.50: 20  
Number of days with Delta-Deciview > 1.00: 9  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2002  
Number of days with Delta-Deciview > 0.50: 26  
Number of days with Delta-Deciview > 1.00: 13  
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 32  
Number of days with Delta-Deciview > 1.00: 16  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2001  
Number of days with Delta-Deciview > 0.50: 34  
Number of days with Delta-Deciview > 1.00: 19  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2002  
Number of days with Delta-Deciview > 0.50: 33  
Number of days with Delta-Deciview > 1.00: 20  
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA

2000  
Number of days with Delta-Deciview > 0.50: 57  
Number of days with Delta-Deciview > 1.00: 31  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2001  
Number of days with Delta-Deciview > 0.50: 39  
Number of days with Delta-Deciview > 1.00: 24  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2002  
Number of days with Delta-Deciview > 0.50: 34  
Number of days with Delta-Deciview > 1.00: 21  
Max number of consecutive days with Delta-Deciview > 0.50: 4

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run 1 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.402	3.636	2.234	2000	74	48	102	2.8	51.80	47.22	0.62	0.35
98th %tile Delta-DV	0.401	2.677	2.276	2000	335	53	107	3	37.54	58.33	3.32	0.81
90th %tile Delta-DV	0.096	2.224	2.127	2000	287	46	46	2.3	59.13	38.53	1.70	0.64
2001												
Largest Delta-DV	0.777	2.883	2.106	2001	258	4	4	2.2	28.15	66.77	4.20	0.87
98th %tile Delta-DV	0.393	2.521	2.127	2001	92	51	105	2.3	33.42	64.26	1.75	0.57
90th %tile Delta-DV	0.091	2.197	2.106	2001	266	4	4	2.2	14.12	83.42	2.02	0.44
2002												
Largest Delta-DV	1.972	4.206	2.234	2002	73	49	103	2.8	44.52	53.78	1.27	0.43
98th %tile Delta-DV	0.832	3.066	2.234	2002	67	28	28	2.8	15.25	80.25	3.71	0.79
90th %tile Delta-DV	0.133	2.239	2.106	2002	240	51	105	2.2	88.91	9.47	1.23	0.39
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.581	3.815	2.234	2000	36	82	71	2.8	34.54	63.12	1.65	0.69
98th %tile Delta-DV	0.563	2.690	2.127	2000	98	84	113	2.3	26.41	69.82	3.05	0.72
90th %tile Delta-DV	0.109	2.215	2.106	2000	265	67	56	2.2	52.96	44.45	1.89	0.70
2001												
Largest Delta-DV	1.704	3.959	2.255	2001	12	83	112	2.9	50.99	47.26	1.39	0.36
98th %tile Delta-DV	0.470	2.598	2.127	2001	112	85	114	2.3	32.47	63.23	3.56	0.73
90th %tile Delta-DV	0.110	2.343	2.234	2001	89	82	71	2.8	52.71	46.43	0.49	0.38
2002												
Largest Delta-DV	2.733	4.967	2.234	2002	73	89	118	2.8	37.20	60.56	1.79	0.45
98th %tile Delta-DV	0.720	2.954	2.234	2002	83	71	60	2.8	24.29	71.93	2.90	0.88
90th %tile Delta-DV	0.135	2.390	2.255	2002	30	82	71	2.9	53.65	45.76	0.36	0.24
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.695	3.928	2.234	2000	74	90	72	2.8	53.38	45.66	0.59	0.37
98th %tile Delta-DV	0.378	2.484	2.106	2000	247	90	72	2.2	86.21	8.52	4.17	1.11
90th %tile Delta-DV	0.087	2.321	2.234	2000	71	90	72	2.8	38.89	58.89	1.69	0.54
2001												
Largest Delta-DV	0.767	3.022	2.255	2001	12	90	72	2.9	50.46	49.03	0.36	0.15
98th %tile Delta-DV	0.328	2.561	2.234	2001	84	90	72	2.8	39.77	58.04	1.65	0.54
90th %tile Delta-DV	0.059	2.186	2.127	2001	98	90	72	2.3	15.65	81.71	2.12	0.52
2002												
Largest Delta-DV	2.340	4.573	2.234	2002	73	90	72	2.8	41.70	56.46	1.43	0.42
98th %tile Delta-DV	0.670	2.904	2.234	2002	39	90	72	2.8	45.10	52.61	1.51	0.78
90th %tile Delta-DV	0.094	2.200	2.106	2002	241	90	72	2.2	89.44	9.32	0.90	0.34
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.293	4.569	2.275	2000	47	97	79	2.9	49.48	49.36	0.82	0.34
98th %tile Delta-DV	0.433	2.600	2.167	2000	217	93	75	2.4	74.23	19.53	4.95	1.29
90th %tile Delta-DV	0.169	2.401	2.232	2000	197	99	81	2.7	20.47	76.51	2.13	0.88
2001												
Largest Delta-DV	2.532	4.872	2.340	2001	326	91	73	3.2	51.00	47.13	1.41	0.46
98th %tile Delta-DV	0.650	2.926	2.275	2001	41	91	73	2.9	39.94	58.48	1.10	0.47
90th %tile Delta-DV	0.218	2.363	2.145	2001	270	99	81	2.3	24.10	68.90	5.62	1.38
2002												
Largest Delta-DV	1.117	3.392	2.275	2002	74	97	79	2.9	50.35	48.49	0.82	0.34
98th %tile Delta-DV	0.544	2.883	2.340	2002	363	97	79	3.2	43.82	55.42	0.51	0.25
90th %tile Delta-DV	0.127	2.294	2.167	2002	234	97	79	2.4	77.90	17.85	3.00	1.24

Duration Events

TRNP SOUTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 15  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP ELKHORN RANCH

