Effect of DryFine™ Low Temperature Coal Drying Process on Emissions from a Coal-Fired Power Plant

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ABSTRACT

Great River Energy has developed and installed at Coal Creek Station a patented low temperature waste stream coal drying and segregation process (DryFine™) for North Dakota lignite. The process improves the heating value of the coal while reducing coal mercury, sulfur, and ash content. In addition to improvements in boiler efficiency and unit heat rate, the process results in lower SO_2, NO_X, Hg, and CO_2 emissions. Theoretical calculations predict other potential air pollution benefits such as an increase in mercury oxidation and subsequent removal by the wet FGD. This paper presents stack SO_2, NO_X, Hg, and CO_2 emissions for a coal-fired unit operating pre- and post-DryFine™ installation.

INTRODUCTION

U.S. low-rank coals have moisture contents ranging from 15 to 30 percent for sub-bituminous coals and from 25 to 40 percent for lignite. When high-moisture lignite coals are burned in utility boilers, about seven percent of the fuel heat input is used to evaporate fuel moisture. The use of high-moisture coals results in higher fuel flow rate, higher stack flue gas flow rate, higher station service power, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of low-moisture coals such as Eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the Western U.S. are attractive due to their low cost and SO_2 emissions. Although existing lignite

power plants are designed to burn wet lignite, a reduction in coal moisture content would increase efficiency, reduce pollution and reduce CO_2 emissions. Furthermore, the efficiency of ultra supercritical units burning high-moisture coals would be improved significantly by using dried coal as a fuel.

Most of the coal drying processes that have been developed to date depend on high-grade or process heat to reduce coal moisture content or employ complex equipment layouts using expensive materials to recover the latent heat of vaporization. This significantly increases the cost of thermal drying, which is the main barrier to large-scale industry acceptance of this technology.[1]

Great River Energy (GRE) led a team to develop a process that uses low-grade heat to evaporate a portion of fuel moisture from the lignite feedstock in a fluidized bed dryer (FBD). A moving fluidized bed coal dryer was selected for this project due to (1) its good heat and mass transfer characteristics which result in a much smaller dryer compared to a fixed bed design and (2) its high throughput which reduces number of required dryers. The process improves the heating value of the coal while reducing coal mercury, sulfur, and ash content. In addition to improvements in boiler efficiency and unit heat rate, the process results in lower SO_2, NO_X, CO_2, and Hg emissions. Theoretical calculations predict other potential air pollution benefits such as an increase in mercury oxidation and subsequent removal of oxidized mercury by the wet FGD.

GRE developed and installed this patented low temperature waste stream coal drying and segregation process (DryFine^{TM}) for North Dakota lignite at Coal Creek Station. Following system commissioning in December 2009, tests were performed in January and March 2010 to collect preliminary data on dryer operation, system performance, and effect of dried coal on unit performance and emissions. Controlled performance and emissions tests were completed in the spring of 2010. A final performance test is planned for the fall of 2010 after system optimization. The demonstration was conducted with the Department of Energy (DOE) under DOE Award Number DE-FC26-04NT41763.[2]

This paper reports on the impact and potential benefit of DryFine^{TM} at GRE's Coal Creek Station on SO_2, NO_X, CO_2, and mercury emissions. The test program was divided into two distinct measurement periods:

(1) Pre-DryFine^{TM} (i.e., baseline)
(2) Post-DryFine^{TM}

To determine the benefits of waste heat coal drying on power plant efficiency improvements and air pollution reductions, data collected by EPRI/URS from this project were combined with data collected by GRE. This report summarizes the following data from the pre- and post-DryFine^{TM} measurement periods:

- Plant Effects
- Flue Gas Emission Effects (SO_2, NO_X, CO_2, Hg)
- Byproduct Emission Effects (Coal, Ash, FGD)

