LIGNITE FUEL ENHANCEMENT

Final Technical Report

Reporting Period: July 9, 2004 to March 31, 2010
DOE Award Number: DE-FC26-04NT41763
Date Report Issued: June 29, 2010
Report Submitted by: Great River Energy

Authors:

Charles W. Bullinger, PE
Senior Principle Engineer
Great River Energy
1611 E. Century Avenue
Bismarck, ND 58503

Dr. Nenad Sarunac
Principle Research Engineer
Energy Research Center
117 ATLSS Drive, Imbt Labs
Lehigh University
Bethlehem, PA 18015

DISCLAIMER

ACKNOWLEDGEMENT

This report was prepared with the support of the U.S. Department of Energy (DOE), under Award No. DE-FC26-04NT41763 (Clean Coal Power Initiative/National Energy Technology Laboratory/Office of Fossil Energy). The authors wish to acknowledge the contributions and support provided by various project managers: Dr. Sai Gollakota (DOE), Mark Ness (GRE), Matt Coughlin (North Engineering), Dave Rian (Barr Engineering), Drs. Edward K. Levy and Carlos E. Romero (Lehigh University), and John Wheeldon and Tony Armor (EPRI).

ABSTRACT

Pulverized coal power plants which fire lignites and other low-rank high-moisture coals generally operate with reduced efficiencies and increased stack emissions due to the impacts of high fuel moisture on stack heat loss and pulverizer and fan power.

A process that uses plant waste heat sources to evaporate a portion of the fuel moisture from the lignite feedstock in a moving bed fluidized bed dryer (FBD) was developed in the U.S. by a team led by Great River Energy (GRE). The demonstration was conducted with Department of Energy (DOE) funding under DOE Award Number DE-FC26-04NT41763. The objectives of GRE's Lignite Fuel Enhancement project were to demonstrate reduction in lignite moisture content by using heat rejected from the power plant, apply technology at full scale at Coal Creek Station (CCS), and commercialize it.

The Coal Creek Project has involved several stages, beginning with lignite drying tests in a laboratory-scale FBD at the Energy Research Center (ERC) and development of theoretical models for predicting dryer performance. Using results from these early stage research efforts, GRE built a 2 ton/hour pilot-scale dryer, and a 75 ton/hour prototype drying system at Coal Creek Station. Operated over a range of drying conditions, the results from the pilot-scale and prototype-scale dryers confirmed the performance of the basic dryer design concept and provided the knowledge base needed to scale the process up to commercial size. Phase 2 of the GRE's Lignite Fuel Enhancement project included design, construction and integration of a full-scale commercial coal drying system (four FBDs per unit) with Coal Creek Units 1 and 2 heat sources and coal handling system.

Two series of controlled tests were conducted at Coal Creek Unit 1 with wet and dried lignite to determine effect of dried lignite on unit performance and

emissions. Wet lignite was fired during the first, wet baseline, test series conducted in September 2009. The second test series was performed in March/April 2010 after commercial coal drying system was commissioned.

Preliminary tests with dried coal were performed in March/April 2010. During the test Unit 2 was in outage and, therefore, test unit (Unit 1) was carrying entire station load and, also, supplying all auxiliary steam extractions. This resulted in higher station service, lower gross power output, and higher turbine cycle heat rate. Although, some of these effects could be corrected out, this would introduce uncertainty in calculated unit performance and effect of dried lignite on unit performance.

Baseline tests with dried coal are planned for second half of 2010 when both units at Coal Creek will be in service to establish baseline performance with dried coal and determine effect of coal drying on unit performance.

Application of GRE's coal drying technology will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although existing lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution and CO_2 emissions, and improve plant economics. Furthermore, the efficiency of ultra supercritical units burning high-moisture coals will be improved significantly by using dried coal as a fuel.

To date, Great River Energy has had 63 confidentiality agreements signed by vendors and suppliers of equipment and 15 utilities. GRE has had agreements signed from companies in Canada, Australia, China, India, Indonesia, and Europe.

TABLE OF CONTENTS

TABLE OF CONTENTS ***(continued)***

LIST OF FIGURES

LIST OF FIGURES *(continued)*

LIST OF FIGURES *(continued)*

LIST OF FIGURES *(continued)*

LIST OF TABLES

LIST OF ABBREVIATIONS

APH	Air Preheater
B	Heat Credits to the Boiler
Br	Bromine
BTCE	Boiler/Turbine Cycle Efficiency Method
Btu	British thermal unit
CCS	Coal Creek Station, Carbon Capture and Sequestration
CCPI	Clean Coal Power Initiative
CD	Coal Dryer
CD11	Coal Dryer 11 (fist dryer on Unit 1)
CD26	Coal Dryer 26 (Prototype Coal Dryer)
Cl	Chlorine
CEM	Continuous Emissions Monitor
CFHR	Heat Rate Correction Factor for ASME Group 1 and 2 Corrections
CO	Carbon Monoxide, ppm
CO_2	Carbon Dioxide, percent
$CO_{2,Stack}$	Carbon Dioxide Concentration Measured by the Plant CEM, ppm
CS2	Automatic As-received Coal Sampler
C_{NOx}	NO_x Concentration in Flue Gas, ppm
DOE	Department of Energy
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERC	Energy Research Center
ESP	Electrostatic Precipitator
E_{NOx}	NO_x Emissions Rate, lb/MBtu
FBD	Fluidized Bed Dryer
FD	Forced Draft
FEGT	Furnace Exit Gas Temperature
FGD	Flue Gas Desulphurization Reactor (wet scrubber in this report)
F_c	CO_2 F-factor, scf/MBtu
GRE	Great River Energy

Hg	Mercury, $\mu g/Nm^3$
Hg^T	Total Mercury, $\mu g/Nm^3$
Hg^0	Elemental Mercury, $\mu g/Nm^3$
Hg^{2+}	Oxidized Mercury, $\mu g/Nm^3$
H_2O	Water (moisture), percent
HHV	Coal Heating Value, Btu/lb
HR	Heat Rate, Btu/kWh
HR_{CYCLE}	Gross Turbine Cycle Heat Rate, Btu/kWh
HR_{CYCLE}^{CORR}	Corrected Gross Turbine Cycle Heat Rate, Btu/kWh
$HR_{CYCLE,GROSS}$	Gross Turbine Cycle Heat Rate, Btu/kWh
HR_{NET}	Net Unit Heat Rate, Btu/kWh
$HR_{NET,IO}$	Net Unit Heat Rate Calculated by the Input/Output Method
$HR_{NET,BTCE}$	Net Unit Heat Rate Calculated by the BTCE Method, Btu/kWh
ID	Induced Draft
IGS	Inertial Gas Separation Filter
J	Joule
K	Degrees Kelvin
kW	kilowatt
lb	Pound (of mass in this report)
L	Energy Losses from Boiler
m	Meter
M	Flow Rate, klb/hr
M_{PA}	Flow Rate of Primary Air, klb/hr
M_{COAL}	Coal Flow Rate, klb/hr
M_{CO2}	Mass Flow Rate of CO_2 at Stack, klb/hr
M_{STACK}	Mass Flow Rate of Flue Gas at Stack, klb/hr
MW	Megawatt
N	Newton
NETL	National Energy Technology Laboratory
NO_x	Nitrous Oxide, ppm or lb/MBtu
OFA	Overfire Air

OPM	Online Performance Monitoring Workstation
ORP	Oxidation-reduction Potential
ppm	Part Per Million
psi	Pounds per Square Inch
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gauge
PA	Primary Air
P_{AUX}	Auxiliary (Station Service) Power, kW
P_G	Gross Power Output, MW
P_{STACK}	Pressure in the Stack at CEM Elevation, inch H_2O
P_{STD}	Standard Pressure, inch H_2O, psi, or N/m^2
Q_{CEM}	CEM Heat Input, MBtu/hr
Q_{FUEL}	Heat Input with Fuel to Boiler, MBtu/hr
Q_{STEAM}	Heat Transferred in Boiler to Steam, MBtu/hr
Q_1	Heat Input to Dryer, MBtu/hr
Q_2	Heat Demand of Dryer, MBtu/hr
R	Gas Constant
RATA	Relative Accuracy Test Audit
R_{univ}	Universal Gas Constant
sCEM	Semi-Continuous Emissions Monitor
S	Sulfur, percent
SA	Secondary air
SOFA	Separated Overfire Air
SP	Set-point
SO_2	Sulfur Dioxide, ppm, lb/MBtu or lb/hr
SO_3	Sulfur trioxide, ppm
T	Temperature, ^oF, ^oC, or K
TM	Total Moisture, percent on weight basis
T_{mill}	Temperature of Primary Air- Coal Mixture at Mill Outlet, ^oF
T_{HRHT}	Hot Reheat Steam Temperature, ^oF
T_{MST}	Main Steam Temperature, ^oF

T_{RHT}	Reheat Steam Temperature, ^{o}F
T_{STACK}	Temperature of Flue Gas in the Stack, ^{o}F
T_{STD}	Standard Temperature, ^{o}F, ^{o}C, or K
VWO	Valve Wide Open
V_{Stack}	Volumetric Flow of Flue Gas Measured by Plant CEM, acfm
$V_{Stack, STP}$	Volumetric Flow of Flue Gas at Std. Pressure and Temperature
wg	Water Gauge
x	Dimensionless Heat Input
^{o}C	Degrees Celsius
^{o}F	Degrees Fahrenheit
η	Efficiency, percent
η_{B}	Boiler Efficiency, percent
$\eta_{B,BTCE}$	Boiler Calculated by the BTCE Method, percent
$\eta_{B,ASME,PTC4.1}$	Boiler Efficiency Calculated by the ASME PTC 4.1, percent
η_{NET}	Net Unit Efficiency, percent
ρ_{STACK}	Density of Flue Gas at T_{STACK} and P_{STACK}, lb/ft^{3}

EXECUTIVE SUMMARY

Pulverized coal power plants which fire lignites and other low-rank high-moisture coals generally operate with reduced efficiencies and increased stack emissions due to the impacts of high fuel moisture on stack heat loss and pulverizer and fan power.

A process that uses plant waste heat sources to evaporate a portion of fuel moisture from the lignite feedstock in a moving bed fluidized bed dryer was developed in the U.S. by a team led by Great River Energy (GRE). The research was conducted with Department of Energy (DOE) funding under DOE Award Number: DE-FC26-04NT41763. The objectives of GRE's Lignite Fuel Enhancement project are to demonstrate reduction in lignite moisture content by using heat rejected from the power plant, apply technology at full scale at Coal Creek Station (CCS), and to commercialize the coal drying technology.

Although existing lignite power plants are designed to burn wet lignite, application of GRE's coal drying technology will significantly enhance the value of lignite as a fuel in electrical power generation power plants; reduction in moisture content will increase efficiency, reduce emissions of NO_x, SO_2, Hg, and CO_2, and improve plant economics. Furthermore, efficiency of ultra supercritical units burning high-moisture coals will be improved significantly by using dried coal as a fuel.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station using phased approach. In Phase 1 of the Lignite Fuel Enhancement project, a full-scale 75 ton/hour prototype coal drying system was designed, constructed, and integrated with Coal Creek Unit 2 heat sources and coal handling system. The prototype FBD operated over a range of operating conditions almost continuously from February 2006 to summer of 2009

and confirmed the capability of the full-scale dryer to reduce fuel moisture to the target level.

The objectives of Phase 2 of the GRE's Lignite Fuel Enhancement project included design, construction and integration of a full-scale commercial coal drying system with Coal Creek Units 1 and 2 heat sources, coal handling and control systems, and determination of effect of dried lignite on unit performance, emissions, and operation. The commercial coal drying system at Coal Creek includes four commercial-size moving bed fluidized bed dryers per unit, coal crushers, a coal conveying system, particulate control system, and instrumentation and controls.

System commissioning was completed in December 2009. Functional tests of coal dryer 11 were conducted in January 2010 to obtain preliminary information on the dryer and baghouse operation and performance.

Two series of controlled tests were conducted at Coal Creek Unit 1 at full load steady-state conditions with wet and dried lignite to determine effect of reduced coal moisture content on unit performance, emissions and operation. Wet lignite was fired during the first test series (wet coal baseline) conducted in September 2009. The second test series was performed in March/April 2010 after commercial coal drying system was commissioned.

September 2009 test data was used to establish baseline performance and emissions levels. Turbine cycle was isolated by switching auxiliary steam extractions to Unit 2. Boiler efficiency and net unit heat rate were determined by several methods.

Preliminary tests with dried coal were performed in March/April 2010. During the test, Unit 2 was in outage and test unit (Unit 1) was carrying all station auxiliary loads in addition to providing all auxiliary steam extractions. This resulted in higher station service and turbine cycle heat rate. Although, some of these effects could be corrected out, this would introduce uncertainty in calculated unit performance and effect of dried lignite on performance.

Baseline tests with dried coal are planned for second half of 2010 when both units at Coal Creek will be in service to establish baseline performance with dried coal and determine effect of coal drying on boiler efficiency and unit performance.

NO_x, SO_2, and CO_2 Emissions

Emissions parameters for tests performed with wet and dried lignite are summarized in Table E-1. For preliminary tests performed with dried coal NO_x concentration and emissions rate decreased by 29 and 31.8 percent, respectively relative to the wet coal. SO_2 concentration, emissions rate and mass emissions decreased by approximately 52 and 54 percent, respectively relative to the wet coal.

CO_2 concentration measured by the plant monitor for preliminary tests with dried coal increased 4 percent relative to the wet coal baseline. This increase is attributed to 2%-point lower moisture content in the flue gas and 0.8%-point higher carbon content in as-received lignite during preliminary tests with dried coal, compared to the wet coal baseline tests, and to instrument drift.

CO_2 mass emissions rates for preliminary tests with dried coal determined from calculated values of CO_2 concentration were approximately 3.8 percent lower compared to the wet coal. Specific CO_2 emissions expressed as weight percentage of CO_2 in the flue gas divided by carbon content in coal for dried coal were approximately 2.9 percent lower relative to the wet coal.

Table E-1: Effect of Dried Lignite on Emissions Parameters

Parameter (Measured or Calculated at Stack)	Units	Wet Coal Baseline	Prelimary Dried Coal Tests	% Change Realtive to Wet Coal
Measured NO_x Concentration	ppmv	148	105	-29.0
NO_x Emissions Rate	lb/MBtu	0.284	0.194	-31.8
Measured SO_2 Concentration	ppmv	216	103	-52.3
SO_2 Emissions Rate	lb/MBtu	0.577	0.265	-54.1
SO_2 Mass Emissions	lb/hr	3,315	1,522	-54.1
Calculated H_2O Concentration	% vol	14.40	12.40	-13.9
Measured CO_2 concentration	% vol	11.88	12.35	4.0
Calculated CO_2 concentration	% vol	13.06	13.04	-0.2
CO_2 Mass Emissions (Measured CO_2)	klb/hr	1,229	1,232	0.2
CO_2 Mass Emissions (Calculated CO_2)	klb/hr	1,352	1,301	-3.8
CEM CO_2 Mass Emissions	klb/hr	1,249	1,251	0.2
CO_2/Carbon in Coal	%wt/%wt	0.484	0.471	-2.9
Flue gas flow rate	kacfm	2,017	1,860	-7.8
	klbs/hr	6,793	6,562	-3.4
Calculated CEM Heat Input	MBtu/hr	5,694	5,525	-3.0

For preliminary tests conducted with dried coal mass and volumetric flow rates of flue gas were 3.4 and 7.8 percent lower compared to the wet coal. Lower flow resulted in lower fan power requirements and allowed higher portion of the flue gas to be scrubbed in the flue gas desulphurization reactor (FGD) further reducing SO_2 and Hg emissions. Continuous Emissions Monitor (CEM) heat input, calculated by using actual values of CO_2 F-factor (F_c factor), CO_2 concentration, and flue gas flow rate, was approximately 3 percent lower for dried coal compared to the wet coal.

Hg Speciation and Emissions

Flue gas mercury concentration and changes in speciation were determined for wet coal baseline tests and preliminary tests with dried coal employing semi-Continuous Emission Monitors (sCEMs). Results are summarized in Table E-2.

Table E-2: Measured Vapor-Phase Hg Concentration at Various Points: Wet Coal Baseline and Preliminary Tests with Dried Coal

sCEM Measurements				
Measurement Location	**Measured Quantity (sCEM)**	**Units**	**Wet Coal Baseline Average**	**Dried Coal Average**
APH Inlet	Total Hg	μg/dNm^3 at 3% O_2	**19.2**	**15.3**
	Elemental Hg	μg/dNm^3 at 3% O_2	18.0	15.3
	Oxidized Hg	% of Hg^T	**11**	**1**
FGD Inlet	Total Hg	μg/dNm^3 at 3% O_2	**16.0**	**13.7**
	Elemental Hg	μg/dNm^3 at 3% O_2	11.6	8.0
	Oxidized Hg	% of Hg^T	27	42
FGD Outlet	Total Hg	μg/dNm^3 at 3% O_2	**13.1**	**9.5**
	Elemental Hg	μg/dNm^3 at 3% O_2	12.3	8.9
	Oxidized Hg	%	**7**	**6**
FGD Bypass	Total Hg	μg/dNm^3 at 3% O_2	**14.82**	**14.40**
	Elemental Hg	μg/dNm^3 at 3% O_2	11.57	9.70
	Oxidized Hg	% of Hg^T	22	33
Stack	Total Hg	μg/dNm^3 at 3% O_2		**8.7**
	Elemental Hg	μg/dNm^3 at 3% O_2		8.3
	Oxidized Hg	% of Hg^T		**5**

For dried coal, average total mercury (Hg^T) concentration at the FGD inlet decreased by approximately 14 percent relative to the wet coal, while Hg speciation (oxidized mercury/total mercury) increased from 27 to 42 percent. This change in speciation increased mercury capture in the FGD.