2000  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 2  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 10  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 8  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 7  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 13  
 Number of days with Delta-Deciview > 1.00: 4  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
 Number of days with Delta-Deciview > 0.50: 5  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 11  
 Number of days with Delta-Deciview > 1.00: 5  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 8  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run2 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ	ND	% of Modeled Extinction by Species				
						RECEP	RECEP	F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.197	3.430	2.234	2000	74	48	102	2.8	42.93	55.92	0.73	0.42
98th %tile Delta-DV	0.357	2.632	2.276	2000	335	53	107	3.0	29.60	65.74	3.75	0.91
90th %tile Delta-DV	0.082	2.231	2.149	2000	199	53	107	2.4	61.89	27.55	8.29	2.28
2001												
Largest Delta-DV	0.715	2.821	2.106	2001	258	36	36	2.2	18.57	75.76	4.70	0.97
98th %tile Delta-DV	0.355	2.482	2.127	2001	92	51	105	2.3	26.00	71.42	1.94	0.63
90th %tile Delta-DV	0.072	2.178	2.106	2001	230	45	45	2.2	20.18	72.24	6.24	1.33
2002												
Largest Delta-DV	1.731	3.964	2.234	2002	73	49	103	2.8	35.96	62.08	1.47	0.49
98th %tile Delta-DV	0.796	3.029	2.234	2002	67	28	28	2.8	11.19	84.09	3.89	0.83
90th %tile Delta-DV	0.110	2.216	2.106	2002	220	51	105	2.2	55.28	43.10	1.03	0.60
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.429	3.663	2.234	2000	36	82	71	2.8	26.96	70.43	1.83	0.77
98th %tile Delta-DV	0.496	2.602	2.106	2000	247	82	71	2.2	32.53	62.98	3.35	1.13
90th %tile Delta-DV	0.092	2.198	2.106	2000	265	67	56	2.2	44.05	52.87	2.25	0.84
2001												
Largest Delta-DV	1.462	3.717	2.255	2001	12	83	112	2.9	42.12	55.81	1.64	0.42
98th %tile Delta-DV	0.426	2.553	2.127	2001	112	85	114	2.3	25.18	70.07	3.94	0.81
90th %tile Delta-DV	0.102	2.230	2.127	2001	302	68	57	2.3	15.59	77.64	5.52	1.25
2002												
Largest Delta-DV	2.463	4.697	2.234	2002	73	89	118	2.8	29.30	68.18	2.02	0.50
98th %tile Delta-DV	0.670	2.903	2.234	2002	83	71	60	2.8	18.34	77.58	3.13	0.95
90th %tile Delta-DV	0.114	2.284	2.170	2002	155	82	71	2.5	51.04	48.31	0.39	0.26
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.442	3.675	2.234	2000	74	90	72	2.8	44.48	54.37	0.71	0.44
98th %tile Delta-DV	0.282	2.388	2.106	2000	247	90	72	2.2	81.19	11.72	5.61	1.49
90th %tile Delta-DV	0.070	2.303	2.234	2000	56	90	72	2.8	39.56	58.69	1.27	0.48
2001												
Largest Delta-DV	0.655	2.909	2.255	2001	12	90	72	2.9	41.62	57.78	0.42	0.17
98th %tile Delta-DV	0.272	2.378	2.106	2001	260	90	72	2.2	73.47	22.63	2.98	0.92
90th %tile Delta-DV	0.045	2.194	2.149	2001	195	90	72	2.4	86.34	11.45	1.57	0.64
2002												
Largest Delta-DV	2.076	4.309	2.234	2002	73	90	72	2.8	33.35	64.54	1.63	0.48
98th %tile Delta-DV	0.584	2.817	2.234	2002	39	90	72	2.8	36.43	60.94	1.74	0.90
90th %tile Delta-DV	0.081	2.187	2.106	2002	220	90	72	2.2	71.39	26.20	1.47	0.94
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.985	4.261	2.275	2000	47	97	79	2.9	40.66	57.98	0.96	0.40
98th %tile Delta-DV	0.380	2.677	2.297	2000	14	91	73	3.0	30.00	67.46	2.01	0.54
90th %tile Delta-DV	0.147	2.293	2.145	2000	137	91	73	2.3	33.90	61.77	3.45	0.89
2001												
Largest Delta-DV	2.187	4.527	2.340	2001	326	91	73	3.2	42.08	55.71	1.66	0.55
98th %tile Delta-DV	0.575	2.850	2.275	2001	41	91	73	2.9	31.76	66.45	1.25	0.53
90th %tile Delta-DV	0.191	2.530	2.340	2001	345	99	81	3.2	17.54	78.59	3.04	0.83
2002												
Largest Delta-DV	1.005	3.345	2.340	2002	337	91	73	3.2	10.12	86.30	2.46	1.12
98th %tile Delta-DV	0.474	2.814	2.340	2002	363	97	79	3.2	35.32	63.81	0.58	0.29
90th %tile Delta-DV	0.110	2.320	2.211	2002	178	97	79	2.6	76.02	19.82	3.34	0.81

Duration Events

TRNP SOUTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2002  
Number of days with Delta-Deciview > 0.50: 15  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 7  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 12  
Number of days with Delta-Deciview > 1.00: 4  
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 2  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 8  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA

2000  
Number of days with Delta-Deciview > 0.50: 5  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 11  
Number of days with Delta-Deciview > 1.00: 4  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2002  
Number of days with Delta-Deciview > 0.50: 6  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run 3 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	0.973	3.207	2.234	2000	72	6	6	2.8	23.24	74.15	2.00	0.61
98th %tile Delta-DV	0.298	2.553	2.255	2000	11	51	105	2.9	24.70	73.57	1.01	0.72
90th %tile Delta-DV	0.073	2.200	2.127	2000	287	46	46	2.3	41.38	55.53	2.25	0.85
2001												
Largest Delta-DV	0.513	2.747	2.234	2001	64	46	46	2.8	37.89	60.81	0.95	0.35
98th %tile Delta-DV	0.276	2.552	2.276	2001	338	48	102	3.0	20.29	74.19	4.22	1.31
90th %tile Delta-DV	0.060	2.208	2.149	2001	211	53	107	2.4	78.75	13.84	5.46	1.96
2002												
Largest Delta-DV	1.538	3.771	2.234	2002	78	46	46	2.8	27.91	70.28	1.24	0.57
98th %tile Delta-DV	0.627	2.903	2.276	2002	336	53	107	3.0	9.57	86.23	3.40	0.81
90th %tile Delta-DV	0.124	2.251	2.127	2002	105	45	45	2.3	10.64	83.47	4.43	1.46
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.215	3.449	2.234	2000	36	82	71	2.8	20.96	75.94	2.18	0.92
98th %tile Delta-DV	0.309	2.415	2.106	2000	247	71	60	2.2	35.55	56.75	5.78	1.92
90th %tile Delta-DV	0.066	2.321	2.255	2000	31	85	114	2.9	22.89	74.75	1.71	0.66
2001												
Largest Delta-DV	0.904	3.158	2.255	2001	12	83	112	2.9	35.10	61.46	2.74	0.71
98th %tile Delta-DV	0.336	2.569	2.234	2001	63	82	71	2.8	48.08	50.81	0.74	0.37
90th %tile Delta-DV	0.085	2.255	2.170	2001	175	82	71	2.5	76.76	8.28	12.02	2.94
2002												
Largest Delta-DV	2.003	4.236	2.234	2002	73	89	118	2.8	23.59	73.24	2.54	0.63
98th %tile Delta-DV	0.569	2.844	2.276	2002	337	58	47	3.0	20.45	77.66	1.29	0.60
90th %tile Delta-DV	0.092	2.219	2.127	2002	110	82	71	2.3	38.92	58.39	2.10	0.60
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.131	3.365	2.234	2000	74	90	72	2.8	36.53	61.99	0.92	0.56
98th %tile Delta-DV	0.210	2.316	2.106	2000	247	90	72	2.2	76.34	14.06	7.58	2.01
90th %tile Delta-DV	0.062	2.295	2.234	2000	47	90	72	2.8	33.95	65.44	0.28	0.33
2001												
Largest Delta-DV	0.506	2.739	2.234	2001	64	90	72	2.8	38.81	59.87	0.98	0.34
98th %tile Delta-DV	0.215	2.321	2.106	2001	260	90	72	2.2	66.03	29.01	3.78	1.17
90th %tile Delta-DV	0.034	2.161	2.127	2001	99	90	72	2.3	43.07	55.86	0.56	0.52
2002												
Largest Delta-DV	1.759	3.993	2.234	2002	73	90	72	2.8	26.76	70.71	1.96	0.57
98th %tile Delta-DV	0.472	2.706	2.234	2002	39	90	72	2.8	28.72	68.00	2.16	1.12
90th %tile Delta-DV	0.066	2.172	2.106	2002	220	90	72	2.2	64.25	32.77	1.82	1.16
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.732	4.007	2.275	2000	47	97	79	2.9	32.48	65.94	1.12	0.46
98th %tile Delta-DV	0.349	2.624	2.275	2000	72	97	79	2.9	32.04	66.53	1.07	0.36
90th %tile Delta-DV	0.125	2.292	2.167	2000	239	93	75	2.4	37.43	54.55	6.16	1.85
2001												
Largest Delta-DV	2.009	4.348	2.340	2001	326	91	73	3.2	35.26	62.31	1.83	0.60
98th %tile Delta-DV	0.511	2.786	2.275	2001	41	91	73	2.9	24.59	73.39	1.42	0.60
90th %tile Delta-DV	0.136	2.476	2.340	2001	345	93	75	3.2	13.72	80.86	4.29	1.14
2002												
Largest Delta-DV	0.999	3.338	2.340	2002	337	93	75	3.2	7.42	88.97	2.46	1.14
98th %tile Delta-DV	0.396	2.736	2.340	2002	363	93	75	3.2	28.29	70.67	0.69	0.35
90th %tile Delta-DV	0.098	2.330	2.232	2002	188	97	79	2.7	30.17	57.49	9.75	2.58