EXPERIMENTAL

Description of Coal Creek Unit 1

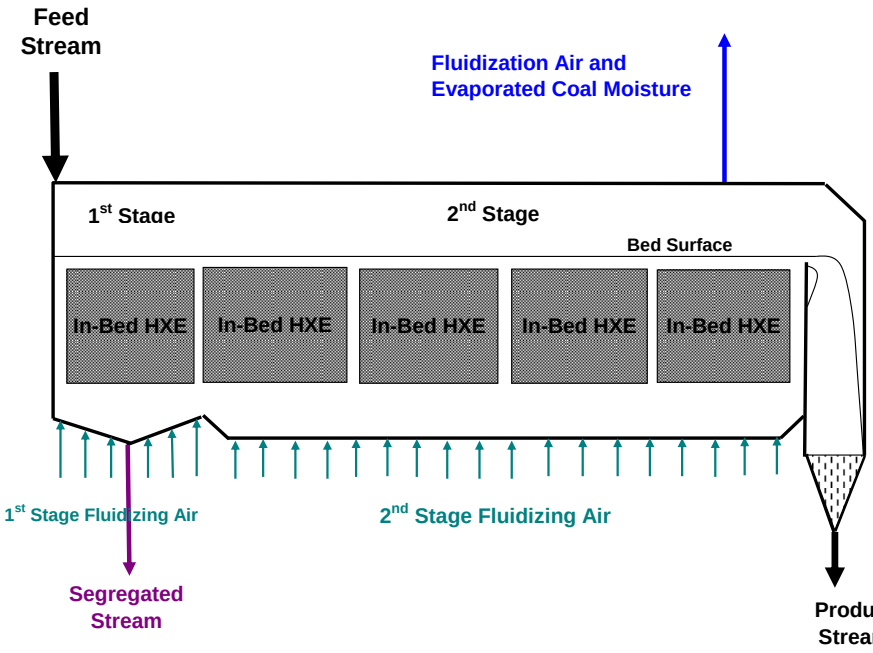
Coal Creek Station (CCS) is a 1,200 MW lignite-fired power plant located in Underwood, North Dakota. Two natural circulation dual furnace tangentially-fired CE boilers supply steam to two single reheat GE G-2 turbines rated at 600 MW each. The units are designed for 1,005°F main steam and reheat steam temperature at a throttle pressure of 2,520 psia. Three mechanical draft cooling towers are used to reject heat to the environment. The unit is equipped with a cold-side electrostatic precipitator (ESP) and a lime-based flue gas desulfurization (FGD) system.

DryFine™ Process Background

A theoretical analysis, performed by Lehigh University's Energy Research Center (ERC) in 1997-98 confirmed that a decrease in fuel moisture would have a significant positive effect on unit performance.[3] Based on these theoretical results, CCS personnel performed test burns with partially dried lignite in 2001 to assess whether the boiler and coal handling system could handle the partially dried lignite and to confirm theoretical performance improvement predictions.[3] Based on these results, an approach was selected that employed waste heat sources available in the plant for thermal drying of the incoming raw lignite stream using a fluidized bed dryer (FBD).[4]

The full-size commercial FBD was designed and constructed with three stages. Figure 1 provides a diagram of an FBD system. Multi-stage design allows maximum utilization of fluidized bed mixing, segregation and drying characteristics. All stages of the FBD are fluidized by air. Coal fines, elutriated from the FBD and collected by the dust collector (baghouse), are returned to the dryer. Each FBD is equipped with its own baghouse. De-dusted fluidizing air streams leaving the baghouses of two adjacent FBDs are combined and discharged through a common dryer stack into the atmosphere. The process operates below 300°F.

Figure 1: FBD Schematic



The design throughput of the full-scale system is 3.75 million tons per year of coal, sufficient to meet 100 percent of Unit 2's needs. Four full-scale dryers provide the necessary throughput with conservative redundancy. At the nominal coal feed rate, the four dryers supply 450 t/hr of dried coal to one unit, assuming an elutriation rate of 10 percent. At the nominal coal feed rate, target product moisture content is 29.5% for an inlet coal moisture of 38%. At the maximum coal feed rate, product moisture content is 30.6%.

Test Matrix

Two series of controlled tests were performed at Coal Creek Unit 1 with wet and dried lignite to determine the effect of the DryFine™ process on unit performance, emissions and operation. Wet lignite was fired during the pre-DryFine™ (i.e., baseline) test series, which was conducted September 15-18, 2009. The post-DryFine™ test series was performed on March 31 and April 1, 2010, after the commercial coal drying system was commissioned. The unit fired dried and cleaned lignite with the segregation stream cleaned by air jigs before being mixed with the product stream.