For dried coal, average Hg^T concentration at the FGD outlet decreased by approximately 27 percent relative to the wet coal, resulting in an increase in native Hg^T removal across the FGD from 15 to 35 percent.

Most of the oxidized mercury (Hg^{2+}) is removed in the FGD. In case of wet coal, Hg^{2+} was reduced from 27 to 7 percent, while for dried coal reduction in Hg^{2+} was from 42 to 6 percent. This corresponds to an increase in native Hg^{2+} removal across the FGD from 74 to 86 percent. Native Hg^T removal across APH, ESP, and FGD for dried coal was approximately 23 percent higher compared to wet coal.

Re-emissions of elemental mercury (Hg^0) were reduced from 33 percent for wet coal to 17 percent for dried coal, resulting in lower Hg^T emissions.

Reduction in Hg^T concentration measured by the plant Hg CEM monitor was approximately 40 percent. Accounting for 3 percent reduction in flue gas flow rate, gives reduction in Hg mass emissions rate of 41 percent relative to the wet coal baseline.

Commercialization

A commercialization plan was agreed to and signed as part of the original agreement between Great River Energy and the Department of Energy. Nearly half the global coal reserves are low-rank and, from the start, there has been much global interest. In 2009, an agreement was signed by GRE and WorleyParsons giving the engineer exclusive right to license DryFining™, the trademark name for the technology.

To date, Great River Energy has had 63 confidentiality agreements signed by vendors and suppliers of equipment and 15 utilities. GRE has had agreements signed from companies in Canada, Australia, China, India, Indonesia, and Europe.

A secondary market for DryFining™ is believed to be the plants who switched from a higher sulfur eastern bituminous to low sulfur western PRB but lost a level of performance due to the lower heating value of the PRB coal. DryFining™ should be able to recover that margin.

1. INTRODUCTION

1.1. Background

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 lignites. European and Australian lignites (or brown coals) may contain 60 percent moisture or more. Some bituminous coals, such as Illinois coals are washed to remove impurities, such as ash, sulfur, and Hg, reduce emissions, and improve HHV. Washed coals may contain significant amounts of water (mostly as surface moisture) and need to be dewatered to improve handling and higher heating value (HHV), and dried to further improve HHV.

When high-moisture lignites 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 the 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 emissions.

According to the World Coal Institute, recoverable reserves of lignite and sub-bituminous coals are large, with U.S. having approximately 140 billion tons (52% of domestic coal reserves), Russia 110 billion tons, China 50 billion tons, and Germany and Australia about 40 billion tons of recoverable reserves. Additionally, according to the U.S. Energy Information Agency use of western coals will continue to increase beyond the year 2030.

Countries with large resources of high-moisture low-quality coals are developing coal dewatering and drying processes. Most of these drying processes depend on high-grade or process heat to reduce coal moisture content, or employ complex equipment layout using expensive materials to recover 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. A review of thermal drying technology is presented in [2].

Implementation of carbon capture and sequestration (CCS) technology at power plants using low-rank, high-moisture coals, underscores the need for efficient, inexpensive coal drying technology to recover a portion of efficiency loss incurred by compression of carbon dioxide (CO_2), air separation (in case of oxy-fuel combustion, or oxygen-blown gasification), or regeneration of the CO_2 scrubbing reagent (in post-combustion CO_2 capture). Therefore, new power plants, employing CCS and using high-moisture fuel would benefit from thermally dried coal.

Also, as shown in Figure 1, in addition to steam parameters (pressure and temperature), fuel quality (moisture content) has a large effect on net unit heat rate. While net unit heat rate for a power plant fired by bituminous coal will improve by raising steam parameters from supercritical to ultra supercritical conditions, for high-moisture lignite the improvement is much smaller. Therefore, lignite-fueled ultra supercritical power plants would benefit from coal drying and should be designed with an integrated coal drying system.

A process that uses low-grade heat to evaporate a portion of fuel moisture from the lignite feedstock in a fluidized bed dryer (FBD) was developed in the U.S. by a team led by Great River Energy (GRE). The demonstration is being conducted with Department of Energy (DOE) cost share under DOE Award Number: DE-FC26-04NT41763.

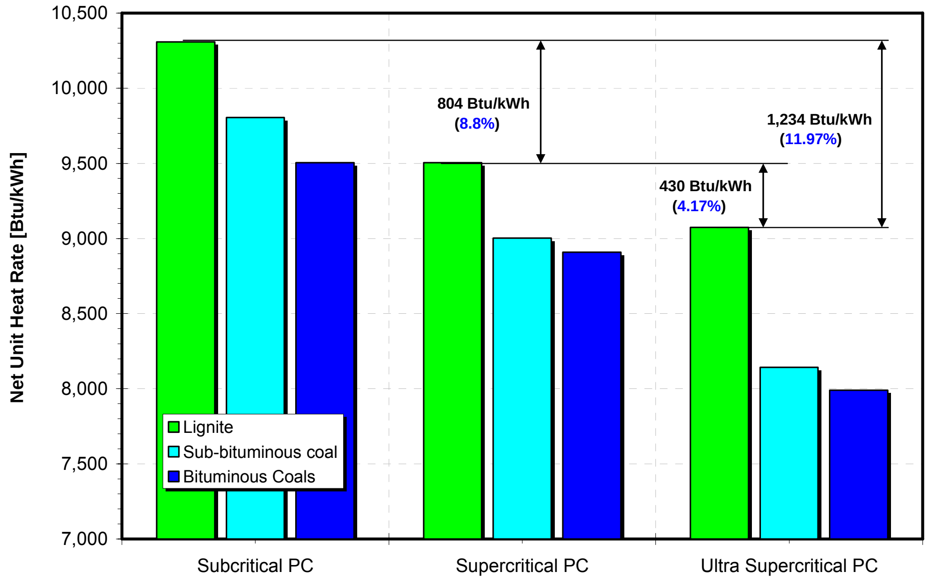

Figure 1: Effect of Fuel Quality and Steam Parameters on Net Unit Heat Rate

A moving bed fluidized bed coal dryer was selected for this project due to its good heat and mass transfer characteristics which result in a much smaller dryer, compared to a fixed bed design and high throughput which reduces number of required dryers. The FBD size, number of dryers, flow rate of fluidizing air and the power required to drive the fluidizing air fan are influenced by the FBD operating conditions, such as:

- Coal size
- Bed depth
- Fluidizing air temperature
- Maximum allowed bed temperature
- Heat transferred to the fluidized bed by the in-bed heat exchanger
- Amount of available heat that could be used for drying.
- Target moisture level of dried coal leaving the dryer

Higher dryer temperatures result in smaller dryer size but require a more expensive heat exchanger system, working at higher temperature levels as well as more expensive heat sources. Dryer operating parameters were optimized and matched to plant heat sources in Phase 1 of the study. Commercial dryers were designed as scaled-up versions of a prototype dryer.

1.2. Project Objectives

The objectives of GRE's Lignite Fuel Enhancement project were to demonstrate a 8.5%-point reduction in lignite moisture content (about ¼ of the total moisture content) by using heat rejected from the power plant, apply technology at full scale at Coal Creek Station, and commercialize coal drying technology in the U.S. and worldwide. Application of GRE's coal drying technology will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although existing lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution and CO_2 emissions, and improve plant economics. Furthermore, the efficiency of ultra supercritical units burning high-moisture coals will be improved significantly by using dried coal as a fuel.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station. A phased approach is used. In Phase 1 of the project, a full-scale prototype coal drying system, including a fluidized bed coal dryer, was designed, constructed, and integrated into Unit 2 at Coal Creek. Performance of the dryer and effect of drier coal on unit performance and emissions were evaluated in a series of controlled tests. The details are described in the Phase 1 report [1].

The objectives of Phase 2 of the project include design, construction and integration of full scale commercial coal drying system into Unit 2 at Coal Creek, and determination of performance improvement and emissions reduction. The coal drying system includes four commercial size moving bed FBDs per unit, conveying system to handle raw lignite, segregated, and product streams, and particulate control system.

System Commissioning and Testing

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 2010. A final performance test is planned for the fall 2010 after system optimization.

2. DESCRIPTION OF COAL CREEK STATION

Coal Creek Station (CCS) is a 1,200 MW lignite-fired power plant located in Underwood, North Dakota. The plant supplies electricity to 28 member cooperatives in Minnesota. 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 1,000°F main steam temperature and 1,005°F reheat steam temperature at a 2,520 psia throttle pressure. Three mechanical draft cooling towers are used to reject heat to environment. An aerial photograph of Coal Creek Station is presented in Figure 2.

Fuel is provided by North American Coal Corporation’s Falkirk Mine located near the plant. The plant design performance was based on an original fuel heating value specification of 6,800 Btu/lb. However, the heating value of the fuel being delivered to the plant has only been about 6,100 - 6,200 Btu/lb. The major impact of this 11 percent shortfall in heating value has been reduced boiler and unit efficiency, lost pulverizer selection flexibility, increased volumetric flue gas flow, increased station service power requirements, and higher pulverizer and coal pipe/burner operating and maintenance costs.

Figure 2: Aerial Photograph of Coal Creek Station

3. PREVIOUS WORK

During the 1990's the engineering staff at CCS began investigating alternative approaches to dealing with future emission regulations. Conventional approaches included changing fuels and/or adding environmental control equipment. This approach often results in lowering emissions at the expense of increases in unit heat rate and operating and maintenance costs. Higher heat rate results in higher required fuel heat input, higher CO_2 emissions, higher flow rate of flue gas leaving the boiler and lower plant capacity. Lower capacity is due to higher station service power requirements or limited equipment capacity. Also, increased flue gas flow rate requires a larger size of environmental control equipment, higher equipment cost and station service power. As many of these factors would be improved by restoring the performance lost to the reduced fuel HHV Coal Creek's plant staff elected to pursue fuel enhancement by reducing lignite moisture content by thermal drying.

A theoretical analysis, performed by the Lehigh University's Energy Research Center (ERC) in 1997-98, confirmed that a decrease in fuel moisture would have a large positive effect on unit performance [3]. Based on these theoretical results, CCS personnel performed test burns with partially dried lignite in 2001 to ensure whether the boiler and coal handling system could handle the partially dried lignite, and to confirm theoretical performance improvement predictions [4]. Based on laboratory testing conducted at the ERC in 2002, a fluidized bed dryer was selected as the best technology due to its high heat and mass transfer coefficients and compact size.

Previous work and project activities are summarized in Table 1.

Table 1: Previous Work and Project Activities

Time Period	**Activity**
1997-1998	Preliminary studies and concept development.
1999	Lignite-drying tests using low-temperature fixed-bed dryer.
2000	CCS Boiler modeling. Laboratory lignite drying tests. Full-scale test burns using 20,000 tons of lignite dried using low-temperature air.
2001	Fluidized bed dryer selected for coal drying due to higher efficiency, smaller size, and lower cost. Laboratory-scale FB drying tests at ERC.
2002	Application filed with DOE under the Clean Coal Power Initiative (CCPI)
2003	Application selected for negotiation with DOE. Pilot FBD built at CCS. Pilot FBD testing.
2004	Cooperative Agreement signed with DOE. Design of the prototype coal dryer and associate equipment.
2005	Construction of prototype coal dryer begins.
2006	Prototype dryer checkout and start-up. Prototype dryer performance testing. Unit performance testing. Maximum capacity testing. Data analysis and project report. August: **Phase 1 milestone**.

As indicated in the above table, U.S. Department of Energy selected the Great River Energy project entitled ”Lignite Fuel Enhancement” for Financial Assistance under Round I of the Clean Coal Power Initiative (CCPI) in 2003. This CCPI demonstration project at Unit 2 of the Coal Creek Station was administered by the DOE’s Office of Fossil Energy and managed by the National Energy Technology Laboratory (NETL). The DOE cost share in this project is $13.5 million and the corresponding CCPI project value is $31.5 million. Based on the initial test results on Unit 2, GRE has decided to build four full-scale dryers on Unit 1 also with its own funds. In order to provide uniform coal quality to all dryers, GRE decided to upgrade the front-end coal handling system with its own funds. The costs relating to upgrading of the coal handling system, Unit 1 dryers, and processing of segregated coal from dryers of both units are funded by GRE and are not part of the CCPI project.

Based on theoretical and experimental 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 moving bed fluidized bed dryer [1]. The project was executed in three stages; a feasibility stage, a prototyping stage (Phase 1), and a scale-up (commercial) stage (Phase 2).

3.1. Pilot Coal Dryer

The feasibility stage consisted of a “proof of concept” demonstration. A two-ton per hour fluidized bed pilot was constructed in the coal yard at CCS with the support of the North Dakota Lignite Council and North Dakota Industrial Commission. Testing confirmed that the dryer would indeed dry fuel as predicted by theoretical model developed by the ERC. Further, taking advantage of the inherent characteristic of bed fluidization to naturally segregate material by density, it also selectively removed heavier components, most notably iron sulfide (pyrite), rocks, stones, and tramp iron.

This segregation of sulfur-bearing minerals offered GRE the potential benefit of removing a significant proportion of sulfur from the fuel stream prior to its entering the boiler, a benefit that was subsequently confirmed in Phase 1 of the project. A similar segregation of mercury-bearing minerals was also noted. As a partially scrubbed facility, and faced with substantial capital expenditures to meet pending stringent sulfur and mercury emissions targets, this segregation benefit offered GRE an attractive alternative for emissions compliance. More information is provided in [1] and [5].

3.2. Prototype Coal Dryer (CD 26)

Experimental results obtained during the pilot plant test campaign and results of model predictions of the FBD and air preheater (APH) performance were used by a team of industry participants led by GRE and ERC to develop a prototype coal drying system. The heart of this drying system is a nominal 75 ton/hr fully instrumented, low-temperature, prototype two-stage FBD. Coal, delivered from bunker 28, is crushed to ¼" top size by a coal crusher located upstream of the dryer and fed to the first stage of the FBD by two rotary feeders. In first stage non-fluidizable material segregates to the bottom of the dryer. The segregated fraction is discharged through scrubbing boxes and air locks as a stream of higher mineral matter content and hence also higher in sulfur and mercury in comparison to the product stream. The first dryer stage accomplishes three functions: separates the fluidizable and non-fluidizable material, pre-dries and pre-heats the coal, and provides uniform flow of coal to the second stage. Coal fines, elutriated from the dryer, are collected in a particulate control system (baghouse).

The fluidizable material flows to the second stage of the dryer, where the coal is heated and dried to a desired outlet moisture level by heat supplied by the fluidizing air and an in-bed heat exchanger. The in-bed heat exchanger increases the temperature of the fluidizing (drying) air, increasing its moisture-carrying capacity. Partially dried coal, dried to the desired moisture content, is discharged from the FBD as a product stream into bunker 26, effectively converting pulverizer 26 to partially dried coal. A schematic representation of a two-stage moving fluidized bed dryer is presented in Figure 3.

The prototype coal drying system was integrated with Unit 2 heat sources. The prototype FBD operated over a range of operating conditions almost continuously from February 2006 to summer of 2009. During this period, it has processed more than 650,000 tons of raw coal at throughputs as high as 105 tons/hr, and confirmed the capability of the full-scale dryer to reduce fuel moisture to the target level. Just as significantly, the prototype FBD confirmed that the density segregation effects observed during pilot testing translated to the full-scale device. Details are provided in [1].

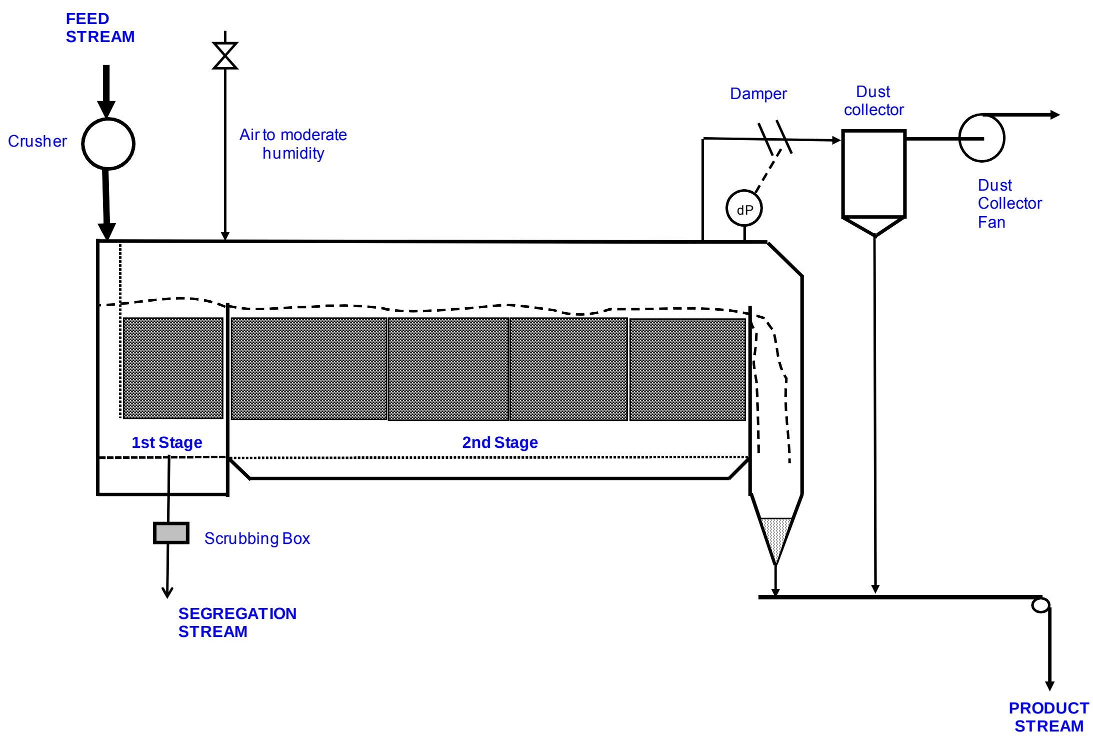

Figure 3: Prototype FBD Schematic

3.2.1. Dryer Performance

Performance tests were conducted under controlled conditions to determine dryer performance and effect of firing dried coal on boiler efficiency and unit performance. A paired-test approach was used where two consecutive performance tests were run per day: one with the prototype dryer in operation, the other with the prototype dryer off. The order of tests, i.e., dry and wet, or wet and dry was determined randomly. Such an approach minimized effects of bias errors, i.e., day-to-day variations in plant operating conditions, and other uncontrollable (extraneous) variables. Based on statistical analysis, 16 paired performance tests were conducted. CD 26 performance was also monitored during regular dryer operation, and coal quality data were collected for the time period from March to April, 2006. Results are summarized in Table 2 and presented Figures 4 and 5.