Duration Events

TRNP SOUTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 1  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 13  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP ELKHORN RANCH

2000  
Number of days with Delta-Deciview > 0.50: 2  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 1  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 7  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 10  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 8  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2002  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run 4 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ	ND	% of Modeled Extinction by Species				
						RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.272	3.505	2.234	2000	74	48	102	2.8	57.50	41.42	0.69	0.39
98th %tile Delta-DV	0.354	2.629	2.276	2000	335	53	107	3	42.66	52.64	3.78	0.92
90th %tile Delta-DV	0.089	2.216	2.127	2000	287	46	46	2.3	64.25	33.20	1.85	0.70
2001												
Largest Delta-DV	0.673	2.779	2.106	2001	258	4	4	2.2	32.66	61.45	4.88	1.01
98th %tile Delta-DV	0.347	2.581	2.234	2001	63	53	107	2.8	65.68	33.50	0.56	0.25
90th %tile Delta-DV	0.083	2.189	2.106	2001	224	46	46	2.2	88.70	3.24	6.62	1.44
2002												
Largest Delta-DV	1.768	4.001	2.234	2002	73	49	103	2.8	50.20	47.88	1.43	0.48
98th %tile Delta-DV	0.703	2.937	2.234	2002	74	49	103	2.8	54.38	44.15	1.06	0.42
90th %tile Delta-DV	0.126	2.232	2.106	2002	220	51	105	2.2	68.92	29.66	0.90	0.52
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.388	3.622	2.234	2000	36	82	71	2.8	39.73	57.58	1.89	0.80
98th %tile Delta-DV	0.483	2.611	2.127	2000	98	84	113	2.3	30.87	64.72	3.57	0.84
90th %tile Delta-DV	0.097	2.224	2.127	2000	101	82	71	2.3	46.88	49.15	3.06	0.90
2001												
Largest Delta-DV	1.549	3.804	2.255	2001	12	83	112	2.9	56.55	41.51	1.54	0.40
98th %tile Delta-DV	0.436	2.542	2.106	2001	258	85	114	2.2	81.70	14.63	2.87	0.80
90th %tile Delta-DV	0.108	2.214	2.106	2001	247	58	47	2.2	87.26	3.01	7.23	2.51
2002												
Largest Delta-DV	2.424	4.658	2.234	2002	73	89	118	2.8	42.63	54.81	2.05	0.51
98th %tile Delta-DV	0.620	2.769	2.149	2002	199	79	68	2.4	58.24	34.62	5.85	1.28
90th %tile Delta-DV	0.127	2.297	2.170	2002	155	82	71	2.5	65.23	34.19	0.35	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.544	3.777	2.234	2000	74	90	72	2.8	59.04	39.89	0.66	0.41
98th %tile Delta-DV	0.372	2.478	2.106	2000	247	90	72	2.2	87.74	6.89	4.24	1.13
90th %tile Delta-DV	0.076	2.310	2.234	2000	71	90	72	2.8	44.47	52.99	1.93	0.61
2001												
Largest Delta-DV	0.691	2.946	2.255	2001	12	90	72	2.9	56.26	43.18	0.40	0.16
98th %tile Delta-DV	0.295	2.422	2.127	2001	112	90	72	2.3	42.86	53.15	3.28	0.70
90th %tile Delta-DV	0.053	2.329	2.276	2001	310	90	72	3	38.28	57.72	2.33	1.67
2002												
Largest Delta-DV	2.089	4.323	2.234	2002	73	90	72	2.8	47.31	50.60	1.62	0.47
98th %tile Delta-DV	0.601	2.834	2.234	2002	39	90	72	2.8	50.50	46.94	1.69	0.87
90th %tile Delta-DV	0.089	2.259	2.170	2002	178	90	72	2.5	79.36	17.37	2.52	0.74
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.077	4.352	2.275	2000	47	97	79	2.9	55.26	43.45	0.92	0.38
98th %tile Delta-DV	0.391	2.666	2.275	2000	72	97	79	2.9	54.51	44.22	0.95	0.32
90th %tile Delta-DV	0.150	2.382	2.232	2000	192	99	81	2.7	57.00	37.60	4.35	1.06
2001												
Largest Delta-DV	2.312	4.651	2.340	2001	326	91	73	3.2	56.50	41.42	1.56	0.51
98th %tile Delta-DV	0.572	2.847	2.275	2001	41	91	73	2.9	45.61	52.60	1.26	0.54
90th %tile Delta-DV	0.187	2.333	2.145	2001	270	99	81	2.3	28.08	63.76	6.55	1.61
2002												
Largest Delta-DV	1.007	3.283	2.275	2002	74	97	79	2.9	56.13	42.58	0.91	0.38
98th %tile Delta-DV	0.482	2.822	2.340	2002	363	97	79	3.2	49.57	49.57	0.57	0.29
90th %tile Delta-DV	0.122	2.289	2.167	2002	234	97	79	2.4	81.01	14.57	3.12	1.29

Duration Events

TRNP SOUTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 3  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 15  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP ELKHORN RANCH