The unit was kept at steady state operating conditions during the pre- and post-DryFine™ test runs. Individual test runs were typically 2-3 hours long. Results from individual runs were averaged together and reported. For the tests, the turbine throttle pressure was set at 2,520 psig with control valves 100% open; the main steam temperature was set at 1,000°F, and reheat steam temperature was set at 1,005°F. Boiler excess O_2 was maintained at 2.6%. During the pre-DryFine™ test, the turbine cycle was isolated by switching building heat and auxiliary loads to Unit 2 while testing was performed on Unit 1. During the post-DryFine™ performance test, Unit 2 was in outage, so the Unit 1 steam turbine cycle could not be isolated; auxiliary extractions were taken from Unit 1. These extractions do not affect the emissions profile of the plant, but they must be accounted for in the calculation of unit performance.

Sootblowing was out of service during the multi-hour tests. Boiler sootblowing was performed before and between the performance tests. Samples of bottom ash, economizer ash, mill rejects, and fly ash were taken once per day. Economizer ash flow rate was determined from load cells. Fly ash was assumed to be 60 percent of the total ash flow, based on historic data. For the baseline tests, pressure differential in the scrubber was maintained at 6.5"wg for Unit 1.

Monitored and calculated unit performance parameters included gross power output, gross turbine cycle heat rate, boiler efficiency, auxiliary power use, net unit heat rate, coal feed, fuel heat input to the boiler and other parameters.

Additional flue gas measurements were made during these periods. Figure 2 provides a diagram of Coal Creek Unit 1 and all gas and solid or liquid sample locations. NO_x, SO_2, Hg and CO_2 were measured at the stack. Although Method 29 trace metals measurements were performed at the stack during the pre-DryFine™ test period, the results are not reported in this paper. Method 29 measurements were not performed during the post-DryFine™ test period due to complications arising from an unplanned outage on Unit 1.

Two mercury (Hg) semi-continuous mercury monitors (CMMs) were operated by URS during the tests: one located at the air heater inlet (AH inlet) and a second that rotated measurements between the FGD bypass, FGD outlet, and FGD inlet locations. A third CMM was operated by GRE at the stack during the post-DryFine™ test period, but it was unavailable during the pre-DryFine™ test period. The CMMs were used to measure total and elemental flue gas mercury concentrations.

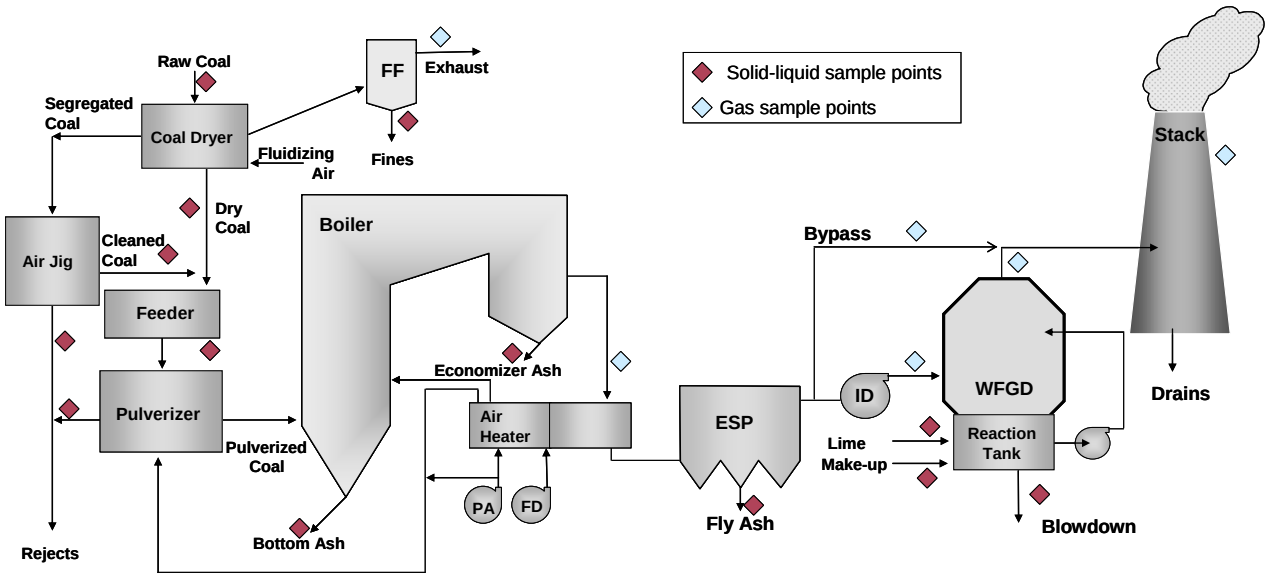
Additional solid and liquid samples were collected and analyzed during the test periods. Raw coal samples collected during pre-DryFine™ were analyzed for ultimate/proximate parameters, major ash minerals, mercury, chlorine, and trace metals. Post-DryFine™ coal underwent the same measurements but, in addition, samples were also collected from the feeder inlet, the segregated coal stream, the clean coal stream, and the pulverizer rejects stream. FGD samples for both the pre- and post- DryFine™ were collected from the absorber blowdown, Missouri river water, service water, and lime slaker. All streams were analyzed for mercury, and the absorber blowdown was also analyzed for SO_3, Cl, and weight percent.