Table 2: Regular Dryer Performance: Coal Moisture and HHV

Parameter	Feed TM %	Product TM %	Change TM % Abs	Change TM % Rel
Average Total Moisture, TM	**36.78**	**28.55**	**8.23**	**22.4**
Std. Deviation	**1.26**	**1.00**	**1.07**	
Std. Deviation of the Mean	**0.34**	**0.27**	**0.30**	

Parameter	Feed HHV [BTU/lb]	Product HHV [BTU/lb]	Change HHV [BTU/lb]	Change HHV [%]
Average HHV	**6,290**	**7,043**	**752**	**12.0**
Std. Deviation	**159**	**121**	**131**	
Std.Deviation of the Mean	**43**	**33**	**37**	

The average moisture reduction, achieved during regular dryer operation, was 8.23 ± 0.6 percent. This is almost identical to the total moisture reduction achieved during the controlled performance tests. The improvement in HHV during regular dryer operation was 752 ± 74 Btu/lb. Within the accuracy of the data, this is the same improvement in HHV achieved during the controlled dryer performance tests. In conclusion, this means that dryer performance, measured during the controlled tests, is sustainable over the long-term [6]. More information on prototype dryer performance is provided in [1].

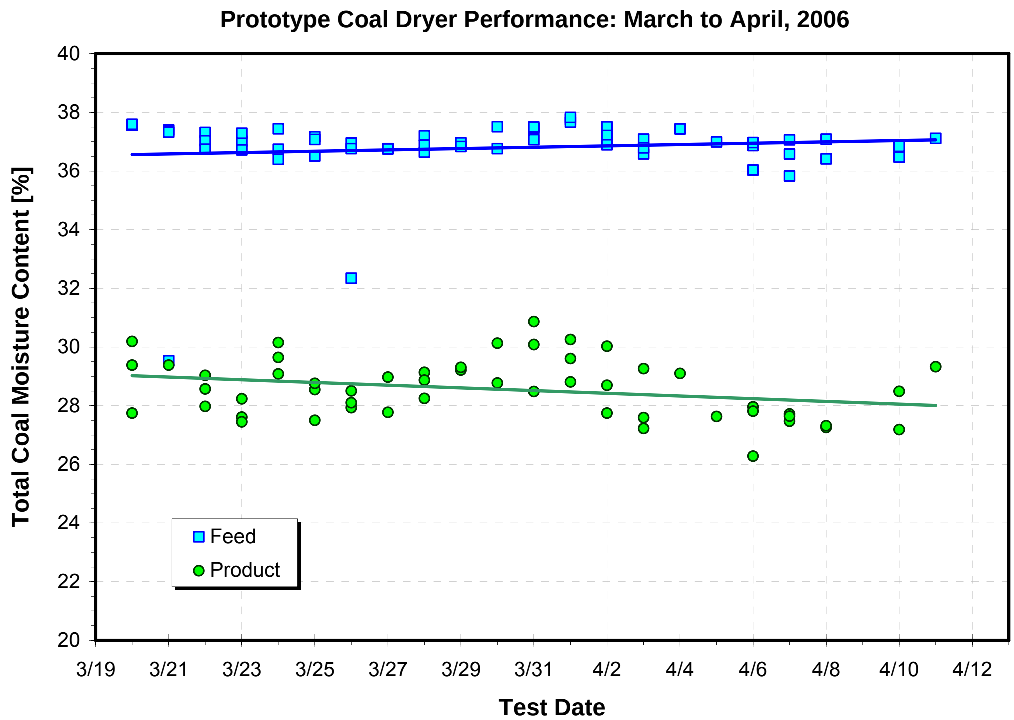

Figure 4: Coal Moisture in Feed and Product Streams Measured During Regular Dryer Operation

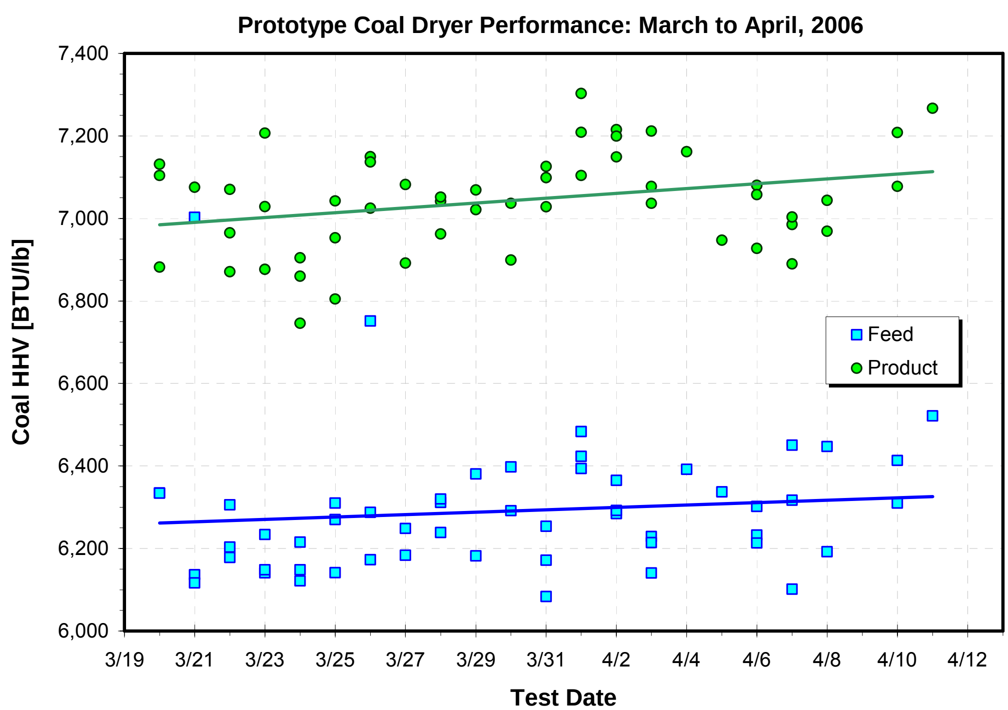

Figure 5: Higher Heating Value for Feed and Product Streams Measured During Regular Dryer Operation

3.2.2. First Stage Segregation

As discussed earlier, the non-fluidizable material sinks to the bottom of the first dryer stage, and is removed as the segregation stream. The total moisture, sulfur, and mercury content, and HHV of the feed, product, and segregation (undercut) streams, determined from samples that were collected during the May-June, 2006 time period were analyzed for sulfur and mercury content, and HHV. Results are summarized in Table 3 were the sulfur, mercury, and HHV of the segregation stream are presented as percentage of the feed stream. Mass balances of sulfur and mercury around the FBD are presented in Figures 6a and 6b. The results show that approximately 30 percent of sulfur and mercury in the feed stream entering the dryer are removed in the first stage and discharged as the segregated stream. Small errors in sulfur and mercury mass balance are caused by uncertainties in measurement of sulfur and mercury content in coal.

Table 3: Sulfur and Mercury Removed by the First Stage and HHV Content of the Segregation (Undercut) Stream

Undercut Stream			
Test	**S**	**Hg**	**HHV**
	% of Feed	% of Feed	% of Feed
1	22.5	21.9	10.4
2	29.3	26.5	9.9
3	34.5	45.8	9.7
4	21.2	23.3	10.3
5	19.4	25.2	10.5
6	36.0	36.3	10.2
7	28.2	24.6	10.3
8	25.7	31.5	10.2
9	32.5	42.0	10.0
10	27.4	35.9	10.4
Average	**27.7**	**31.3**	**10.2**

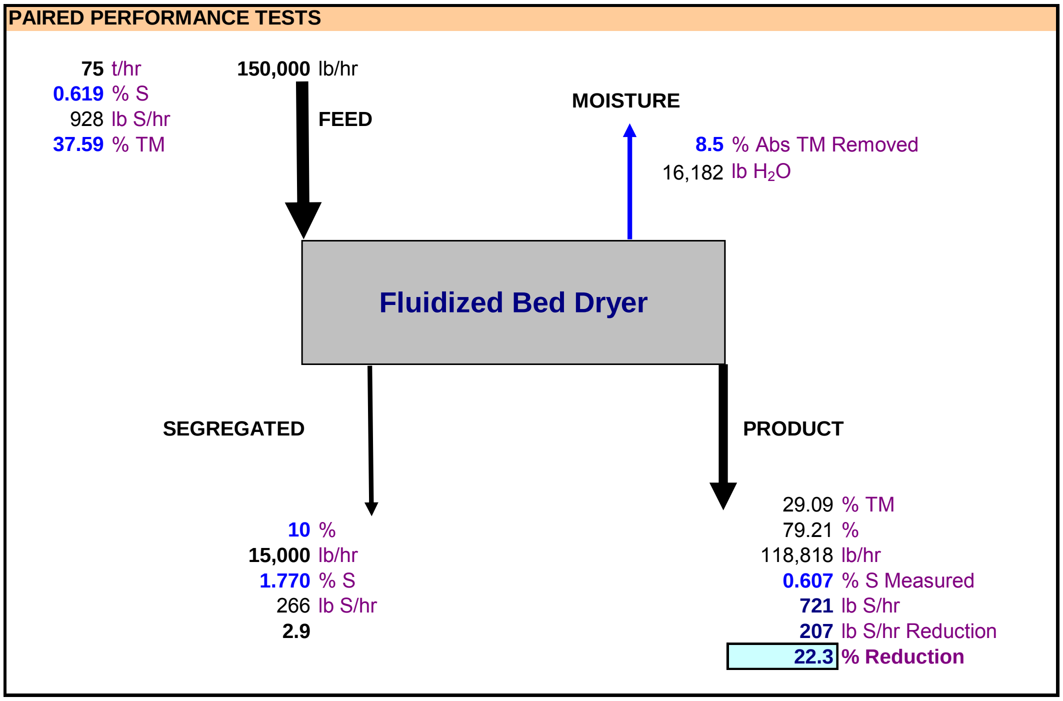

Figure 6a: Mass Balance of Sulfur around the FBD

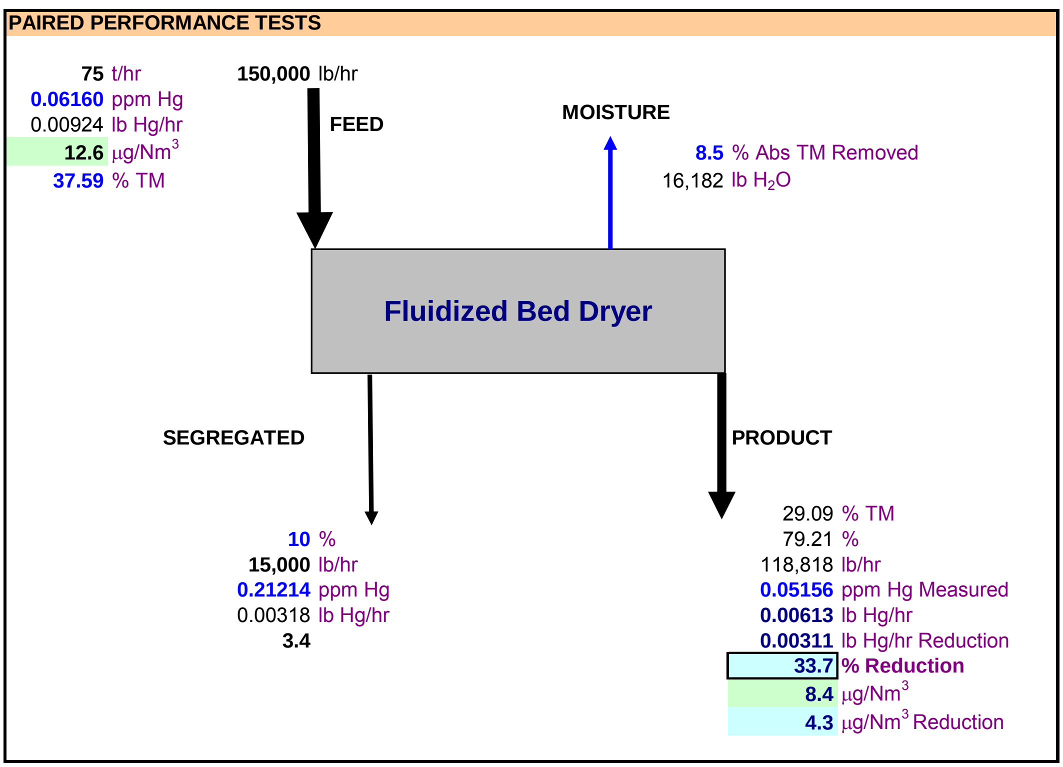

Figure 6b: Mass Balance of Mercury around the FBD

The segregation stream contains approximately 10 percent of the inlet HHV. Additional processing of the segregation stream is needed to further concentrate sulfur and mercury and reduce the HHV content. This additional processing of segregation stream is accomplished by air jigs incorporated in the full-scale (commercial) coal drying system. The cleaned segregation stream is returned to the product stream.

3.2.3. Effect of CD 26 on Unit Performance and Emissions

With the prototype coal dryer (CD 26) in service and operating at a nominal coal feed of 75 t/hr, dried coal represents approximately 14 percent of the total coal flow rate supplied to the boiler. Therefore, the effective reduction in coal moisture of a blend of partially dried and wet coals is approximately 1.14 percentage-points while improvement in HHV is 103 Btu/lb or 1.63 percent. With commercial drying system in service, processing 100 percent of coal input, reduction in coal moisture would be 8.5 percentage-points and improvement in HHV 800 Btu/lb. Changes in operating and performance parameters relative to wet coal are summarized in Table 4 for the prototype-scale and commercial full-scale drying systems.

Table 4: Change in Operating and Performance Parameters Relative to Wet Coal

Change in Parameter Relative to Wet Coal	**Units**	**Prototype-Scale System**[1]	**Commercial-Scale System**[2]
Change in coal flow rate	%	-1.83	-14
Change flue gas flow rate	%	-0.55	-3.9
Change in boiler efficiency **excluding** fan room coils	%-point	0.37	1.70
Change in boiler efficiency including fan room coils	%-point	0.80	2.13
Change in net unit heat rate **excluding fan** room coils	%	0.37	2.05
Change in net unit heat rate including fan room coils	%	0.71	2.39

[1] Measured
[2] Projected/calculated

Reductions in NO_x, SO_x, and CO_2 emissions, measured by the plant CEM during the prototype dryer performance tests, are 7.5, 1.93, and 0.37 percent, respectively [1]. Reduction in NO_x emission is achieved due to reduced PA flow to mill 26, while reduction in CO_2 and Hg emissions is assumed to be proportional to improvement in net unit heat rate. With the commercial coal drying system in service reduction in NO_x emissions is expected to exceed 20 percent.

The percentage reduction in SO_x emissions is larger than the percentage the reduction in flue gas mass flow rate (0.55 percent). This is because with a lower flue gas flow rate, the flue gas bypass around the scrubber decreases, resulting in a higher SO_x removal. With 100 percent partially dried coal fired in the boiler, the flue gas flow rate to the wet scrubber will be reduced by approximately 4 percent on weight basis, resulting in additional reduction in SO_x emissions.

Since the segregation stream was mixed with the product stream in the prototype coal drying system, the benefit of density segregation on sulfur and mercury reduction was not realized. If the segregation stream were not mixed with the product stream, the mass flow rates of sulfur and mercury to the boiler would be reduced, resulting in lower emissions of these pollutants.

In a full-scale commercial coal drying system segregation stream will be further processed and cleaned by air jigs (pulsed fluidized beds) before mixing with the product stream. This would result in substantial reduction in sulfur and mercury into the boiler. The reduction in SO_x emissions is expected to exceed 40 percent, while Hg reduction is expected to be in the 35 to 40 percent range.

Reduction in Hg will be higher compared to SO_x due to a change in Hg speciation in a wet scrubber caused by lower flue gas moisture content with dried coal. A 8.5 percentage-point reduction in fuel moisture would reduce flue gas moisture content by 2.5 percentage-points. According to theoretical predictions [1], this would reduce elemental mercury (Hg^{o}) content in the flue gas by approximately 20 percent. In other words, with a partially dried coal, approximately 20 percent more elemental mercury will be oxidized compared to wet coal. The oxidized mercury (Hg^{+2}) is water-soluble and is expected to be removed in the wet scrubber.

PART 1: FULL-SIZE COAL DRYING SYSTEM AND ITS PERFORMANCE

Background

Following the successful completion of Phase 1 and evaluation of the prototype, the project participants decided to proceed with the Phase 2 full-scale demonstration of the drying system on Unit 2 at CCS. The very promising results of the prototype FBD led the Board of Great River Energy to direct that the full-size drying system be installed on both units at Coal Creek. To a large extent, this decision was driven by the prospects of large offsets in capital expenditures for additions to the flue gas desulfurization systems, for mercury control, and for NO_x emissions curtailment.

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 good reliability. In accordance with the Boards' directive, four additional coal dryers were procured and installed on Unit 1 concurrent with the Unit 2 installation. Modification and commissioning of both units was completed in December 2009. Emissions and performance testing is planned for spring 2010.