2000  
 Number of days with Delta-Deciview > 0.50: 3  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 2  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 9  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 6  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 11  
 Number of days with Delta-Deciview > 1.00: 4  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
 Number of days with Delta-Deciview > 0.50: 5  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 11  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 6  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run 5 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.064	3.297	2.234	2000	74	48	102	2.8	48.64	50.06	0.83	0.48
98th %tile Delta-DV	0.309	2.585	2.276	2000	335	53	107	3	34.24	60.37	4.33	1.06
90th %tile Delta-DV	0.073	2.200	2.127	2000	109	50	104	2.3	14.74	76.32	7.05	1.89
2001												
Largest Delta-DV	0.609	2.715	2.106	2001	258	4	4	2.2	25.34	68.13	5.40	1.12
98th %tile Delta-DV	0.300	2.428	2.127	2001	92	51	105	2.3	30.79	66.15	2.30	0.75
90th %tile Delta-DV	0.068	2.217	2.149	2001	195	46	46	2.4	82.05	15.28	1.98	0.69
2002												
Largest Delta-DV	1.521	3.754	2.234	2002	73	49	103	2.8	41.37	56.38	1.69	0.57
98th %tile Delta-DV	0.662	2.895	2.234	2002	67	28	28	2.8	13.55	80.74	4.71	1.01
90th %tile Delta-DV	0.100	2.206	2.106	2002	220	51	105	2.2	60.81	37.40	1.13	0.66
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.233	3.467	2.234	2000	36	82	71	2.8	31.56	65.39	2.15	0.90
98th %tile Delta-DV	0.433	2.539	2.106	2000	247	82	71	2.2	37.39	57.45	3.85	1.30
90th %tile Delta-DV	0.082	2.188	2.106	2000	265	67	56	2.2	49.44	47.10	2.52	0.94
2001												
Largest Delta-DV	1.303	3.558	2.255	2001	12	83	112	2.9	47.65	50.01	1.86	0.48
98th %tile Delta-DV	0.365	2.493	2.127	2001	112	85	114	2.3	29.44	65.00	4.61	0.95
90th %tile Delta-DV	0.086	2.213	2.127	2001	302	68	57	2.3	18.55	73.40	6.57	1.48
2002												
Largest Delta-DV	2.145	4.379	2.234	2002	73	89	118	2.8	34.21	62.85	2.35	0.59
98th %tile Delta-DV	0.565	2.798	2.234	2002	83	71	60	2.8	21.87	73.27	3.73	1.13
90th %tile Delta-DV	0.101	2.355	2.255	2002	30	82	71	2.9	50.48	48.72	0.48	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.287	3.521	2.234	2000	74	90	72	2.8	50.22	48.49	0.80	0.49
98th %tile Delta-DV	0.276	2.382	2.106	2000	247	90	72	2.2	83.19	9.54	5.74	1.53
90th %tile Delta-DV	0.062	2.211	2.149	2000	187	90	72	2.4	93.17	2.98	2.79	1.05
2001												
Largest Delta-DV	0.578	2.832	2.255	2001	12	90	72	2.9	47.37	51.96	0.48	0.20
98th %tile Delta-DV	0.249	2.483	2.234	2001	84	90	72	2.8	36.75	60.36	2.18	0.71
90th %tile Delta-DV	0.043	2.277	2.234	2001	82	90	72	2.8	51.20	46.79	1.44	0.58
2002												
Largest Delta-DV	1.818	4.052	2.234	2002	73	90	72	2.8	38.58	58.98	1.89	0.55
98th %tile Delta-DV	0.513	2.747	2.234	2002	39	90	72	2.8	41.58	55.41	1.98	1.03
90th %tile Delta-DV	0.074	2.202	2.127	2002	128	90	72	2.3	11.49	80.11	6.60	1.80
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.761	4.037	2.275	2000	47	97	79	2.9	46.35	52.09	1.10	0.45
98th %tile Delta-DV	0.328	2.603	2.275	2000	72	97	79	2.9	45.61	52.86	1.14	0.38
90th %tile Delta-DV	0.129	2.275	2.145	2000	98	91	73	2.3	37.69	59.14	2.38	0.78
2001												
Largest Delta-DV	1.958	4.298	2.340	2001	326	91	73	3.2	47.56	49.94	1.88	0.62
98th %tile Delta-DV	0.496	2.771	2.275	2001	41	91	73	2.9	36.99	60.93	1.46	0.62
90th %tile Delta-DV	0.170	2.315	2.145	2001	117	99	81	2.3	20.42	74.99	2.08	2.51
2002												
Largest Delta-DV	0.845	3.120	2.275	2002	74	97	79	2.9	47.24	51.21	1.09	0.46
98th %tile Delta-DV	0.412	2.752	2.340	2002	363	97	79	3.2	40.76	58.23	0.67	0.34
90th %tile Delta-DV	0.098	2.244	2.145	2002	134	97	79	2.3	14.60	75.52	7.69	2.19

Duration Events

TRNP SOUTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 13  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP ELKHORN RANCH