RESULTS

This section is organized in the following manner:

- Unit 1 Plant Effects
    - Unit Load
    - Coal Flow
    - Flue Gas Flow
- Flue Gas Emission Effects
    - SO_2 & NO_X Flue Gas Emissions
    - CO_2 Flue Gas Emissions
    - Hg Flue Gas Emissions
- ByProduct Emission Effects
    - Coal and Ash Analysis
    - FGD Analysis

Figure 2: Diagram of Coal Creek Unit 1 and Sampling Locations



Unit 1 Plant Effects

Table 1 provides an overall picture of pre- and post-DryFine™ SO_2, NO_X, and CO_2 emissions at the stack.

Heat Input

The unit operated at nominally the same load of 600 MW for the pre-DryFine™ and post-DryFine™ test periods. The heat input required to achieve this load during post-DryFine™ was 3.0% lower than pre-DryFine™.

Coal Flow

As a portion of coal moisture is evaporated by thermal drying, the coal higher heating value (HHV) increases and the required coal feed flow rate to the boiler decreases. This decrease is mostly due to removal of coal moisture and partially due to improvement in unit efficiency. The coal feed rate for the post-DryFine™ period was 10.3% less than the coal feed rate during the pre-DryFine™ period.

Flue Gas Flow

When firing post-DryFine™ coal, the flue gas flow rate as measured on a mass basis by the plant CEM was lowered on average 2.9% as compared to pre-DryFine™ wet coal.

Table 1: Pre-DryFine™ and Post-DryFine™ Emissions

Parameter (Measured or Calculated at Stack)	Units	Pre-DryFine™ (Wet Coal) Baseline	Preliminary Post-DryFine™ (Dry Coal) Results	% Change Relative to Pre-DryFine™
Calculated CEM Heat Input	MBtu/hr	5,694	5,525	-3.0
Flue Gas Flow Rate	kacfm	2,016	1,860	-7.7
Flue Gas Flow Rate	klb/hr	6781	6582	-2.9
Measured NO_X Concentration	ppmv (actual)	148	105	-29.0
NO_X Emissions Rate	lb/MBtu	0.284	0.194	-31.8
NO_X Emissions Rate	lb/hr	1617	1071	-33.8
SO_2 Removal	%	73.3	85.6	
Measured SO_2 Concentration	ppmv (actual)	216	103	-52.3
SO_2 Emissions Rate	lb/MBtu	0.577	0.265	-54.1
SO_2 Emissions Rate	lb/hr	3,285	1,464	-55.4
Measured CO_2 Concentration	% vol	11.88	12.35	4.0
CO_2 Emissions Rate	klb/MBtu	0.216	0.223	3.2
CO_2 Emissions Rate	klb/hr	1,230	1,232	0.2

Flue Gas Emission Effects

SO_2 Flue Gas Emissions

SO_2 removal was calculated from SO_2 concentrations measured at the scrubber inlet and the stack. The SO_2 removal across the unit increased from 73.3% during pre-DryFine™ to 85.6% during post-DryFine™. This increase in SO_2 removal was attributable to a higher percentage of total flue gas flow being scrubbed, which was possible due to 3.4% lower total mass flow rate of flue gas and 50°F lower flue gas temperature at the scrubber inlet, which resulted in 7.7% lower volumetric flow of flue gas. For pre-DryFine™ tests with wet coal, the pressure differential in each Unit 1 scrubber was set to 6.5”wg. During post-DryFine™ tests it was possible to increase scrubber pressure differential to 8.5”wg.