4. COAL CREEK FULL-SIZE COAL DRYING SYSTEM

4.1. System Description

Although, similar to the prototype coal drying system, thermal integration of the full-scale coal drying system with plant heat sources is different. Detailed description of thermal integration is subject to patent review and, therefore, cannot be disclosed at this time in a public document.

4.2. Coal Crushing and Conveying System

Raw coal to both units is crushed to ¼" top size by four crushers located in a newly constructed crusher building. Crushers are fed by a new surge hopper. Coal to the surge hopper is delivered by two new conveyers from an existing 440 ton bin fed by existing conveyers 911 and 912. Crushed coal is stored in a newly constructed bin and fed by conveyers 943 and 944 to a new wet coal transfer hopper 95. The transfer hopper provides wet crushed coal to Units 1 and 2. For Unit 1, coal from the transfer hopper is delivered to dryer bin 11 by conveyer 151, while conveyer 152 feeds dryer bin 13. Coal from the dryer bin 11 is fed to coal dryers 11 and 12 (CD 11 and CD 12) by two screw feeders per dryer. Bin 13 provides coal to coal dryers 13 and 14 (CD 13 and CD 14) by two screw feeders per dryer. Coal feed arrangement for Unit 2 dryers mirrors dryer feed arrangement for Unit 1.

For Unit 1, dried coal (product stream) from the dryer is discharged to a dry coal conveyer 153, and transferred to existing conveyers 961 and 962. The segregation stream is discharged to a segregated coal conveyer 154, which transports it to air jig for further cleaning. Alternatively, the segregation stream can be discharged to the dry coal conveyer 153. The system arrangement for handling product and segregation streams for Unit 2 mirrors the arrangement for Unit 1. The process diagram of the coal feed, product, and segregation stream handling systems is presented in Figure 7.

4.3. Full-Size Fluidized Bed Coal Dryer

Due to its high heat and mass transfer characteristics, a fluidized bed dryer is a good choice for drying coal to be burned at the same site where it is dried. The dryer can be of single-stage or multi-stage design, with the stages contained in one or more vessels. As confirmed in Phase 1 of the project [1], multi-stage design allows maximum utilization of fluidized bed mixing, segregation and drying characteristics.

While a two-stage FBD design, where the bed volume is divided in two parts, was employed in Phase 1 of the project, the full-size commercial FBD was designed and constructed with three stages. Similar to the prototype dryer, the first stage of the full-size dryer occupies approximately 20 percent of the dryer volume, and is designed to facilitate density segregation and removal of segregated material through multiple scrubbing boxes and air locks. In normal operation, the segregation stream is discharged to the segregated coal conveyer 154. All eight dryers were manufactured by Heyl & Patterson, Inc.

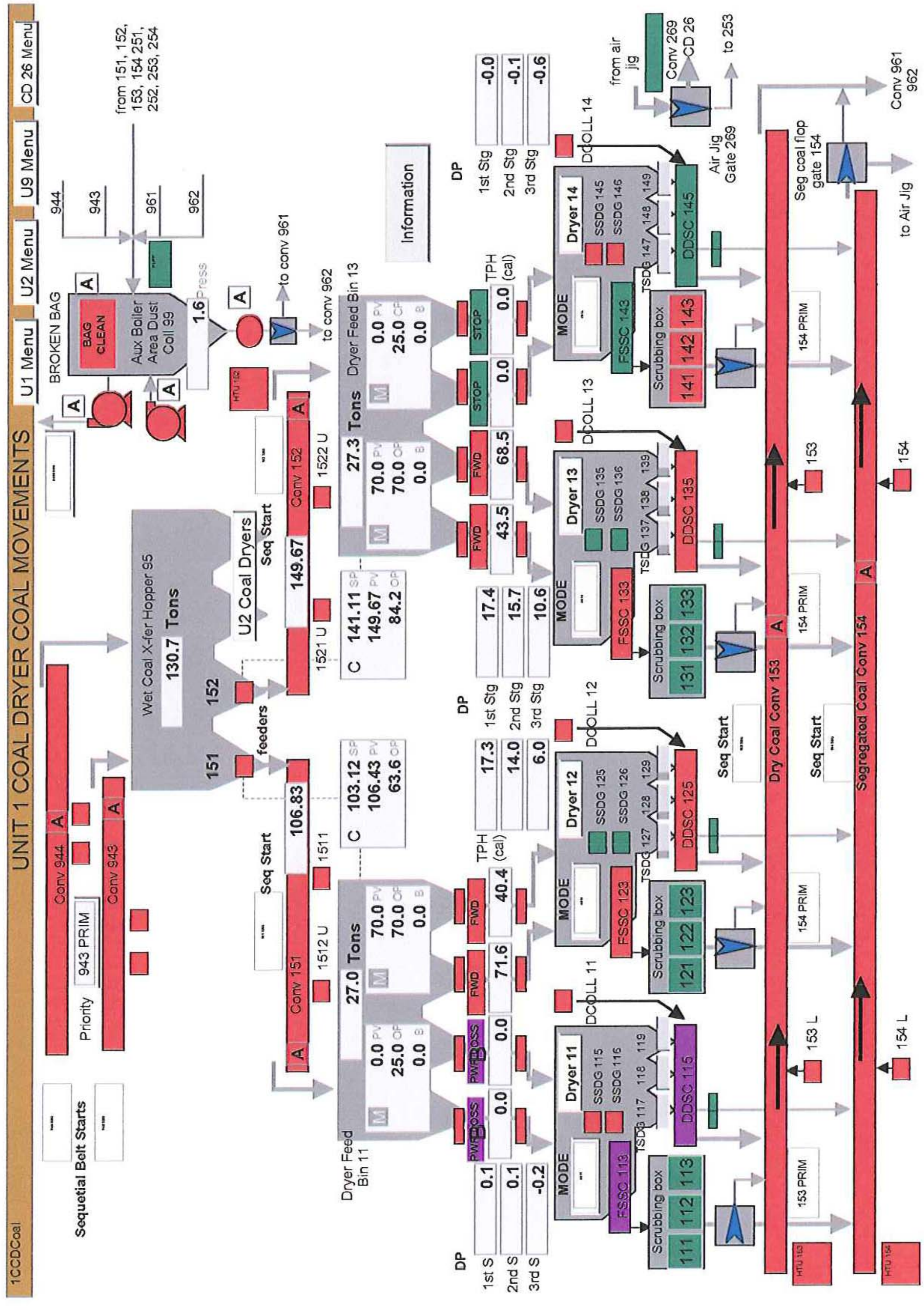

Figure 7: Coal Feed, Product, and Segregation Streams Handling System

All three stages of the FBD are fluidized by air. Coal fines, elutriated from the FBD and collected by a dust collector (baghouse), are returned to the dryer. Each FBD is equipped with its own baghouse. De-dusted fluidizing air streams leaving baghouses of two adjacent FBDs are combined and discharged through a common dryer stack into the atmosphere.

At nominal coal feed rate, four dryers supply 450 t/hr of dried coal to one unit. For feed coal moisture content of 38 percent and nominal feed rate target product moisture content is 29.5 percent. At maximum feed rate, product moisture content is 30.6 percent, approximately 0.9%-point higher compared to nominal flow.

The average predicted bed temperature in the 1st and 2nd dryer stages is approximately 124°F. The maximum predicted bed temperature in the 2nd dryer stage is approximately 137°F. Relative humidity of fluidizing air leaving the dryer is in the 98 to 100 percent range.

4.4. Instrumentation

The full-size commercial coal drying system at Coal Creek is fully instrumented for process monitoring, diagnostic and control, and determination of dryer performance. Plant instrumentation is used to collect information on plant process parameters required to determine boiler efficiency, turbine cycle heat rate and net heat rate. Prior to performance testing, loop checking was performed for critical instruments.

Measured process variables on the coal side include crusher power, feed rate of crushed coal to Units 1 and 2, mass of coal in wet coal transfer hopper 95, feed rate of individual conveyers to dryer feed bins, mass of coal in each dryer feed bin, feed rate of screw feeders feeding individual dryers, flow rate and composition of dried coal, and flow rate of segregated coal stream to the air jigs. Composition of dried coal is measured in real time by two nuclear analyzers (one analyzer per unit), based on prompt gamma neutron activation analysis (PGNAA). Because the nuclear analyzer cannot measure water content in coal, a separate microwave-based instrument is used for on-line measurement of coal moisture content. Also, automatic coal samplers located in crusher building collect coal samples which are analyzed by the plant coal laboratory for composition and HHV.

Measured process variables on the air side of each FBD include flow rate, pressure and temperature of fluidizing air to the dryer stages, pressure drop across the distributor plate and bed, temperature of wet fluidizing air in the dryer freeboard area (freeboard temperature), air temperature at the baghouse inlet and outlet, baghouse pressure drop, flow rate of dilution air, and other air flow rates. CO concentration in the de-dusted air stream leaving the baghouse, and flow rate, temperature, and pressure of fluidizing air flow.

An array of thermocouples measures bed and freeboard temperature in each FBD. Thermocouples for measuring bed temperature are located four inches above distributor plate. Temperatures were measured during preliminary dryer performance testing conducted in January 2010. Bed temperature is lowest in the 1st dryer stage then gradually increases through the dryer.

Other measured quantities include process variables needed for controlling heat input to the dryer. Measured process parameters include flow rate, temperature (in and out of the in-bed heat exchanger) and pressure of the circulating water (heat transfer fluid).

4.5. Process Control

Operation of the full-size commercial coal drying system at Coal Creek is completely automated, including the startup, shutdown, and emergency shut-down procedures. The logic for controlling heat input to the dryer is similar to control logic used for the prototype dryer [1].

Dimensionless heat input x is calculated as:

$x = Q_1/Q_2$ Eqn. 1

where quantity Q_1 represents heat input to the dryer and Q_2 heat demand of the dryer.

Different values of parameter x correspond to different levels of coal moisture removal. Theoretically $x = 1$ corresponds to target moisture removal of 8.5 percentage-points at design flow rate of 125 t/hr and inlet coal moisture content of 38 percent. Since inlet coal moisture content and coal temperature vary, and measurement of process variables is not always 100 percent accurate, the actual value of x required to achieve target moisture removal varies. To deal with this variability, the operator enters set-point value of x (x_{SP}). As long as $x \neq x_{SP}$, during startup, shut-down, or transient operation when coal feed rate to the dryer varies, a control algorithm is adjusting flue gas bypass flow rate until $x = x_{SP}$. This simple control algorithm works very well in practice.

5. TEST RESULTS

5.1. Full-Size Coal Drying System and Dryer Commissioning

The objective of commissioning of the full-size commercial coal drying system was to supply 100 percent refined (dried and cleaned) coal to Coal Creek Units 1 and 2 to meet or exceed the burn rate of both two units for a 24-hour period. A 24-hour test began at 5:45 AM on Saturday 12/19/2009 when feeders, supplying coal from existing 440 ton lignite bin to crushers 91 and 92, were locked out and wet coal was directed to the new surge hopper feeding four new crushers providing wet crushed coal to the commercial coal drying system for Units 1 and 2. Scales on existing conveyers 913 and 914, providing wet coal to Units 1 and 2, indicated wet coal to both units stopped at 5:49 AM.

To prove that full-size commercial coal drying system is meeting 100 percent of the plant coal burn requirements, in-house inventories were established at the beginning and end of the 24-hour period. Bunker and Transfer Hopper 91 levels were recorded. If ending inventory exceeds starting inventory and only refined coal is supplied to Units 1 and 2 for duration of the 24-hour test this proves that the full-size coal drying system is capable of meeting coal burn requirements for Coal Creek Generating Station. During system commissioning all eight FBDs were in operation with air jigs in service. According to the test data, coal inventory at the end of the test exceeded starting inventory by over 800 tons over a 24-hour period proving that commercial coal drying system is capable of meeting coal burn requirements of both units at Coal Creek.

Operating parameters for individual FBDs during commissioning are compared in Figures 8 and 9. The total average coal flow delivered by all eight dryers was 1,005 t/hr. Except for CD 12 actual feed rate was close to the design value (125 t/hr), see Figure 8.

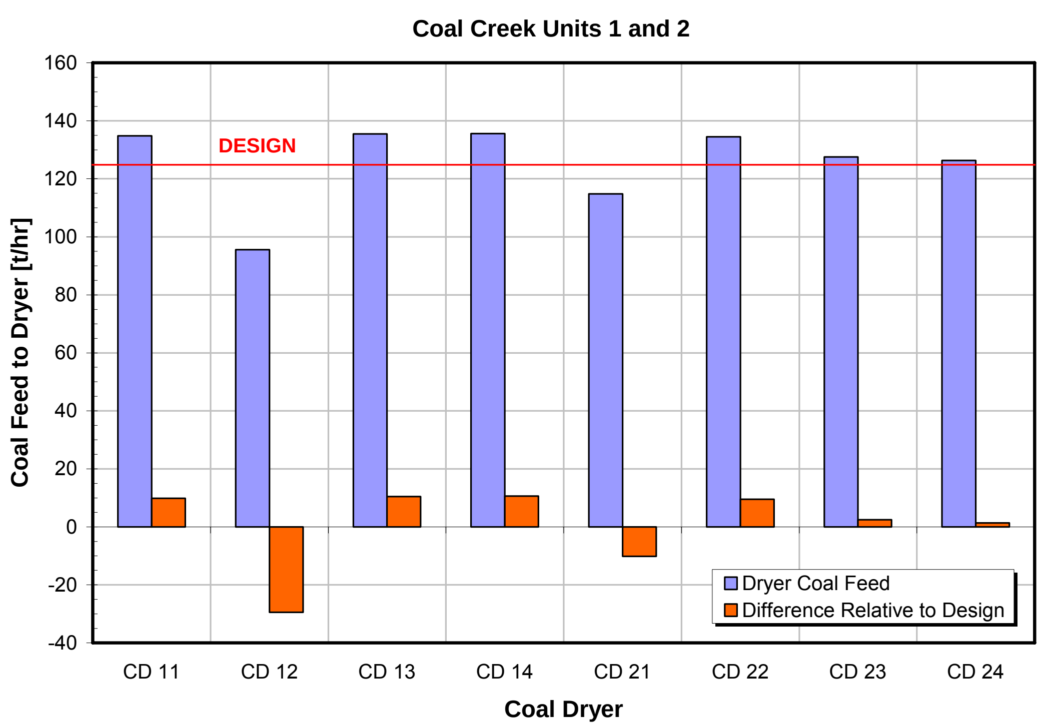

Figure 8: Average Coal Feed to Coal Dryers during Commissioning

Fluidizing air flow to individual coal dryers is presented in Figure 9. Again, except for CD 12 actual fluidizing air flow was close to the design value (360 klb/hr).

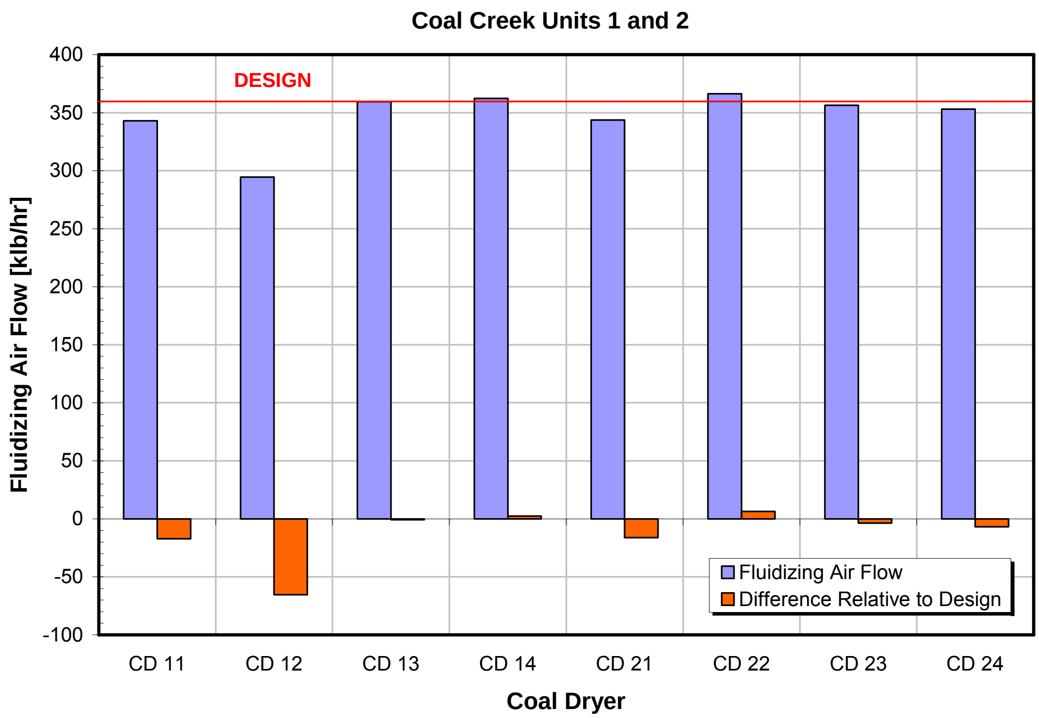

Figure 9: Average Fluidizing Air Flow to Coal Dryers during Commissioning

For all coal dryers the temperature of fluidizing air was below volatization temperature, which was confirmed by emissions testing on dryer stacks.

5.2. Dryer Operation and Performance

Functional tests of coal dryer 11 (CD 11) were performed in January 2010 to establish preliminary information on the dryer and baghouse operation and performance during controlled test conditions. Four tests were performed with coal feed rate of 132 to 134 t/hr and heat input to the dryer at 70 and 85 percent of design value (x = 0.70 and 0.85). Coal dryer 12 (CD 12) was shut down to allow measurement of coal feed to CD 11 using coal scale on conveyer 151. The actual heat input values determined from test data were 69 and 85 percent.