2000  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 2  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 8  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 10  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 7  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2002  
Number of days with Delta-Deciview > 0.50: 4  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 1 BART Run 6 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ	ND	% of Modeled Extinction by Species				
						RECEP	RECEP	F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	0.825	3.059	2.234	2000	72	6	6	2.8	27.61	69.29	2.38	0.72
98th %tile Delta-DV	0.253	2.508	2.255	2000	11	51	105	2.9	29.15	68.81	1.20	0.85
90th %tile Delta-DV	0.065	2.214	2.149	2000	187	45	45	2.4	82.68	12.97	3.22	1.13
2001												
Largest Delta-DV	0.448	2.682	2.234	2001	64	46	46	2.8	43.50	55.00	1.10	0.40
98th %tile Delta-DV	0.249	2.355	2.106	2001	260	52	106	2.2	65.57	29.07	4.17	1.20
90th %tile Delta-DV	0.054	2.329	2.276	2001	310	53	107	3	29.20	66.04	2.78	1.98
2002												
Largest Delta-DV	1.325	3.559	2.234	2002	78	46	46	2.8	32.75	65.12	1.46	0.66
98th %tile Delta-DV	0.524	2.652	2.127	2002	136	53	107	2.3	17.26	72.95	7.90	1.89
90th %tile Delta-DV	0.102	2.230	2.127	2002	105	45	45	2.3	12.90	79.96	5.37	1.77
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.034	3.267	2.234	2000	36	82	71	2.8	24.87	71.45	2.59	1.09
98th %tile Delta-DV	0.273	2.379	2.106	2000	247	71	60	2.2	40.25	51.03	6.55	2.17
90th %tile Delta-DV	0.057	2.227	2.170	2000	165	58	47	2.5	50.04	46.35	2.61	1.00
2001												
Largest Delta-DV	0.793	3.047	2.255	2001	12	83	112	2.9	40.24	55.81	3.14	0.81
98th %tile Delta-DV	0.299	2.532	2.234	2001	63	82	71	2.8	54.15	44.60	0.83	0.42
90th %tile Delta-DV	0.077	2.311	2.234	2001	85	84	113	2.8	15.75	79.66	3.59	1.00
2002												
Largest Delta-DV	1.718	3.952	2.234	2002	73	89	118	2.8	27.90	68.35	3.00	0.75
98th %tile Delta-DV	0.479	2.755	2.276	2002	337	58	47	3	24.39	73.36	1.54	0.72
90th %tile Delta-DV	0.081	2.208	2.127	2002	110	82	71	2.3	44.43	52.49	2.39	0.68
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	0.991	3.224	2.234	2000	74	90	72	2.8	42.00	56.29	1.05	0.65
98th %tile Delta-DV	0.204	2.310	2.106	2000	247	90	72	2.2	78.62	11.51	7.80	2.07
90th %tile Delta-DV	0.054	2.287	2.234	2000	36	90	72	2.8	24.77	72.98	1.53	0.72
2001												
Largest Delta-DV	0.443	2.676	2.234	2001	64	90	72	2.8	44.47	54.02	1.12	0.39
98th %tile Delta-DV	0.202	2.308	2.106	2001	260	90	72	2.2	70.31	24.41	4.03	1.25
90th %tile Delta-DV	0.030	2.179	2.149	2001	190	90	72	2.4	87.28	2.25	8.24	2.24
2002												
Largest Delta-DV	1.516	3.750	2.234	2002	73	90	72	2.8	31.44	65.59	2.30	0.67
98th %tile Delta-DV	0.408	2.642	2.234	2002	39	90	72	2.8	33.34	62.86	2.51	1.30
90th %tile Delta-DV	0.061	2.209	2.149	2002	189	90	72	2.4	81.52	6.96	8.88	2.64
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.506	3.782	2.275	2000	47	97	79	2.9	37.77	60.39	1.30	0.54
98th %tile Delta-DV	0.300	2.576	2.275	2000	72	97	79	2.9	37.30	61.04	1.24	0.42
90th %tile Delta-DV	0.111	2.278	2.167	2000	239	93	75	2.4	42.23	48.73	6.95	2.09
2001												
Largest Delta-DV	1.772	4.112	2.340	2001	326	91	73	3.2	40.47	56.74	2.10	0.69
98th %tile Delta-DV	0.433	2.708	2.275	2001	41	91	73	2.9	29.12	68.49	1.68	0.71
90th %tile Delta-DV	0.121	2.332	2.211	2001	175	93	75	2.6	86.28	6.19	5.80	1.74
2002												
Largest Delta-DV	0.822	3.162	2.340	2002	337	93	75	3.2	9.10	86.48	3.02	1.40
98th %tile Delta-DV	0.338	2.678	2.340	2002	363	93	75	3.2	33.20	65.58	0.81	0.41
90th %tile Delta-DV	0.082	2.228	2.145	2002	134	99	81	2.3	10.92	77.74	8.74	2.61

Duration Events

TRNP SOUTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 2  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 0  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 0  
 2002  
 Number of days with Delta-Deciview > 0.50: 10  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 3  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 7  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

2000  
 Number of days with Delta-Deciview > 0.50: 2  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 0  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 0  
 2002  
 Number of days with Delta-Deciview > 0.50: 6  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA

2000  
 Number of days with Delta-Deciview > 0.50: 1  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 7  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative Leland Olds Station Unit 2 BART Screening Analysis 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
	-----	-----	-----	----	----	-----	-----	F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.555	7.789	2.234	2000	72	3	3	2.8	64.50	35.23	0.20	0.06
98th %tile Delta-DV	2.340	4.573	2.234	2000	71	45	45	2.8	63.17	36.53	0.23	0.07
90th %tile Delta-DV	0.674	2.780	2.106	2000	217	51	105	2.2	72.89	26.84	0.19	0.08
2001												
Largest Delta-DV	5.384	7.618	2.234	2001	64	46	46	2.8	75.27	24.62	0.08	0.03
98th %tile Delta-DV	2.339	4.466	2.127	2001	92	51	105	2.3	54.75	44.89	0.27	0.09
90th %tile Delta-DV	0.586	2.713	2.127	2001	131	53	107	2.3	65.85	33.92	0.15	0.08
2002												
Largest Delta-DV	9.117	11.351	2.234	2002	73	49	103	2.8	76.50	23.23	0.20	0.06
98th %tile Delta-DV	4.924	7.030	2.106	2002	233	53	107	2.2	81.37	18.31	0.24	0.08
90th %tile Delta-DV	1.161	3.288	2.127	2002	95	46	46	2.3	50.63	48.95	0.31	0.11
TRNP NORTH UNIT												
2000												
Largest Delta-DV	5.115	7.349	2.234	2000	72	82	71	2.8	66.02	33.73	0.20	0.05
98th %tile Delta-DV	2.430	4.705	2.276	2000	316	85	114	3	63.24	36.55	0.17	0.05
90th %tile Delta-DV	0.681	2.787	2.106	2000	238	85	114	2.2	93.64	5.82	0.41	0.13
2001												
Largest Delta-DV	6.501	8.734	2.234	2001	64	82	71	2.8	74.84	25.02	0.10	0.03
98th %tile Delta-DV	2.954	5.209	2.255	2001	12	83	112	2.9	73.21	26.59	0.16	0.04
90th %tile Delta-DV	0.827	3.061	2.234	2001	62	82	71	2.8	80.29	19.62	0.06	0.03
2002												
Largest Delta-DV	9.937	12.170	2.234	2002	73	89	118	2.8	64.99	34.69	0.26	0.06
98th %tile Delta-DV	3.958	6.085	2.127	2002	293	58	47	2.3	69.27	29.98	0.58	0.16
90th %tile Delta-DV	0.761	3.016	2.255	2002	30	82	71	2.9	74.64	25.29	0.05	0.03
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	6.879	9.113	2.234	2000	74	90	72	2.8	84.55	15.32	0.07	0.05
98th %tile Delta-DV	1.581	3.814	2.234	2000	54	90	72	2.8	78.53	21.22	0.19	0.06
90th %tile Delta-DV	0.553	2.680	2.127	2000	101	90	72	2.3	58.05	41.44	0.37	0.14
2001												
Largest Delta-DV	5.192	7.426	2.234	2001	64	90	72	2.8	76.26	23.63	0.08	0.03
98th %tile Delta-DV	2.288	4.521	2.234	2001	84	90	72	2.8	62.27	37.42	0.23	0.07
90th %tile Delta-DV	0.434	2.540	2.106	2001	230	90	72	2.2	87.77	10.96	1.05	0.22
2002												
Largest Delta-DV	9.852	12.086	2.234	2002	73	90	72	2.8	70.69	29.03	0.22	0.06
98th %tile Delta-DV	3.450	5.725	2.276	2002	336	90	72	3	65.33	34.31	0.29	0.06
90th %tile Delta-DV	0.617	2.723	2.106	2002	270	90	72	2.2	52.16	47.06	0.60	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	8.438	10.714	2.275	2000	47	99	81	2.9	95.78	4.03	0.14	0.06
98th %tile Delta-DV	2.419	4.587	2.167	2000	231	93	75	2.4	85.81	13.16	0.76	0.27
90th %tile Delta-DV	1.109	3.342	2.232	2000	209	99	81	2.7	77.75	21.00	0.94	0.31
2001												
Largest Delta-DV	9.179	11.518	2.340	2001	326	99	81	3.2	91.22	8.47	0.24	0.07
98th %tile Delta-DV	4.158	6.303	2.145	2001	261	99	81	2.3	90.60	8.78	0.50	0.12
90th %tile Delta-DV	1.032	3.178	2.145	2001	260	97	79	2.3	87.32	12.53	0.11	0.04
2002												
Largest Delta-DV	6.803	9.078	2.275	2002	74	97	79	2.9	72.69	27.16	0.12	0.04
98th %tile Delta-DV	3.609	5.949	2.340	2002	337	93	75	3.2	33.34	65.90	0.59	0.17
90th %tile Delta-DV	0.796	2.942	2.145	2002	100	91	73	2.3	74.33	25.51	0.10	0.06