With Dry-Fine, the SO_2 concentration in the stack flue gas was reduced by 52% compared to the pre-DryFine™ wet coal baseline, and SO_2 mass emission rate was reduced by 55%. The reduction in SO_2 emissions was attributable to more efficient SO_2 scrubbing, removal of sulfur from the coal by the dense particle segregation process, and lower coal flow.

NO_X Flue Gas Emissions

The nitrogen content of the coal was twice as high for the post-DryFine™ vs. pre-DryFine™ coal. Despite this increase in nitrogen content, during post-DryFine™ operation the stack NO_X concentration was reduced by 29% as compared to pre-DryFine™. The NO_X emissions rate was reduced by ~33% as compared to pre-DryFine™. The reduction in NO_X formation was mostly attributable to lower primary air flow. Furthermore, reduced primary air flow allowed for increased secondary air flow and thus better combustion staging and lower NO_X emissions. With post-DryFine™ dried coal, Unit 1 achieved full load with six mills in service, compared to the eight mills which are typically needed for wet coal. This further increased combustion staging.

CO_2 Flue Gas Emissions

The average CO_2 mass emissions rate for post-DryFine™ coal (1232 klb/hr) was 0.20%-point higher compared to the average value corresponding to the pre-DryFine™ baseline (1230 klb/hr). Such a small change in CO_2 mass emissions rate is difficult to quantify accurately due to measurement precision and instrument drift issues.

No decrease in CO_2 concentration was observed with DryFine™ for the following reasons: (1) the carbon content of the coal fired during post-DryFine™ was 0.8%-points higher than the baseline wet coal, and (2) the Unit 2 outage during the Unit 1 post-DryFine™ test resulted in Unit 1 providing auxiliary loads thus resulting in higher heat rate and lower gross load. If Unit 1 had been operating with no auxiliary loads during the post-DryFine™ test (as it had for the baseline pre-DryFine™ test), a 3 – 4% reduction in CO_2 emission rate would have been expected. Additional DryFine™ testing will be performed in fall of 2010 with both units at Coal Creek being in service so steam extraction for auxiliaries can be moved to Unit 2.

Hg Flue Gas Emissions

Prior to the start up of the DryFine™ system, total mercury concentration measured by the plant Hg CEM from mid-October 2009 to late December varied between typical values of 11 to 15 $\mu g/dNm^3$ at 3% O_2. After the DryFine™ coal drying system was put in service, total mercury concentrations at the stack decreased by approximately 12% (Figure 3).