Duration of each test was two hours. Heat input to the dryer for Tests 3 and 4 was kept constant at 85%. Manual samples were taken from the coal feed, product, and segregated streams and analyzed for composition and HHV. Also, flow rates of raw coal feed, fluidizing air, and segregation stream to air jigs, were measured during Tests 1 to 3.

Average bed temperature in the 1st and 2nd dryer stages increased as heat input to the dryer was increased. For 85 percent heat input, the average 2nd stage bed temperature was approximately 30°F higher compared to the average 1st stage bed temperature. As measurements show, bed temperature is lowest in the 1st dryer stage, and then increases through the dryer.

Short proximate analysis was performed on manual samples obtained from the feed, product, and segregation streams. Higher heating value was also determined. Results are presented in Figures 10 to 15. Total moisture (TM) content in sampled streams is presented as a function of heat input to the dryer in Figure 10. TM decreased as heat input to the dryer was increased. For Tests 2 and 3 TM content in the product stream was 30.2 percent. Considering that heat input to the dryer was 85 percent of design value, moisture content in the product stream compares favorably to the target value of 29.5 percent. Moisture content in the feed stream was constant, close to 38 percent. As expected, moisture content in the segregation stream was slightly lower (approximately 1 percentage point) compared to the feed stream. HHV values for the feed, product and segregation streams are presented in Figure 11 as functions of heat input to the dryer. HHV values for the feed and segregated streams were constant at approximately 6,300 and 6,600 Btu/lb. Although coal moisture content in the segregation stream is only about 1 percentage-point lower compared to the feed stream, HHV is higher by 300 Btu/lb. This can be explained by lower ash content in the segregation stream (see Figure 12) compared to the feed and product streams.

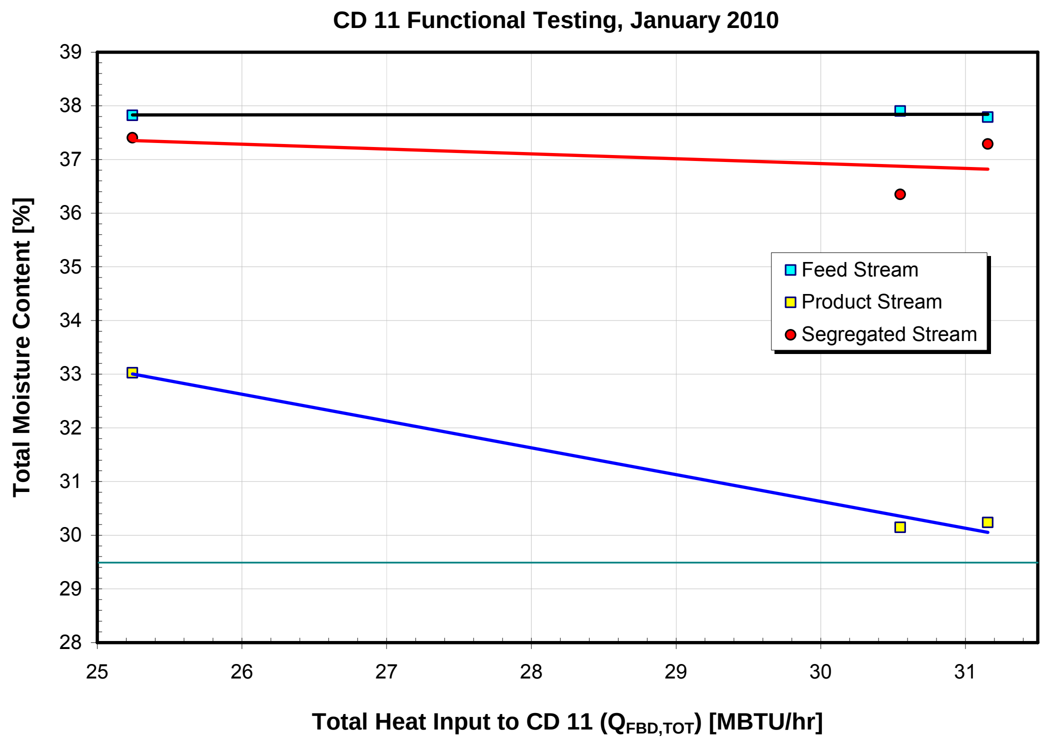

Figure 10: Total Moisture Content in Feed, Product, and Segregation Streams

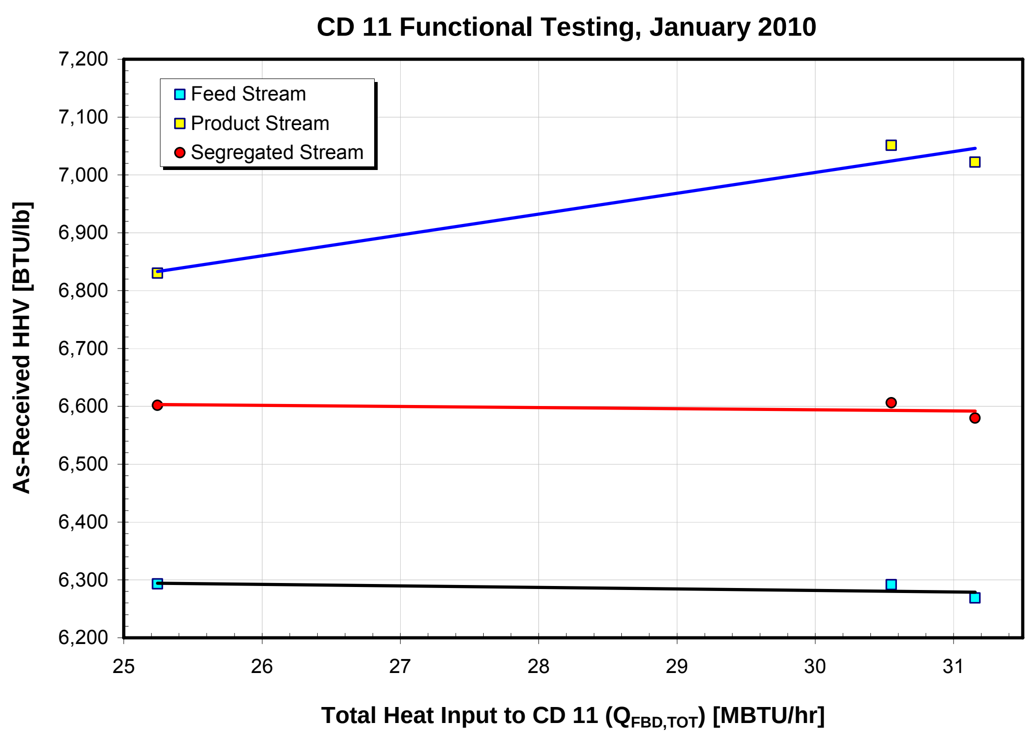

Figure 11: As-received HHV for Feed, Product, and Segregated Streams

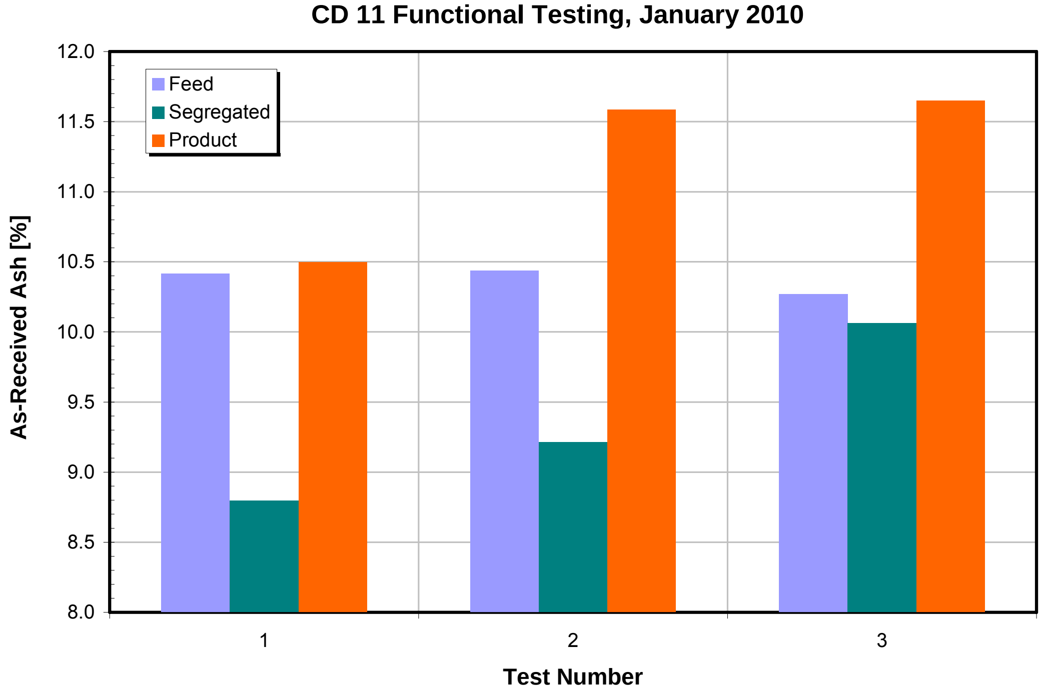

Figure 12: As-received Ash Content in Feed, Product, and Segregated Streams

Most of coal fines are elutriated in the first dryer stage resulting in lower ash content in the segregation stream. Elutriated fines, captured by the baghouse, are returned to the dryer, resulting in increased ash content in the product stream compared to segregation stream. For the product stream HHV increased as coal moisture content was reduced.

Sulfur content on the as-received and moisture-free bases in the feed, segregation, and product streams, determined from manual coal grab samples taken during Tests 1, 2 and 3 is presented in Figures 13 and 14. Similar to the prototype dryer (CD26), sulfur content in the segregation stream is considerably higher (especially when expressed on the moisture-free basis) compared to the feed and product streams. Also, sulfur content in the product stream is lower compared to the feed stream. These results show that density segregation of the sulfur-bearing materials (such as pyrites) is occurring in the full-size (commercial) coal dryer.

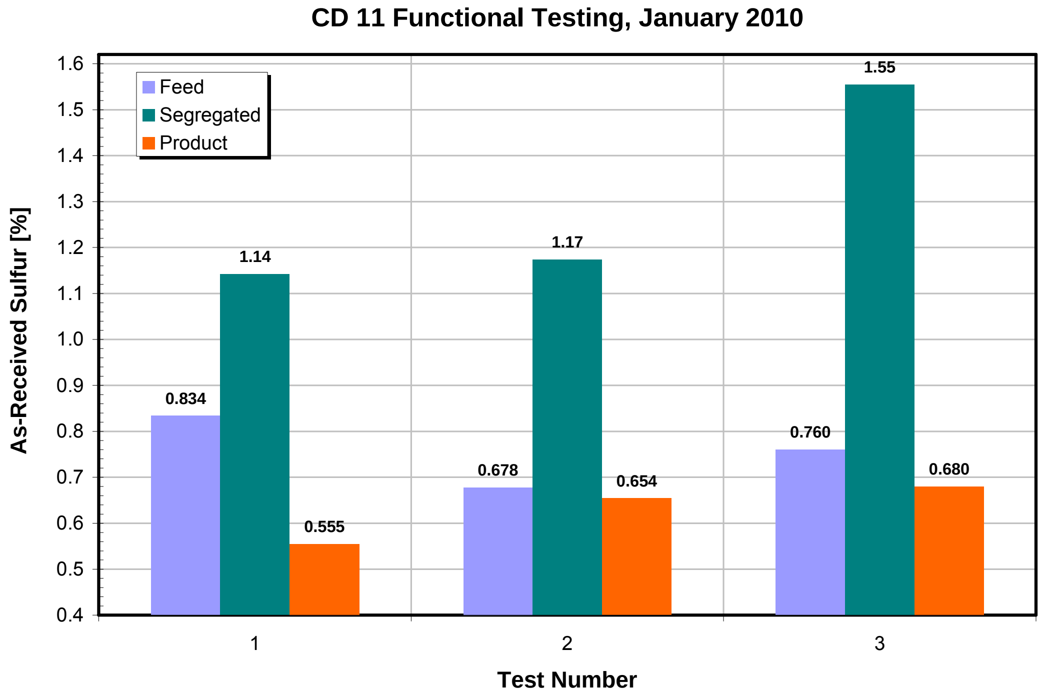

Figure 13: Sulfur Content on As-received Basis in Feed, Segregated, and Product Streams

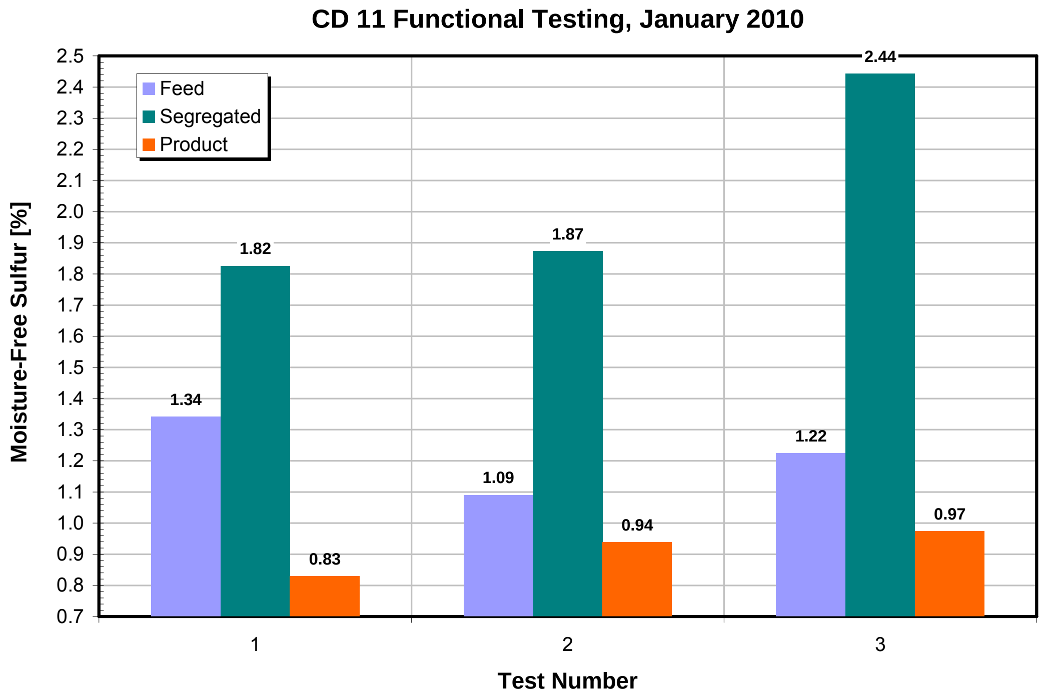

Figure 14: Sulfur Content on As-received Basis in Feed, Segregation, and Product Streams

The sulfur mass balance for CD 11 and Test 2 is presented in Figure 15. Results show that approximately 33 percent of sulfur from coal is removed by density segregation in the 1st dryer stage. This is higher compared to the prototype coal dryer results (22 percent sulfur removal, see Figure 6) because the flow rate of segregation stream measured during Test 2 was significantly higher compared to the CD 26 tests due to higher-than-design fraction of oversized material leaving coal crushers. A small error in sulfur mass balance is caused by uncertainties in measurement of sulfur content in coal.

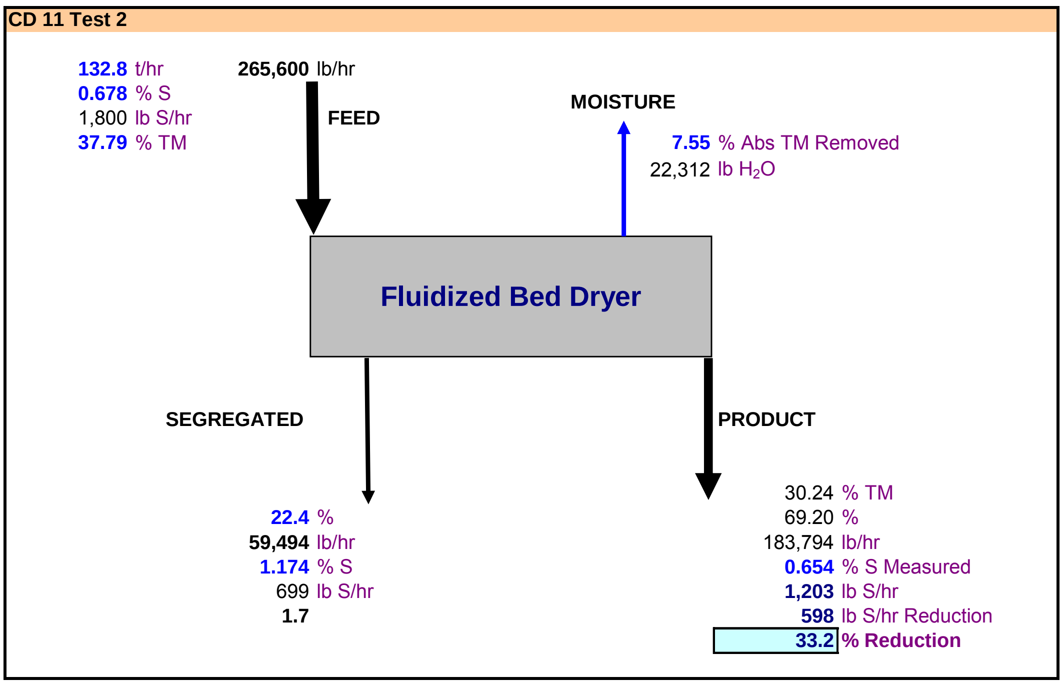

Figure 15: Mass Balance of Sulfur for CD 11 -Test 2

Measures are being taken to reduce flow rate of oversized material and, consequently reduce flow rate of segregated material discharged from the 1st dryer stage. With flow rate of segregation stream of 10 percent, approximately 22 percent of sulfur from coal will be removed from the 1st dryer stage by density segregation (same as for the prototype coal dryer).