Duration Events

TRNP SOUTH UNIT

2000

Number of days with Delta-Deciview > 0.50: 46  
 Number of days with Delta-Deciview > 1.00: 28  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

2001

Number of days with Delta-Deciview > 0.50: 40  
 Number of days with Delta-Deciview > 1.00: 27  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

2002

Number of days with Delta-Deciview > 0.50: 56  
 Number of days with Delta-Deciview > 1.00: 39  
 Max number of consecutive days with Delta-Deciview > 0.50: 5

TRNP NORTH UNIT

2000

Number of days with Delta-Deciview > 0.50: 40  
 Number of days with Delta-Deciview > 1.00: 26  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

2001

Number of days with Delta-Deciview > 0.50: 54  
 Number of days with Delta-Deciview > 1.00: 31  
 Max number of consecutive days with Delta-Deciview > 0.50: 4

2002

Number of days with Delta-Deciview > 0.50: 50  
 Number of days with Delta-Deciview > 1.00: 31  
 Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH

2000

Number of days with Delta-Deciview > 0.50: 39  
 Number of days with Delta-Deciview > 1.00: 19  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

2001

Number of days with Delta-Deciview > 0.50: 33  
 Number of days with Delta-Deciview > 1.00: 17  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

2002

Number of days with Delta-Deciview > 0.50: 45  
 Number of days with Delta-Deciview > 1.00: 25  
 Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA

2000

Number of days with Delta-Deciview > 0.50: 65  
 Number of days with Delta-Deciview > 1.00: 41  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

2001

Number of days with Delta-Deciview > 0.50: 64  
 Number of days with Delta-Deciview > 1.00: 37  
 Max number of consecutive days with Delta-Deciview > 0.50: 6

2002

Number of days with Delta-Deciview > 0.50: 51  
 Number of days with Delta-Deciview > 1.00: 34  
 Max number of consecutive days with Delta-Deciview > 0.50: 4

Basin Electric Power Cooperative Leland Olds Station Unit 2 BART Run 1 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.616	3.850	2.234	2000	72	4	4	2.8	25.56	72.54	1.44	0.46
98th %tile Delta-DV	0.492	2.768	2.276	2000	335	53	107	3.0	29.71	62.67	6.12	1.50
90th %tile Delta-DV	0.124	2.252	2.127	2000	109	7	7	2.3	10.46	85.42	3.12	1.00
2001												
Largest Delta-DV	0.893	3.126	2.234	2001	64	46	46	2.8	39.58	59.07	0.99	0.36
98th %tile Delta-DV	0.484	2.738	2.255	2001	13	6	6	2.9	22.66	73.36	3.22	0.75
90th %tile Delta-DV	0.104	2.252	2.149	2001	195	46	46	2.4	74.42	22.72	2.08	0.78
2002												
Largest Delta-DV	2.526	4.759	2.234	2002	78	46	46	2.8	30.14	68.08	1.22	0.57
98th %tile Delta-DV	0.961	3.195	2.234	2002	74	49	103	2.8	34.66	63.38	1.49	0.48
90th %tile Delta-DV	0.201	2.328	2.127	2002	105	46	46	2.3	11.63	83.74	3.45	1.18
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.472	3.706	2.234	2000	36	82	71	2.8	23.43	75.62	0.69	0.26
98th %tile Delta-DV	0.502	2.778	2.276	2000	316	85	114	3.0	26.09	71.95	1.54	0.42
90th %tile Delta-DV	0.107	2.340	2.234	2000	46	68	57	2.8	7.81	87.77	3.63	0.79
2001												
Largest Delta-DV	1.202	3.436	2.234	2001	64	82	71	2.8	39.09	59.26	1.23	0.41
98th %tile Delta-DV	0.609	2.843	2.234	2001	42	82	71	2.8	36.93	61.83	0.87	0.37
90th %tile Delta-DV	0.132	2.407	2.276	2001	316	82	71	3.0	24.19	74.80	0.75	0.26
2002												
Largest Delta-DV	3.070	5.304	2.234	2002	73	89	118	2.8	26.09	71.35	2.04	0.52
98th %tile Delta-DV	0.991	3.224	2.234	2002	50	71	60	2.8	20.70	76.66	1.97	0.67
90th %tile Delta-DV	0.147	2.253	2.106	2002	241	82	71	2.2	79.82	17.85	1.72	0.62
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.650	3.884	2.234	2000	74	90	72	2.8	39.15	59.66	0.68	0.51
98th %tile Delta-DV	0.334	2.568	2.234	2000	69	90	72	2.8	20.06	76.02	3.13	0.79
90th %tile Delta-DV	0.104	2.274	2.170	2000	152	90	72	2.5	27.73	62.31	7.77	2.19
2001												
Largest Delta-DV	0.859	3.093	2.234	2001	64	90	72	2.8	40.75	57.88	1.01	0.36
98th %tile Delta-DV	0.317	2.571	2.255	2001	12	90	72	2.9	36.15	62.11	1.34	0.39
90th %tile Delta-DV	0.057	2.163	2.106	2001	224	90	72	2.2	85.00	4.89	8.12	1.98
2002												
Largest Delta-DV	2.741	4.974	2.234	2002	73	90	72	2.8	29.16	68.30	1.99	0.55
98th %tile Delta-DV	0.767	3.001	2.234	2002	39	90	72	2.8	31.04	66.08	1.90	0.98
90th %tile Delta-DV	0.101	2.207	2.106	2002	233	90	72	2.2	31.69	58.45	8.17	1.69
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.653	4.929	2.275	2000	47	99	81	2.9	34.78	63.77	1.04	0.41
98th %tile Delta-DV	0.606	2.773	2.167	2000	233	99	81	2.4	52.67	45.27	1.46	0.60
90th %tile Delta-DV	0.215	2.447	2.232	2000	209	99	81	2.7	34.43	54.11	8.62	2.85
2001												
Largest Delta-DV	3.302	5.641	2.340	2001	326	97	79	3.2	38.39	59.61	1.57	0.43
98th %tile Delta-DV	0.909	3.249	2.340	2001	333	99	81	3.2	25.62	70.86	2.41	1.12
90th %tile Delta-DV	0.224	2.370	2.145	2001	107	97	79	2.3	16.30	79.89	2.88	0.93
2002												
Largest Delta-DV	1.645	3.985	2.340	2002	337	93	75	3.2	8.19	88.69	2.42	0.70
98th %tile Delta-DV	0.589	2.734	2.145	2002	111	99	81	2.3	33.04	62.70	3.45	0.81
90th %tile Delta-DV	0.135	2.280	2.145	2002	134	99	81	2.3	10.24	80.95	7.15	1.66