Figure 3: Stack Total Hg Concentrations as Measured by Plant Hg CEM

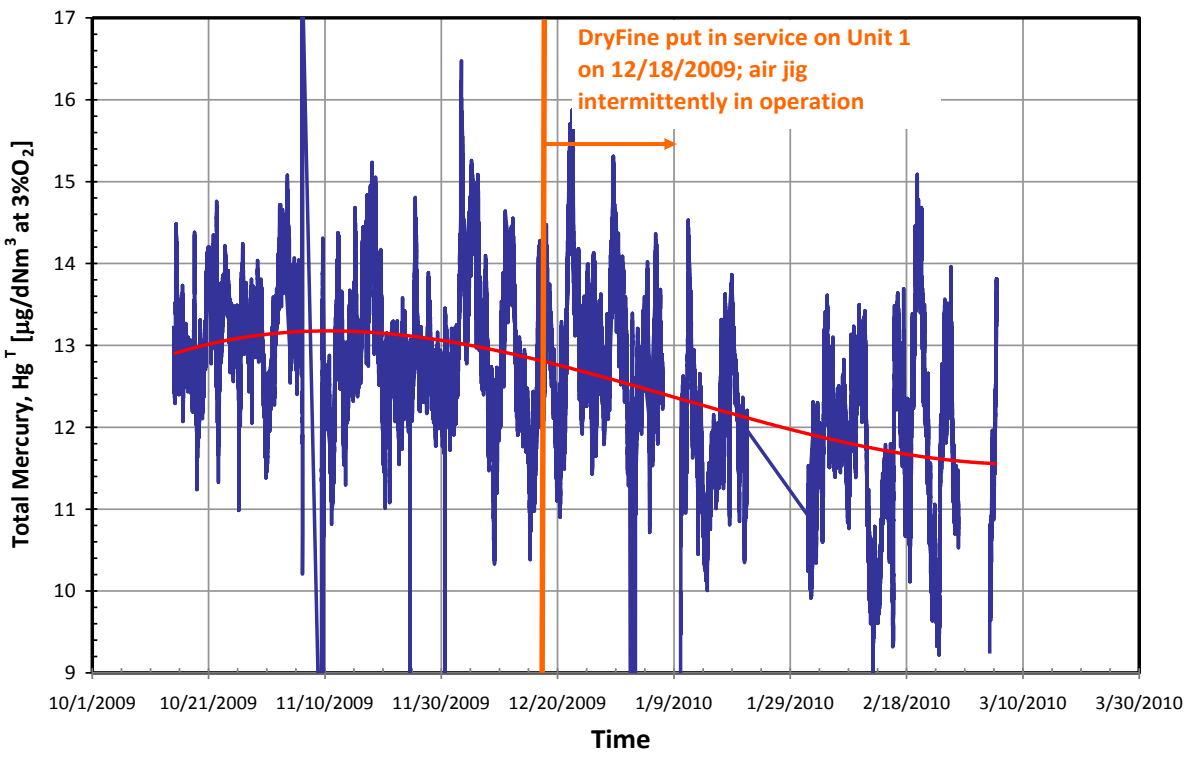


Table 2 compares the pre- and post-DryFine™ mercury emissions at each flue gas measurement location. It also provides percent mercury removal and re-emissions information. System mercury removals were not calculated as coal Hg data were not available at the time this paper was written. System mercury removals must be calculated with respect to the raw coal, since the dense particle segregation in the DryFine™ process reduces the mercury content of the coal fired. With the DryFine™ process, total mercury concentration at the air heater inlet decreased from an average of 18.7 µg/ dNm^3 to 15.5 µg/ dNm^3. Mercury oxidation at the FGD inlet increased from 28% to 41% with the DryFine™ process; likewise, mercury oxidation at the bypass increased from 22% to 36%. The FGD outlet Hg concentration decreased from 13.0 to 9.6 µg/ dNm^3 with the DryFine™ process.

Flue gas mercury concentration data across the FGD were used as the basis for calculating the percent of oxidized mercury at the FGD inlet re-emitted as elemental mercury at the FGD outlet. Mercury re-emissions from FGD systems occur when soluble oxidized mercury is captured in a wet FGD system and then reduced to the insoluble elemental form of mercury. The chemistry governing re-emissions is not fully understood; laboratory studies have shown that factors such as pH, oxidation-reduction potential (ORP), SO_3^{2-}, and Cl^- concentrations affect the tendency for re-emissions. During pre-DryFine™ tests, the percent of oxidized mercury removed across the FGD averaged 85%, and the percent of oxidized mercury re-emitted as elemental mercury averaged 12%. During post-DryFine™ tests, the percent oxidized mercury removed across the FGD averaged 89%, and the percent oxidized mercury re-emitted as elemental mercury averaged 16%. Within the level of accuracy of the mercury measurements, the mercury removal profile of the FGD did not change from baseline to post-DryFine™ .

Table 2. Comparison of Pre- to Post-DryFine™ Hg Emissions Profile (all concentrations expressed as µg/dNm^3 at 3% O_2).

Location	Parameter	Pre-DryFine™ Average	Post-DryFine™ Average
AH Inlet	Total Hg	18.7	15.5
	Elemental Hg	18.1	15.4
	% Oxidized Hg	8%	2%
FGD Inlet	Total Hg	16.0	14.1
	Elemental Hg	11.6	7.9
	% Oxidized Hg	28%	41%
FGD Outlet	Total Hg	13.0	9.6
	Elemental Hg	12.2	8.9
	% Oxidized Hg	5%	6%
Bypass	Total Hg	14.8	14.4
	Elemental Hg	11.6	9.7
	% Oxidized Hg	22%	36%
Stack	Total Hg	N/A	8.7
	Elemental Hg	N/A	8.3
	% Oxidized Hg	N/A	5%
Other Calculations	% Hg^{ox} Removal Across FGD	85%	89%
	% Hg^{ox} Re-emitted as Hg^0	22%	16%
	Expected Stack Hg Conc., assuming 20% bypass for BL, 12% bypass for DryFine™	13.6	10.0