PART 2: UNIT PERFORMANCE AND EMISSIONS

6. TEST PROCEDURE

Two series of controlled tests were performed at Units 1 and 2 at Coal Creek with wet and dried lignite to determine and effect of dried lignite on unit performance, emissions and operation. Wet lignite was fired during the first, baseline, test series. The second test series was performed after the commercial coal drying system was commissioned, using dried and cleaned lignite where segregation stream was cleaned by air jigs before being mixed with the product stream. When Spiritwood , a Combined Heat and Power (CHP) plant, owned by GRE, begins operation, cleaned segregation stream will be dried in CD26 before being shipped to Spiritwood as beneficiated fuel (see Section 9).

The unit was kept at steady state operating conditions during the test. Turbine throttle pressure was set at 2,520 psig with control valves 100 percent open (VWO), main steam temperature at 1,000°F, and reheat steam temperature at 1,005°F. Excess O_2 level, measured at the economizer gas outlet, was maintained at 2.6 percent. Turbine cycle was isolated by switching auxiliary steam extractions from turbine cycle to Unit 2 while testing was performed on Unit 1, and vice versa. Also, sootblowing was out of service during the test, blowdown was closed, and make-up was kept at zero. Condenser hotwell was toped off before the test to eliminate need for normal make-up. Emergency make-up was isolated. For baseline test, pressure differential in a scrubber was maintained at 6.5 “wg for Unit 1 and at 5.5” wg for Unit 2. Sootblowing was performed before and between the tests.

Coal samples for each test performed on Unit 1 were collected off mill feeders 11, 14, 16, and 17 using specially designed sampling probe (see Figure 16) that was inserted into a feeder through a newly installed sample port (see Figure 17) to collect sample of coal falling off the belt. For Unit 2, coal samples collected by the automatic as-received coal sampler (CS2) located in crusher building were used because Unit 2 feeders were not equipped with sampling ports.

Figure 16: Coal Sampling Probe

Figure 17: Feeder Sampling Port

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 by recording weight before and after the test and dividing it by elapsed time between readings. Samples were obtained from two downcomer cleanouts and blended (see Figure 18). The flow rate of mill rejects was determined by measuring level in the rejects tank before and after the test. Samples were collected in pans every 15 minutes between first and second hour of the test. Based on historic data, fly ash was assumed to be 60 percent of the total ash flow. Bottom ash flow was determined as a difference.

Bottom Ash = Coal Flow x Ash – (Fly Ash + Pulverizer Rejects + Economizer Ash)

Figure 18: Sampling of Economizer Ash from a Downcomer

Process data, except CEM data, were collected and recorded by plant data historian (PHD). CEM data were collected off the CEM computer. PHD also provides on-line process data to Online Performance Monitoring (OPM) workstation which performs on-line performance calculations and calculates gross turbine cycle heat rate, boiler efficiency, and net unit heat rate, amongst other parameters. On-line OPM calculations are performed using default values of coal composition and HHV, therefore on-line values are treated as preliminary. The preliminary values were used to determine periods of steady state operation (see Figure 19), which might be different from test duration, due to external disturbances to the boiler. After coal samples were analyzed by the plant coal lab, actual values were inputted to the OPM using "Scenario" option along steady state operating data to calculate actual steady state values of performance parameters.

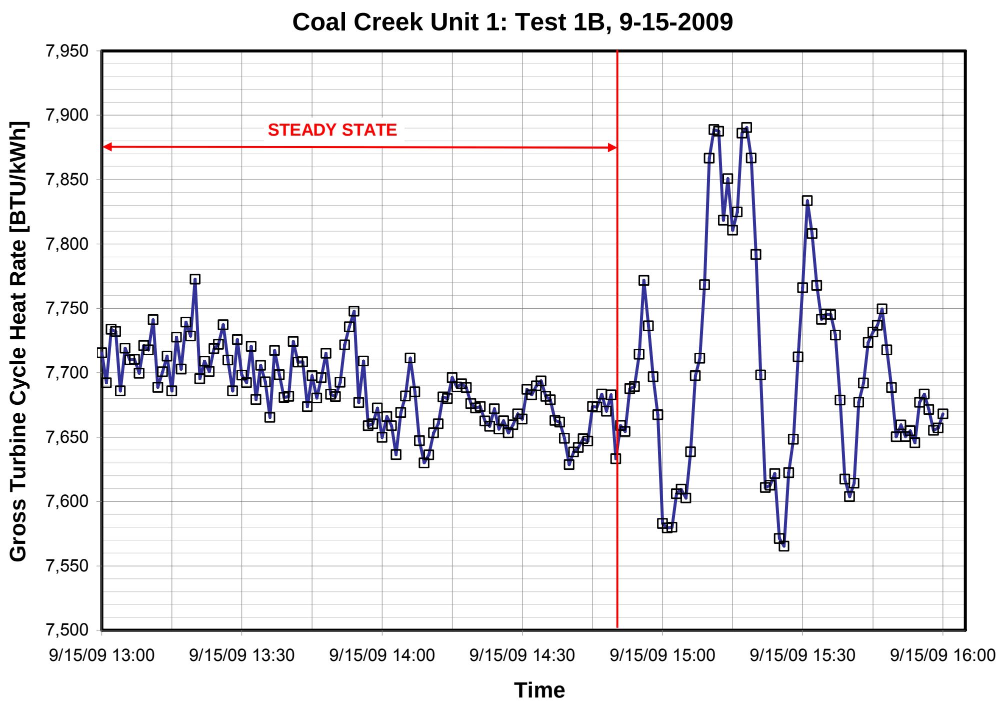

Figure 19: Period of Steady State Operation: Test 1B

A diagram of Coal Creek Unit 1 and sampling locations is presented in Figure 20. Gas sample points indicate locations where flue gas mercury (Hg) concentration was measured by wet impinger-based semi-continuous emissions monitors (sCEMs) or by sorbent traps. Total and elemental flue gas Hg concentration at the APH inlet, scrubber (FGD) inlet and outlet, and FGD bypass was measured by sCEMs. Schematic diagram of a sCEM is presented in Figure 21. At each sample location, a sample of the flue gas is extracted at a single point from the duct, drawn through an inertial gas separation (IGS) filter to remove particulate matter, and returned to the duct. A secondary sample stream is pulled across the filter and directed through the mercury analyzer at a rate of approximately 1 to 2 liters per minute, thus providing near real-time feedback during the test.

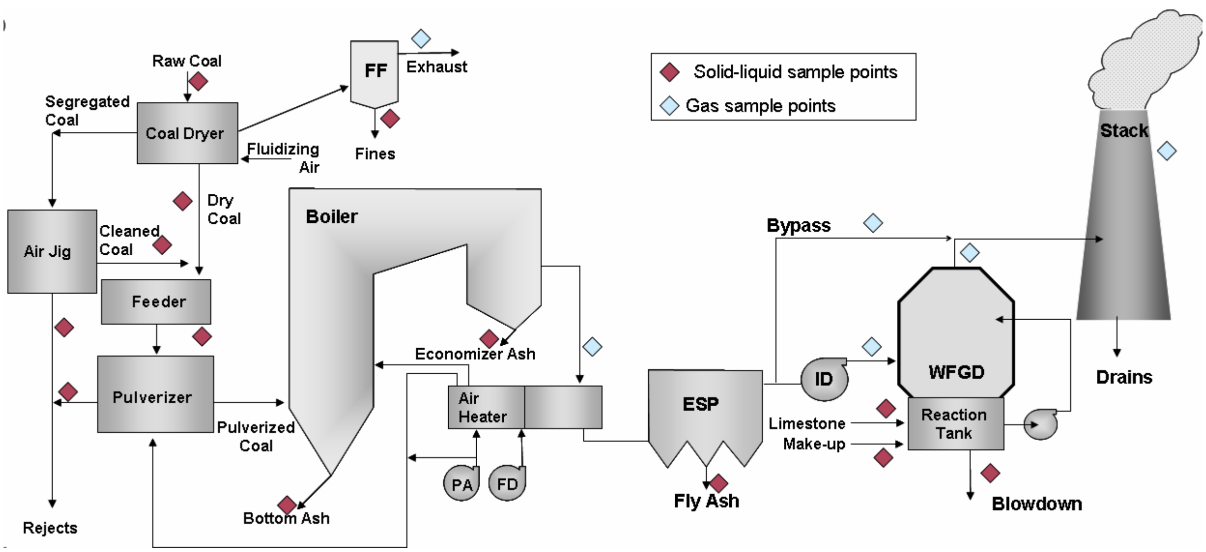

Figure 20: Diagram of Coal Creek Unit 1 and Sampling Locations

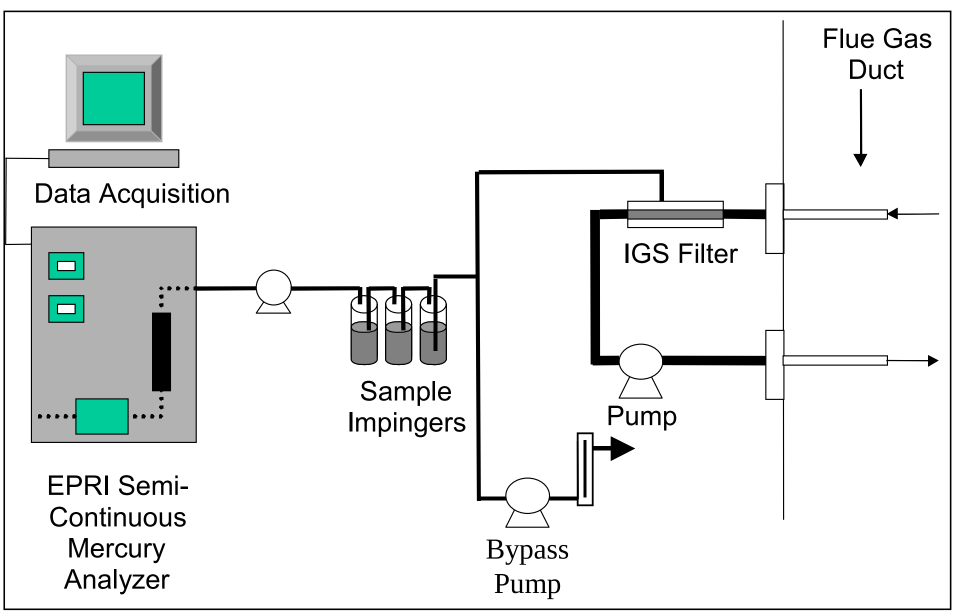

Figure 21: Semi-Continuous Mercury Analyzer

Sorbent traps were used to measure total Hg concentration at the FGD bypass, outlet and the stack. Liquid and solid samples were taken from the wet scrubber blowdown liquor and analyzed for SO_3^{2-}, Cl, Br, pH, and oxidation-reduction potential (ORP). No samples were taken from coal dryers and air jigs during the baseline tests because those were out of service.

6.1. Baseline Tests with Wet Coal

Nine tests were performed on Unit 1, and three tests on Unit 2 at Coal Creek in September 2009 do determine baseline unit performance and emission levels when firing wet lignite. Test start and end times are summarized in Table 5.

Unit performance parameters included gross power output, gross turbine cycle heat rate, boiler efficiency, auxiliary power use (PA, FD, and ID fan and mill power), net unit heat rate, coal feed, fuel heat input to the boiler and other parameters. Emissions measurements included NO_x, SO_2, Hg, CO_2, trace metals, and opacity at the stack, Hg speciation at the APH gas inlet, scrubber inlet and outlet, and scrubber bypass.

A multi-point gas extraction grid was used at Unit 1 to perform measurements of flue gas temperature, O_2, CO, and NO_x at the outlet of APHs 11 and 12. Grid measurements were compared to plant instrumentation. Plant instrumentation was used at Unit 2. Flue gas moisture content was measured at Unit 1. Data flow diagram of measured and calculated parameters is presented in Figure 22. Solid samples (coal and ash) collected during baseline test are summarized in Table 6 along with performed analyses.

The test schedule for flue gas Hg concentration measurements performed by the sCEMs and sorbent traps, and trace metal measurements performed by the EPA Method 29 in the stack is presented in Table 7. Coal Creek is equipped with a continuous Hg monitor (manufactured by Tekran) installed in the stack.

However, plant monitor did not pass quality control during the baseline test period, so continuous Hg measurements are not reported.

Table 5: Start and End Times for Baseline Tests with Wet Coal

UNIT 1		Test Start & End Times		Steady State Start & End Times	
Test	Date	Start	End	Start	End
1A	9/15/2009	8:00	11:00	**10:00**	**11:00**
1B	9/15/2009	13:00	16:00	**13:00**	**14:45**
2A	9/16/2009	8:00	11:00	**8:00**	**11:00**
2B	9/16/2009	13:00	17:00	**13:00**	**16:00**
3A	9/17/2009	8:00	11:05	**8:00**	**11:00**
3B	9/17/2009	12:00	14:30	**12:00**	**14:30**
3C	9/17/2009	15:30	18:00	**15:30**	**17:30**
4A	9/18/2009	8:30	11:30	**8:00**	**11:00**
4B	9/19/2009	12:30	15:45	**12:45**	**15:30**
UNIT 2		**Test Start & End Times**		**Steady State Start & End Times**	
Test	Date	Start	End	Start	End
5A	9/21/2009	8:00	11:00	**8:00**	**11:00**
5B	9/21/2009	13:00	16:00	**13:05**	**16:00**
6A	9/22/2009	8:15	11:15	**8:45**	**10:45**

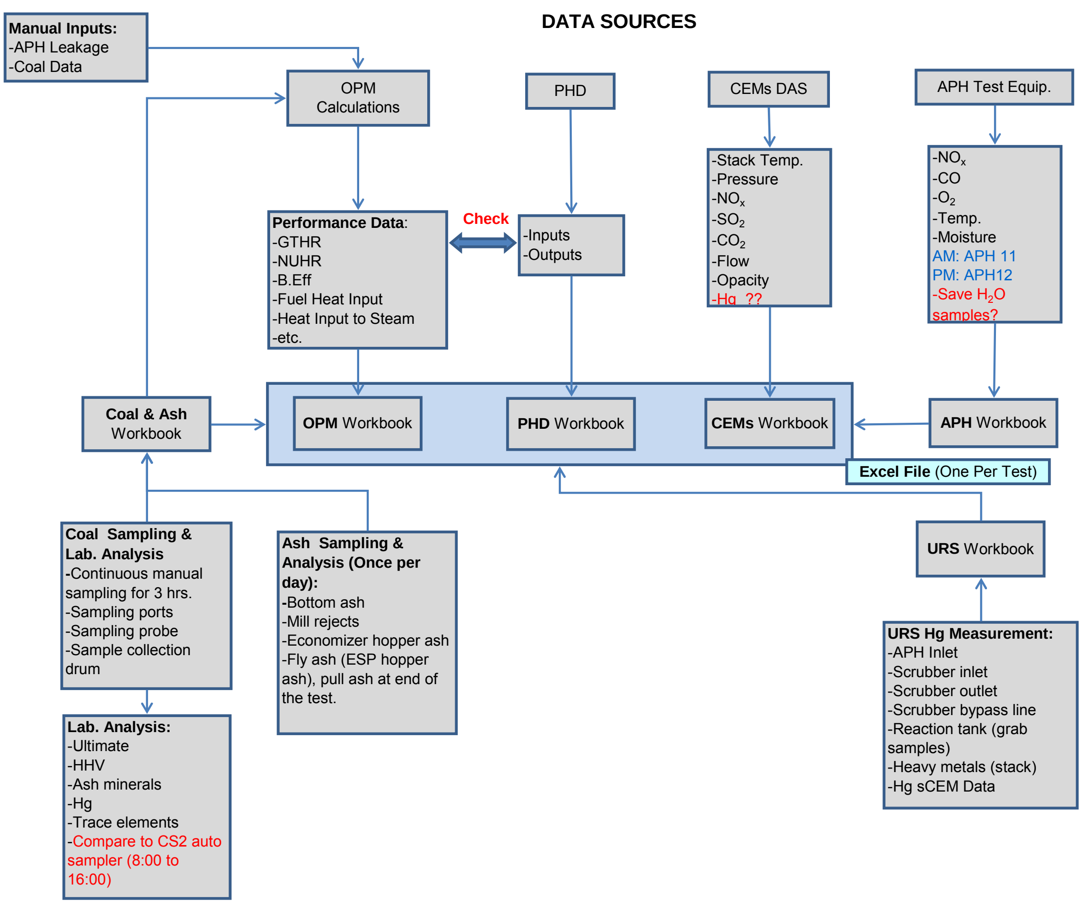

Figure 22: Data Flow Diagram of Measured and Calculated Parameters

Table 6: Collected Solid Samples and Performed Analyses

DATE	Coal Feeders	Mill Rejects	Economizer Ash	Bottom Ash	Fly Ash
9/15/2009	1A 1B	1A 1B	1A 1B	1A	1
9/16/2009	2A 2B	1	2AB	2 HOPPER 13	1
9/17/2009	3A 3B 3C	3A 3B 3C	3A 3B 3C	3 HOPPER 11 3 HOPPER13 3 HOPPER15	1
9/18/2009	4A 4B	4A 4B	4A 4B	4 HOP 11,13,15	1
9/21/2009	5A 5B CS2	5A 5B	5A 5B	5 HOPPER 21	1
9/22/2009	6A CS2			6 HOPPER25 6 HOPPER23 6 HOPPER21	1
Sample Analysis	Proximate and ultimate analyses, ash minerals, Hg	Short proximate analysis, LOI, ash minerals, Hg	LOI, ash minerals, Hg	LOI, ash minerals, Hg	LOI, ash minerals, Hg
	Trace minerals	Trace minerals	Trace minerals	Trace minerals	Trace minerals
		Bulk Density	Bulk Density	Bulk Density	Bulk Density

Table 7: Mercury and Trace Metal Measurement Times during Baseline Test

Date	9/15/2009	9/16/2009	9/17/2009	9/18/2009
SCEM 1: APH inlet	16:27-18:32	All day	All day	until 7:51
SCEM 2: FGD inlet, FGD outlet, FGD bypass	16:39-17:45	All day	All day	until 15:49
Sorbent Trap: FGD bypass		Run 1: 10:02-11:02 Run 2: 13:28-14:28 Run 3: 15:17-16:17		
Sorbent Trap: FGD outlet		Run 1: 10:00-11:00 Run 2: 13:28-14:28 Run 3: 15:17-16:17		
Sorbent Trap: Stack		Run 1: 10:00-11:00 Run 2: 13:29-14:29 Run 3: 15:18-16:18		
Method 29: Stack			Run 1: 8:35-11:02 Run 2: 12:00-14:30 Run 3: 15:30-17:56	

6.2. Preliminary Tests with Dried Coal

Five tests (one pretest and four tests) were performed on Unit 1 in March and early April 2010 to determine unit performance and emission levels when firing dried lignite. Test start and end times are summarized in Table 8.