Duration Events

TRNP SOUTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 7  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2001  
Number of days with Delta-Deciview > 0.50: 7  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 18  
Number of days with Delta-Deciview > 1.00: 7  
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

2000  
Number of days with Delta-Deciview > 0.50: 5  
Number of days with Delta-Deciview > 1.00: 2  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 3  
Number of days with Delta-Deciview > 1.00: 0  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2002  
Number of days with Delta-Deciview > 0.50: 12  
Number of days with Delta-Deciview > 1.00: 6  
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
Number of days with Delta-Deciview > 0.50: 8  
Number of days with Delta-Deciview > 1.00: 4  
Max number of consecutive days with Delta-Deciview > 0.50: 1  
2001  
Number of days with Delta-Deciview > 0.50: 9  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2002  
Number of days with Delta-Deciview > 0.50: 17  
Number of days with Delta-Deciview > 1.00: 6  
Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
Number of days with Delta-Deciview > 0.50: 10  
Number of days with Delta-Deciview > 1.00: 1  
Max number of consecutive days with Delta-Deciview > 0.50: 2  
2001  
Number of days with Delta-Deciview > 0.50: 17  
Number of days with Delta-Deciview > 1.00: 5  
Max number of consecutive days with Delta-Deciview > 0.50: 3  
2002  
Number of days with Delta-Deciview > 0.50: 15  
Number of days with Delta-Deciview > 1.00: 3  
Max number of consecutive days with Delta-Deciview > 0.50: 2

Basin Electric Power Cooperative Leland Olds Station Unit 2 BART Run 2 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.781	4.015	2.234	2000	72	4	4	2.8	23.00	75.29	1.30	0.41
98th %tile Delta-DV	0.536	2.811	2.276	2000	335	53	107	3.0	27.23	65.78	5.61	1.38
90th %tile Delta-DV	0.135	2.284	2.149	2000	199	53	107	2.4	53.49	34.41	9.54	2.56
2001												
Largest Delta-DV	0.970	3.203	2.234	2001	64	46	46	2.8	36.29	62.47	0.91	0.33
98th %tile Delta-DV	0.526	2.632	2.106	2001	260	52	106	2.2	59.53	35.29	4.02	1.15
90th %tile Delta-DV	0.114	2.242	2.127	2001	302	1	1	2.3	6.70	90.51	2.28	0.51
2002												
Largest Delta-DV	2.753	4.986	2.234	2002	78	46	46	2.8	27.33	71.05	1.10	0.52
98th %tile Delta-DV	1.050	3.283	2.234	2002	74	49	103	2.8	31.60	66.61	1.35	0.44
90th %tile Delta-DV	0.225	2.353	2.127	2002	105	46	46	2.3	10.34	85.54	3.07	1.05
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.623	3.856	2.234	2000	36	82	71	2.8	21.10	78.05	0.62	0.23
98th %tile Delta-DV	0.556	2.832	2.276	2000	316	85	114	3.0	23.49	74.75	1.39	0.38
90th %tile Delta-DV	0.121	2.354	2.234	2000	46	68	57	2.8	6.92	89.17	3.21	0.70
2001												
Largest Delta-DV	1.307	3.540	2.234	2001	64	82	71	2.8	35.78	62.72	1.13	0.37
98th %tile Delta-DV	0.658	2.891	2.234	2001	63	82	71	2.8	45.58	53.25	0.79	0.39
90th %tile Delta-DV	0.146	2.421	2.276	2001	316	82	71	3.0	21.73	77.36	0.68	0.23
2002												
Largest Delta-DV	3.353	5.587	2.234	2002	73	89	118	2.8	23.54	74.16	1.84	0.47
98th %tile Delta-DV	1.091	3.324	2.234	2002	75	82	71	2.8	27.07	70.28	1.91	0.75
90th %tile Delta-DV	0.151	2.257	2.106	2002	241	82	71	2.2	77.68	20.05	1.67	0.60
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.786	4.019	2.234	2000	74	90	72	2.8	35.92	62.99	0.63	0.47
98th %tile Delta-DV	0.372	2.606	2.234	2000	69	90	72	2.8	18.00	78.49	2.81	0.71
90th %tile Delta-DV	0.114	2.284	2.170	2000	152	90	72	2.5	25.41	65.47	7.12	2.00
2001												
Largest Delta-DV	0.932	3.166	2.234	2001	64	90	72	2.8	37.42	61.33	0.93	0.33
98th %tile Delta-DV	0.346	2.601	2.255	2001	12	90	72	2.9	33.04	65.37	1.23	0.36
90th %tile Delta-DV	0.057	2.185	2.127	2001	101	90	72	2.3	45.96	53.12	0.57	0.35
2002												
Largest Delta-DV	2.986	5.220	2.234	2002	73	90	72	2.8	26.42	71.27	1.80	0.50
98th %tile Delta-DV	0.836	3.070	2.234	2002	39	90	72	2.8	28.38	68.99	1.74	0.90
90th %tile Delta-DV	0.109	2.215	2.106	2002	233	90	72	2.2	29.20	61.71	7.53	1.56
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.876	5.152	2.275	2000	47	99	81	2.9	31.71	66.97	0.95	0.37
98th %tile Delta-DV	0.647	2.814	2.167	2000	233	99	81	2.4	49.26	48.81	1.37	0.56
90th %tile Delta-DV	0.238	2.513	2.275	2000	70	93	75	2.9	19.43	78.10	1.81	0.65
2001												
Largest Delta-DV	3.540	5.880	2.340	2001	326	97	79	3.2	35.35	62.80	1.44	0.40
98th %tile Delta-DV	0.999	3.338	2.340	2001	333	99	81	3.2	23.22	73.59	2.18	1.01
90th %tile Delta-DV	0.232	2.400	2.167	2001	235	99	81	2.4	14.42	81.94	3.00	0.65
2002												
Largest Delta-DV	1.841	4.181	2.340	2002	337	93	75	3.2	7.25	90.00	2.14	0.62
98th %tile Delta-DV	0.643	2.789	2.145	2002	111	99	81	2.3	30.17	65.93	3.15	0.74
90th %tile Delta-DV	0.149	2.294	2.145	2002	122	99	81	2.3	21.01	77.00	1.26	0.74

Duration Events

TRNP SOUTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 8  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2001  
 Number of days with Delta-Deciview > 0.50: 8  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 21  
 Number of days with Delta-Deciview > 1.00: 8  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