Byproduct Emission Effects

Coal & Ash Analysis

Solid samples were taken from the raw (wet) coal stream entering the unit, mill (pulverizer) rejects (manual sample), economizer ash (manual sample), bottom ash (manual sample), and fly ash (manual sample). With the coal drying system in operation, coal samples were also taken from the segregated coal stream (air jig inlet), cleaned coal (air jig outlet), and dried coal (coal dryer) feeders (product stream), and scrubber limestone feed. Coal mercury analyses were not available at the time this paper was written.

Mercury content in the ash was < 0.01 µg/g (0.01 ppm). Pulverizer rejects were high in sulfur (average 13%) and mercury (average 5 µg/g), where mercury was most likely included in pyrite. Although concentration of mercury in pulverizer rejects was more than two orders of magnitude higher than in the coal, pulverizer rejects represented only 0.02 – 0.03% of raw coal flow.

Chlorine in raw coal and product streams was low at 24 and 19 ppm, respectively.

FGD Analysis

FGD absorber mercury concentrations are reported in for pre-and post-DryFine™ test periods in Table 3. Missouri river water, service water, and lime slaker were all tested for mercury. During pre- and post-DryFine™, these streams all measured below the detection limit of 0.31µg/L. Several additional parameters were measured in the FGD unit during pre- and post-DryFine™ and are reported in Table 4. These parameters are presented to characterize the chemistry of the scrubber during the tests. The effect of the DryFine™ process on FGD chemistry should not be assessed from this limited set of data.

Table 3. Average FGD Absorber Mercury Concentrations for Test Periods

Sample Location	Period	Hg in Liquor (µg/L)	Hg in Solids (µg/g)	Wt% Solids	% Hg in Liquor	% Hg in Solids
Absorber Blowdown	Pre-DryFine™	3.2	0.50	12.94	4.1%	95.9%
Absorber Blowdown	Post-DryFine™	0.8	0.93	9.70	0.8%	99.2%

Table 4. FGD Absorber Chemistry during Test Periods

Period	Pre-DryFine™ Average	Post-DryFine™ Average
wt%	12.94	9.70
pH	6.37	5.80
Temp [°C]	60.3	56.0
ORP	29.0	33.5
Liquid Phase Cl [mM]	24.82	15.78
Liquid Phase Br [mM]	0.19	-
Liquid Phase SO_3 [mM]	19.86	12.19
Solid Phase Fe [ppm]	<0.3	<0.3

CONCLUSION

GRE installed a patented low-temperature coal drying and density segregation process (DryFine™) at Coal Creek Station Units 1 and 2. This process reduces coal moisture, sulfur, mercury, and ash content and thereby should increase unit efficiency, reduce pollution and reduce CO_2 emissions. Performance tests were conducted pre and post-DryFine™ installation to quantify the effect on unit operation and gas phase emissions. Operation of the DryFine™ process resulted in lower coal feed rates and lower flue gas volumes. The lower flue gas volume allowed the scrubbers to be operated at higher pressure drop and for more flue gas to be scrubbed. SO_2 removal efficiency increased from 73.3% to 85.6%, and SO_2 emissions decreased by 54%. Despite an increase in coal nitrogen content during post-DryFine™ operation, the stack NO_X concentration was reduced by 29% as compared to pre-DryFine™. The NO_X emissions rate was reduced by ~32% as compared to pre-DryFine™. The reduction in NO_X was primarily attributable to a decrease in primary air flow. No decrease in CO_2 concentration was observed with DryFine™, likely because of an increase in coal carbon content during the post-DryFine™ test and because the Unit 1 turbine could not be isolated from auxiliary loads (due to Unit 2 outage). A decrease in stack Hg emissions was observed upon commencement of DryFine™ operation; this decrease is attributable to the segregation of dense particles from the coal and an increase in mercury oxidation in the flue gas upstream of the FGD.

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