Table 8: Start and End Times for Test with Dried Coal

UNIT 1		Test Start & End Times		Steady State Start & End Times		
Test	Date	Start	End	Start	End	Filename
1A	3/11/2010	13:00	15:00			Test 1A--3-11-10-OPM.xls
2A	3/31/2010	9:00	12:00			Test 2A -3-31-10-OPM.xls
2B	3/31/2010	13:00	16:00			Test 2B -3-31-10-OPM.xls
3A	4/1/2010	9:00	12:00			Test 3A -4-1-10-OPM.xls
3B	4//1/2010	13:00	16:00			Test 3B -4-1-10-OPM.xls

The unit was kept at steady state operating conditions during the test; steam parameters were kept at same values as during baseline tests with wet coal. However, since Unit 2 was in outage during Tests 2A to 3B, Unit 1 steam turbine cycle could not be isolated and auxiliary steam extractions were provided by Unit 1. The auxiliary steam extractions reduced gross power output by at least 13 MW (approximately 2 percent) and need to be accounted for when calculating turbine cycle heat rate. Test 1A was performed with seven mills in service (mill 11 was out of service), while Tests 2A to 3B were performed with six mills in service (mills 17 and 18 were out of service). Pressure differential in a scrubber was maintained at 7.5" wg during Test 1A and at 8.5 "wg during Tests 2A to 3B. Excess O_2 level at the economizer outlet was kept at 2.6 percent. A 15 percent bias was implemented on hot corners in the boiler. Boiler overfire air (OFA) dampers were 90 percent open. Heat input to the dryers was set to 80 percent (x = 0.80). All eight coal dryers were in operation during Test 1A. All four Unit 1 dryers were in operation during Tests 2A to 3B.

Performance parameters included gross power output, gross turbine cycle heat rate, boiler efficiency, auxiliary power use (PA, FD, and ID fan and mill power), net unit heat rate, coal feed to the dryers, fuel heat input to the boiler, flow rates of primary and secondary air, and air and flue gas temperatures at the

APH inlet and outlet. Additional parameters included heat input to the coal dryers, dryer plenum, bed and freeboard temperatures, and flow rate of fluidizing air. Emissions measurements included NO_x, SO_2, Hg, CO_2, trace metals, and opacity at the stack, CO concentration at dryer baghouse (dust collector), Hg speciation at the APH gas inlet, scrubber inlet and outlet, and scrubber bypass. The test schedule for Hg measurements is presented in Table 9.

Table 9: Mercury Measurement Times during Tests with Dried Coal

Date	3/11/2010	3/31/2010	4/1/2010
SCEM 1: APH Inlet	10:30 - 17:00	All Day	Until 16:00
SCEM 2: FGD Inlet, FGD Outlet, FGD Bypass	10:30 - 17:00	All Day	Until 16:00
Sorbent Trap: FGD Bypass	NA	Run 1: 9:12 - 11:42 Run 2: 13:04 - 15:32 Run 3: 16:00 - 17:00	Run 1: 9:00 - 11:30 Run 2: 13:00 - 15:30
Sorbent Trap: FGD Outlet	NA	Run 1: 9:12 - 11:42 Run 2: 13:04 - 15:34 Run 3: 16:00 - 17:00	Run 1: 9:00 - 11:30 Run 2: 13:00 - 15:30
Plant Hg Monitor: Stack	All Day	All Day	All Day

Plant instrumentation was used to measure temperature of flue gas leaving APHs 11 and 12. Instead of performing grid measurements at the APH outlet, excess O_2 level measured by a probe located at the scrubber inlet was used to calculate APH leakage. This is because analysis of the baseline data has shown that the average excess O_2 level measured at the APH gas outlet by a multi-point gas extraction grid was very close to the excess O_2 level measured at the scrubber inlet. Data flow of measured and calculated parameters is similar to the one presented in Figure 22, except multi-point gas extraction grids at the outlets of APHs 11 and 12 were not used.

Solid samples (coal and ash) were collected from same locations as for the baseline tests (see Table 6). During 2010 testing, coal samples were taken from feeders 11, 12, 14 and 16. In addition, coal samples were taken before and after the air jig to characterize segregation stream and quantify air jig effectiveness. Manual coal samples of the product stream were taken from conveyer 266 (air jig inlet) and 269 (air jig outlet). Automatic coal sampler (CS2) was used to obtain coal samples from conveyors 961 and 962.

Total and elemental flue gas Hg concentration was measured by sCEMs at the APH inlet, FGD inlet, outlet, and bypass. Plant continuous Hg monitor was used to measure total and elemental mercury in the stack. Total flue gas mercury concentration was measured by sorbent traps at the FGD outlet and bypass.

7. UNIT PERFORMANCE

7.1. Boiler and Plant Operating Parameters

As discussed in Section 6 of the report, the unit was kept at steady state operating conditions during tests performed with wet (September 2009) and dried coal (March/April 2010). Boiler excess O_2 level was maintained at approximately 2.6 percent (see Figure 23). Average value of burner tilt angle for all eight boiler corners, presented in Figure 24, shows that tilt angle for wet coal was maintained at approximately 19 degrees, while for dried coal burner tilt angle was lower, approximately 15 degrees. Main steam temperature (T_{MST}) values for tests performed with wet and dried coal are presented in Figure 25, while values of hot reheat steam temperature (T_{HRHT}) are given in Figure 26. The average value of T_{MST} with dried coal of 986°F was approximately 5°F lower compared to the average value of T_{MST} with wet coal. Part of this difference is due to lower burner tilt angle. The average values of T_{HRHT} for tests performed with wet and dried coal were approximately the same.

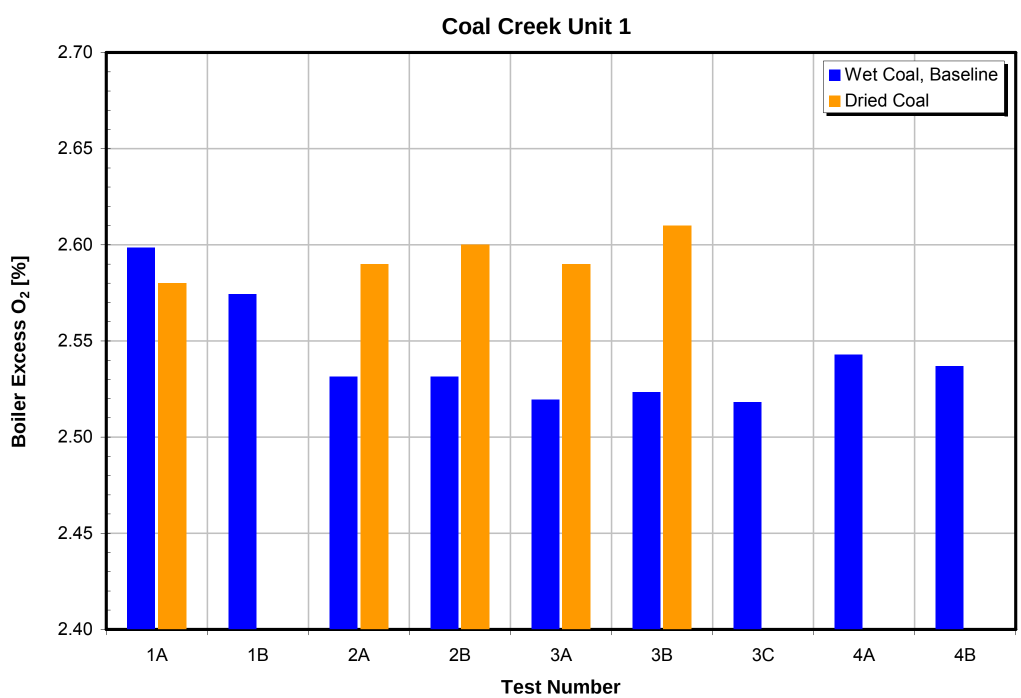

Figure 23: Boiler Excess O_2 Level

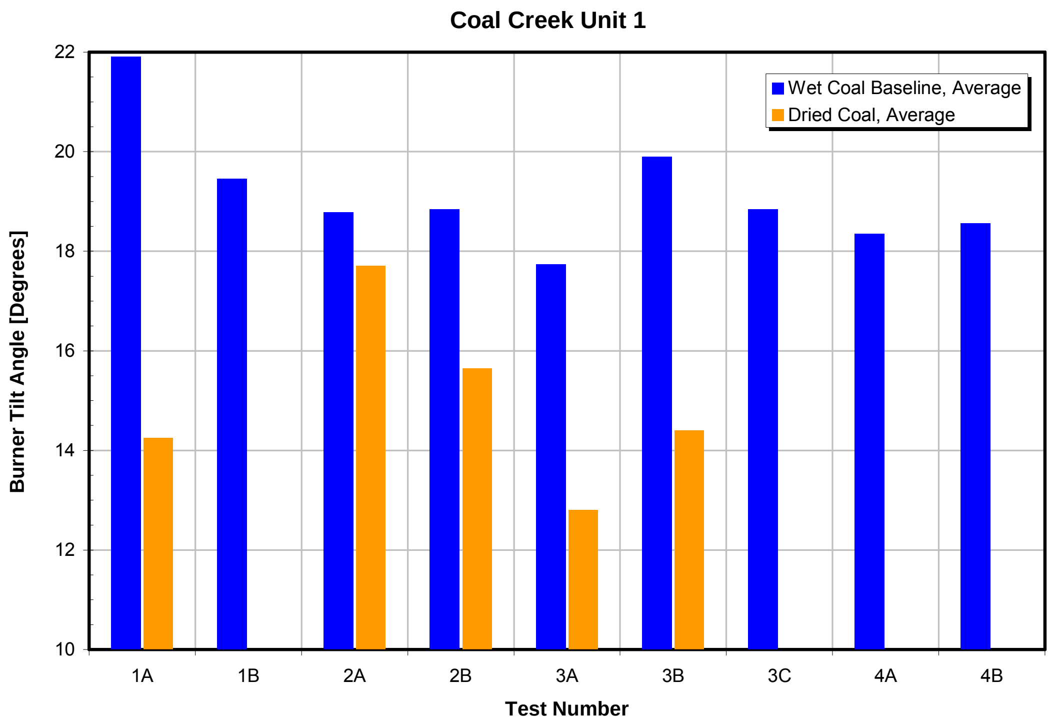

Figure 24: Burner Tilt Angle

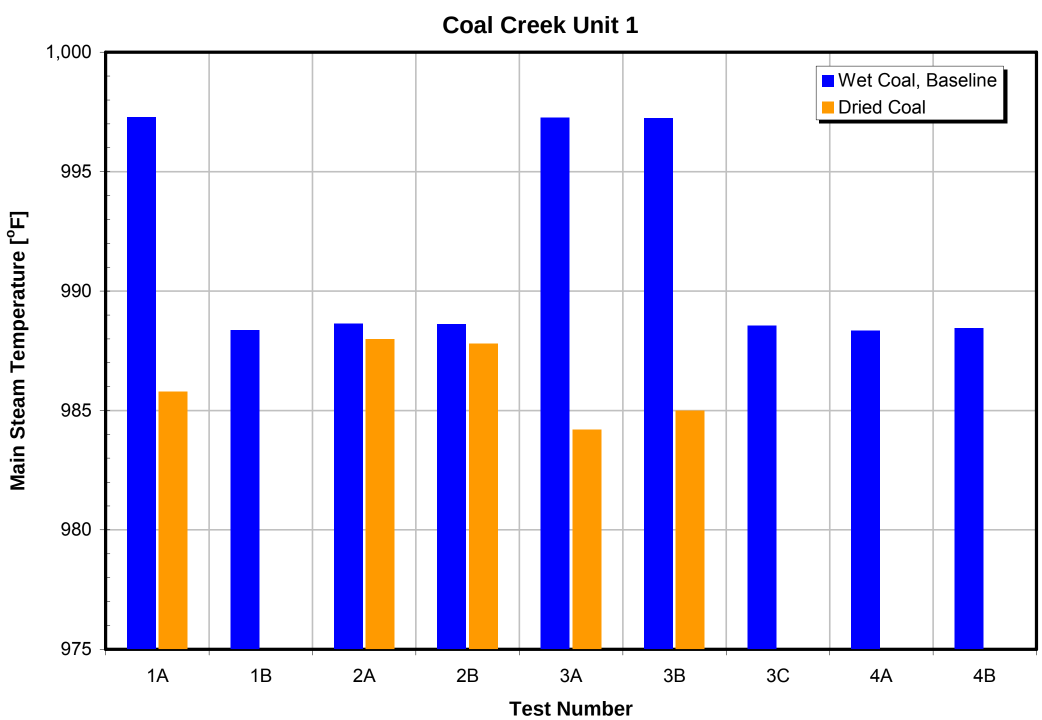

Figure 25: Main Steam Temperature

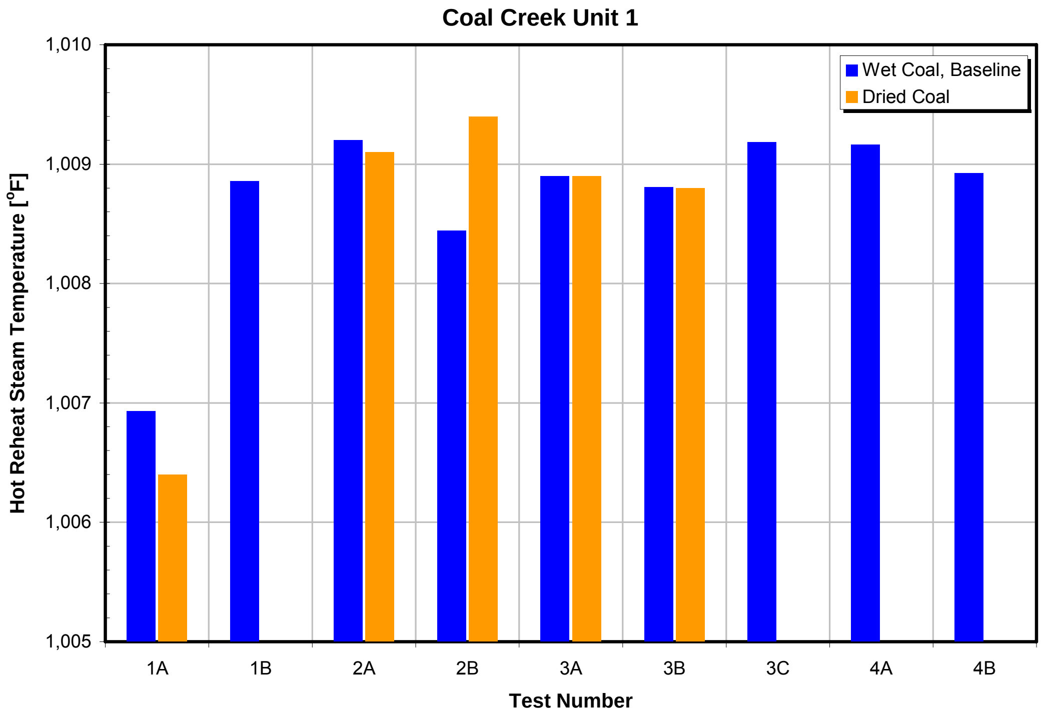

Figure 26: Hot Reheat Steam Temperature

Gross unit power output (P_G) is presented in Figure 27. The average value of P_G for tests conducted with wet and dried coal was 600 and 605 MW, respectively. Values of gross power output for preliminary tests with dried coal, presented in Figure 27, were corrected for auxiliary steam extractions. Higher P_G obtained with dried coal is due to lower condenser pressure (lower cooling water temperature), lower T_{MST}, and higher main steam flow (2 percent higher). The data on total auxiliary power use (P_{AUX}), presented in Figure 28, show that P_{AUX} for tests performed with wet and dried coal was approximately the same, 41.2 and 41.5 MW, respectively. For preliminary tests with dried coal, P_{AUX} includes crusher power and power to run conveyer systems for feed, product, and segregation streams, baghouse exhaust fan power, in addition to other plant loads and loads normally carried by Unit 2. Contributions to P_{AUX} due fan and mill power are discussed in subsections 7.2 and 7.3.