2000  
 Number of days with Delta-Deciview > 0.50: 5  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 4  
 Number of days with Delta-Deciview > 1.00: 0  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2002  
 Number of days with Delta-Deciview > 0.50: 12  
 Number of days with Delta-Deciview > 1.00: 6  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 10  
 Number of days with Delta-Deciview > 1.00: 4  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 11  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 17  
 Number of days with Delta-Deciview > 1.00: 8  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
 Number of days with Delta-Deciview > 0.50: 13  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2001  
 Number of days with Delta-Deciview > 0.50: 21  
 Number of days with Delta-Deciview > 1.00: 7  
 Max number of consecutive days with Delta-Deciview > 0.50: 3  
 2002  
 Number of days with Delta-Deciview > 0.50: 15  
 Number of days with Delta-Deciview > 1.00: 3  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

Basin Electric Power Cooperative Leland Olds Station Unit 2 BART Run 3 2000-2002												
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	% of Modeled Extinction by Species				
								F(RH)	% SO4	% NO3	% PMC	% PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.503	4.736	2.234	2000	72	4	4	2.8	15.77	83.06	0.89	0.28
98th %tile Delta-DV	0.728	3.004	2.276	2000	335	53	107	3	19.84	75.06	4.09	1.00
90th %tile Delta-DV	0.178	2.284	2.106	2000	241	36	36	2.2	11.25	84.26	2.94	1.54
2001												
Largest Delta-DV	1.316	3.550	2.234	2001	64	46	46	2.8	26.27	72.83	0.66	0.24
98th %tile Delta-DV	0.660	2.936	2.276	2001	338	47	101	3	13.57	82.61	3.07	0.75
90th %tile Delta-DV	0.148	2.275	2.127	2001	101	45	45	2.3	32.11	67.07	0.53	0.28
2002												
Largest Delta-DV	3.723	5.957	2.234	2002	78	46	46	2.8	19.19	79.67	0.77	0.36
98th %tile Delta-DV	1.445	3.679	2.234	2002	74	49	103	2.8	22.50	76.23	0.96	0.31
90th %tile Delta-DV	0.336	2.463	2.127	2002	105	46	46	2.3	6.89	90.36	2.05	0.70
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.268	4.502	2.234	2000	36	82	71	2.8	14.60	84.81	0.43	0.16
98th %tile Delta-DV	0.800	3.076	2.276	2000	316	85	114	3	16.13	82.65	0.95	0.26
90th %tile Delta-DV	0.146	2.295	2.149	2000	187	87	116	2.4	71.86	24.74	2.38	1.02
2001												
Largest Delta-DV	1.790	3.917	2.127	2001	98	84	113	2.3	13.07	83.85	2.45	0.64
98th %tile Delta-DV	0.877	3.110	2.234	2001	63	82	71	2.8	33.86	65.27	0.58	0.29
90th %tile Delta-DV	0.181	2.415	2.234	2001	89	82	71	2.8	25.44	73.76	0.47	0.33
2002												
Largest Delta-DV	4.549	6.782	2.234	2002	73	89	118	2.8	16.28	82.12	1.27	0.32
98th %tile Delta-DV	1.496	3.730	2.234	2002	75	82	71	2.8	19.33	78.77	1.36	0.53
90th %tile Delta-DV	0.212	2.487	2.276	2002	352	71	60	3	10.30	88.72	0.76	0.22
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.380	4.613	2.234	2000	74	90	72	2.8	26.14	73.07	0.46	0.34
98th %tile Delta-DV	0.471	2.705	2.234	2000	32	90	72	2.8	14.28	84.16	1.08	0.47
90th %tile Delta-DV	0.142	2.269	2.127	2000	98	90	72	2.3	20.09	78.39	1.06	0.46
2001												
Largest Delta-DV	1.261	3.495	2.234	2001	64	90	72	2.8	27.20	71.89	0.67	0.24
98th %tile Delta-DV	0.477	2.732	2.255	2001	12	90	72	2.9	23.72	75.14	0.89	0.26
90th %tile Delta-DV	0.076	2.204	2.127	2001	101	90	72	2.3	34.65	64.67	0.43	0.26
2002												
Largest Delta-DV	4.036	6.269	2.234	2002	73	90	72	2.8	18.49	79.89	1.26	0.35
98th %tile Delta-DV	1.134	3.367	2.234	2002	39	90	72	2.8	20.63	77.46	1.26	0.65
90th %tile Delta-DV	0.142	2.376	2.234	2002	82	90	72	2.8	10.75	86.87	1.94	0.44
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.831	6.106	2.275	2000	47	99	81	2.9	22.64	76.42	0.68	0.27
98th %tile Delta-DV	0.830	2.998	2.167	2000	233	99	81	2.4	38.00	60.51	1.05	0.44
90th %tile Delta-DV	0.307	2.474	2.167	2000	226	99	81	2.4	34.63	59.20	4.91	1.26
2001												
Largest Delta-DV	4.528	6.868	2.340	2001	326	97	79	3.2	26.24	72.39	1.07	0.30
98th %tile Delta-DV	1.131	3.730	2.340	2001	333	99	81	3.2	16.35	81.41	1.54	0.71
90th %tile Delta-DV	0.339	2.506	2.167	2001	235	99	81	2.4	9.83	87.69	2.04	0.44
2002												
Largest Delta-DV	2.675	5.015	2.340	2002	337	93	75	3.2	4.78	93.41	1.41	0.41
98th %tile Delta-DV	0.886	3.031	2.145	2002	111	99	81	2.3	21.64	75.57	2.26	0.53
90th %tile Delta-DV	0.209	2.549	2.340	2002	362	99	81	3.2	20.31	79.25	0.36	0.07

Duration Events

TRNP SOUTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 11  
 Number of days with Delta-Deciview > 1.00: 4  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2001  
 Number of days with Delta-Deciview > 0.50: 15  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 27  
 Number of days with Delta-Deciview > 1.00: 15  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

2000  
 Number of days with Delta-Deciview > 0.50: 7  
 Number of days with Delta-Deciview > 1.00: 2  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 6  
 Number of days with Delta-Deciview > 1.00: 1  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 15  
 Number of days with Delta-Deciview > 1.00: 8  
 Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

2000  
 Number of days with Delta-Deciview > 0.50: 14  
 Number of days with Delta-Deciview > 1.00: 6  
 Max number of consecutive days with Delta-Deciview > 0.50: 1  
 2001  
 Number of days with Delta-Deciview > 0.50: 17  
 Number of days with Delta-Deciview > 1.00: 5  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2002  
 Number of days with Delta-Deciview > 0.50: 21  
 Number of days with Delta-Deciview > 1.00: 14  
 Max number of consecutive days with Delta-Deciview > 0.50: 3

LOSTWOOD NWA

2000  
 Number of days with Delta-Deciview > 0.50: 22  
 Number of days with Delta-Deciview > 1.00: 6  
 Max number of consecutive days with Delta-Deciview > 0.50: 2  
 2001  
 Number of days with Delta-Deciview > 0.50: 27  
 Number of days with Delta-Deciview > 1.00: 12  
 Max number of consecutive days with Delta-Deciview > 0.50: 3  
 2002  
 Number of days with Delta-Deciview > 0.50: 21  
 Number of days with Delta-Deciview > 1.00: 5  
 Max number of consecutive days with Delta-Deciview > 0.50: 3