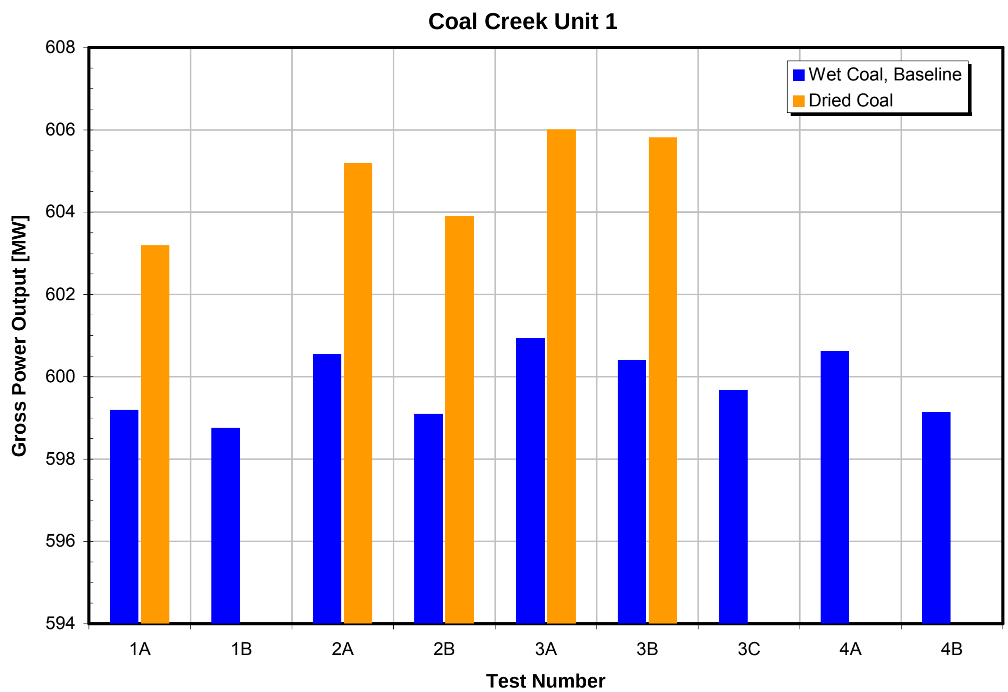

Figure 27: Gross Power Output

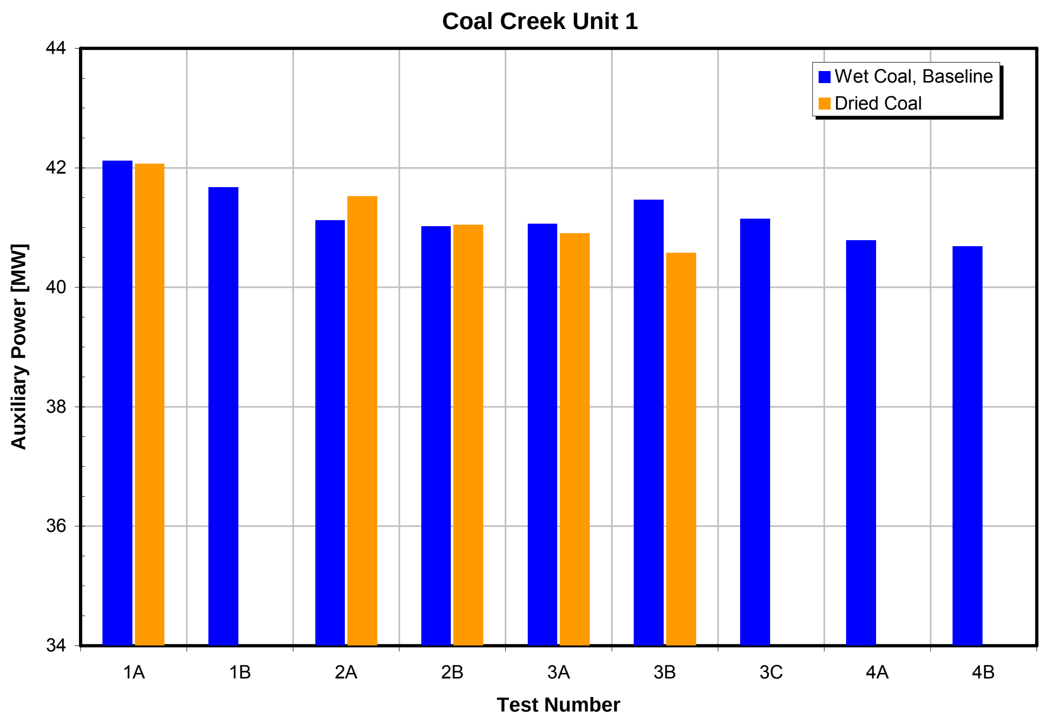

Figure 28: Total Auxiliary Power

7.2. Coal Flow and Mill Power

As a portion of coal moisture is evaporated by thermal drying, HHV increases and 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, so less coal is needed for same gross power output. Total coal feed to the boiler, measured by coal feeders, is presented in Figure 29 for tests performed with wet and dried coals. Reduction in coal feed relative to the wet coal baseline, given in Figure 30, shows that coal feed for Tests 2A to 3B performed in March/April 2010 was reduced by more than 10 percent.

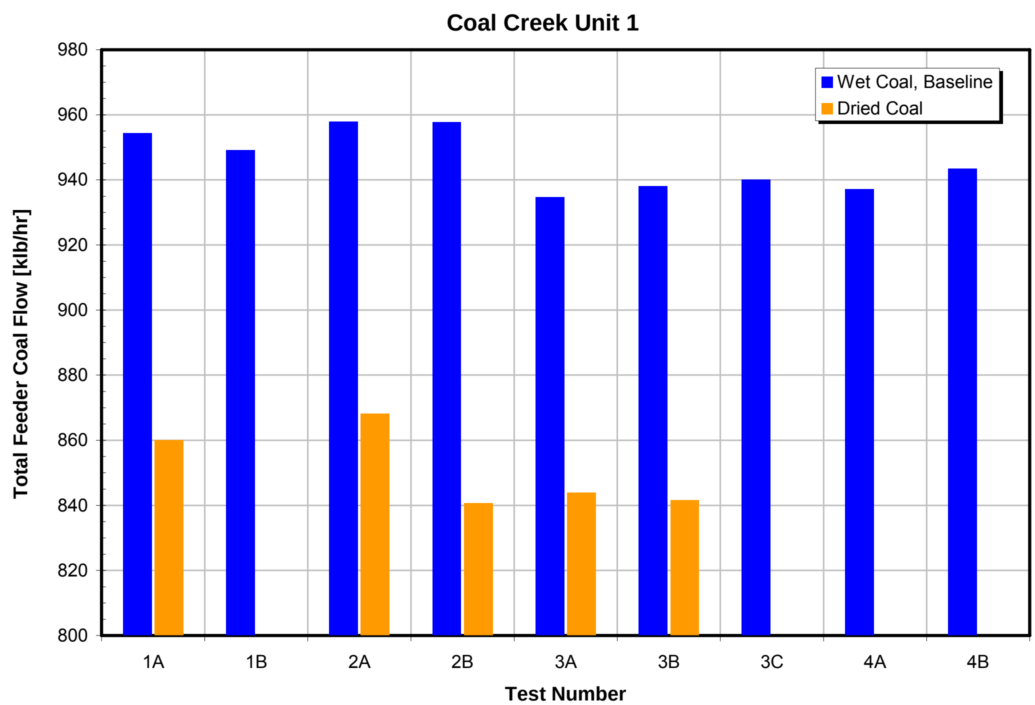

Figure 29: Coal Feed Rate

Data on flow rate of primary air (M_{PA}) to the mills, presented in Figures 31 and 32, show that for tests with dried coal M_{PA} was, according to expectations, considerably reduced compared to operation with wet coal. The average reduction (see Figure 33) was in a 35 to 36 percent range. As a result, for dried coal, primary air to coal ratio decreased from baseline value of 3.3 to 2.4 lb primary air/lb coal.

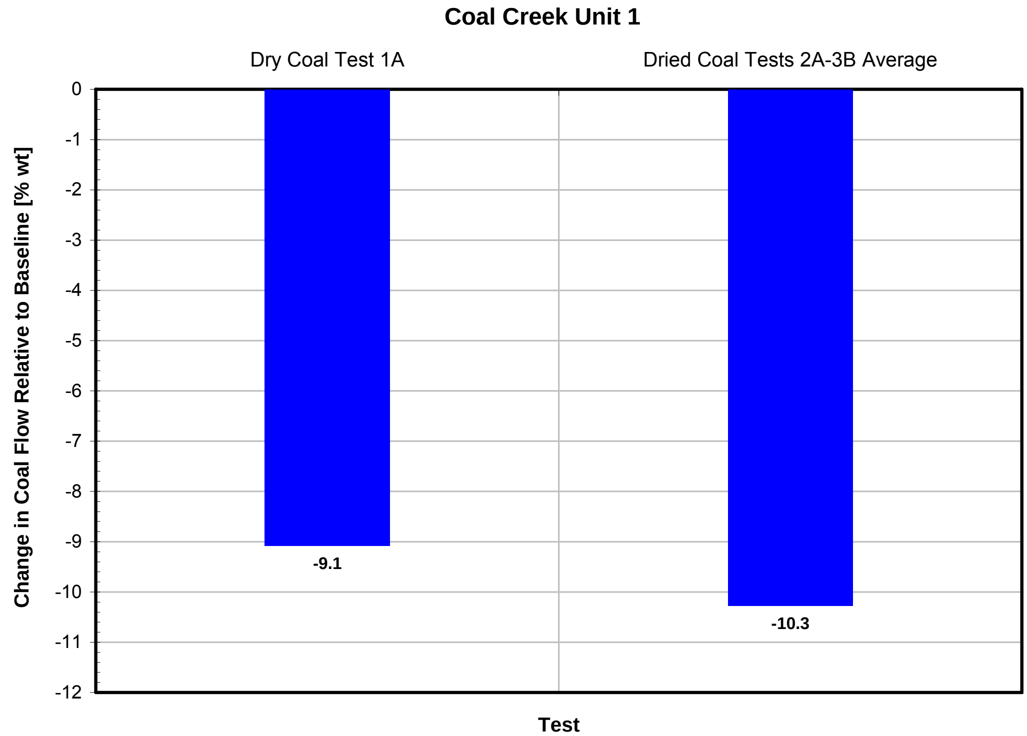

Figure 30: Change in Coal Feed Rate Relative to Wet Coal Baseline

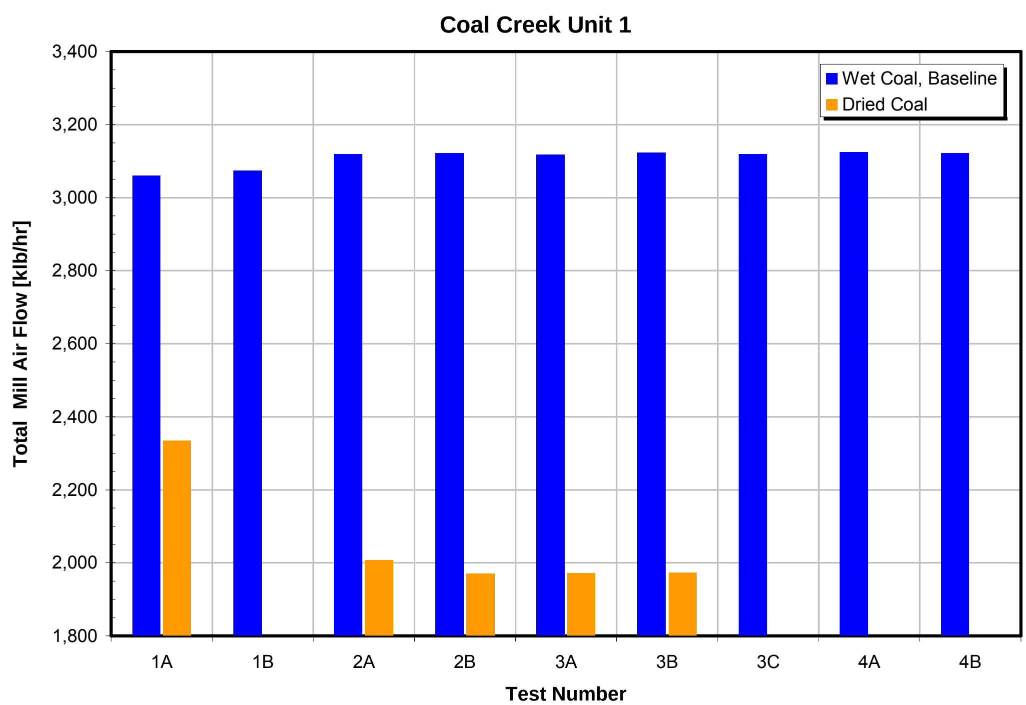

Figure 31: Total Flow Rate of Primary Air to Mills: Individual Tests

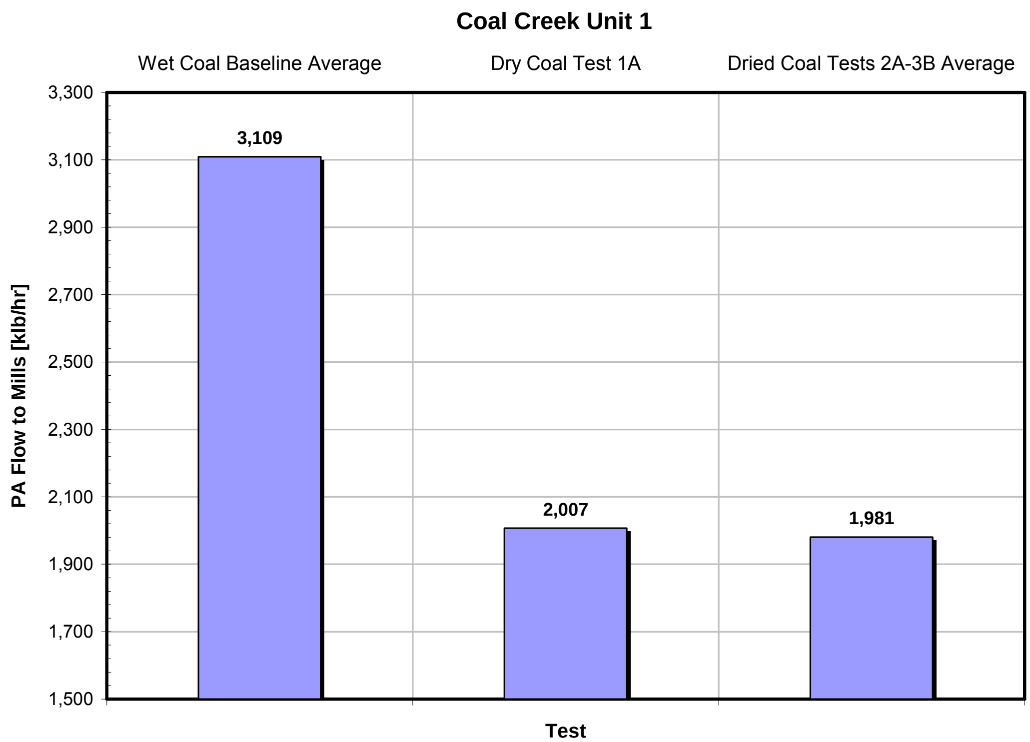

Figure 32: Total Flow Rate of Primary Air to Mills: Test Averages

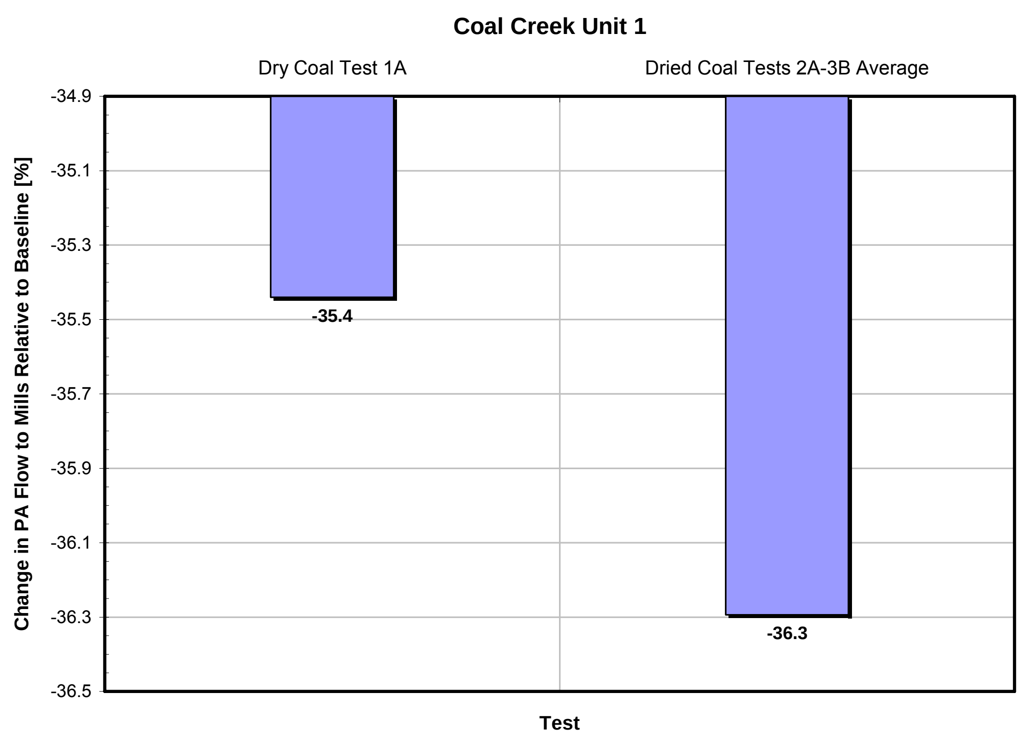

Figure 33: Change in Primary Air Flow Relative to Wet Coal Baseline

Temperature of primary air-coal mixture measured at mill outlet (mill temperature, T_{mill}) for tests with wet and dried coal is compared in Figure 34. The average value of T_{mill} during tests performed with wet coal of 159°F was approximately 4°F higher compared to the average value of this parameter measured during tests with dried coal, most likely due to difference in cold PA flow.

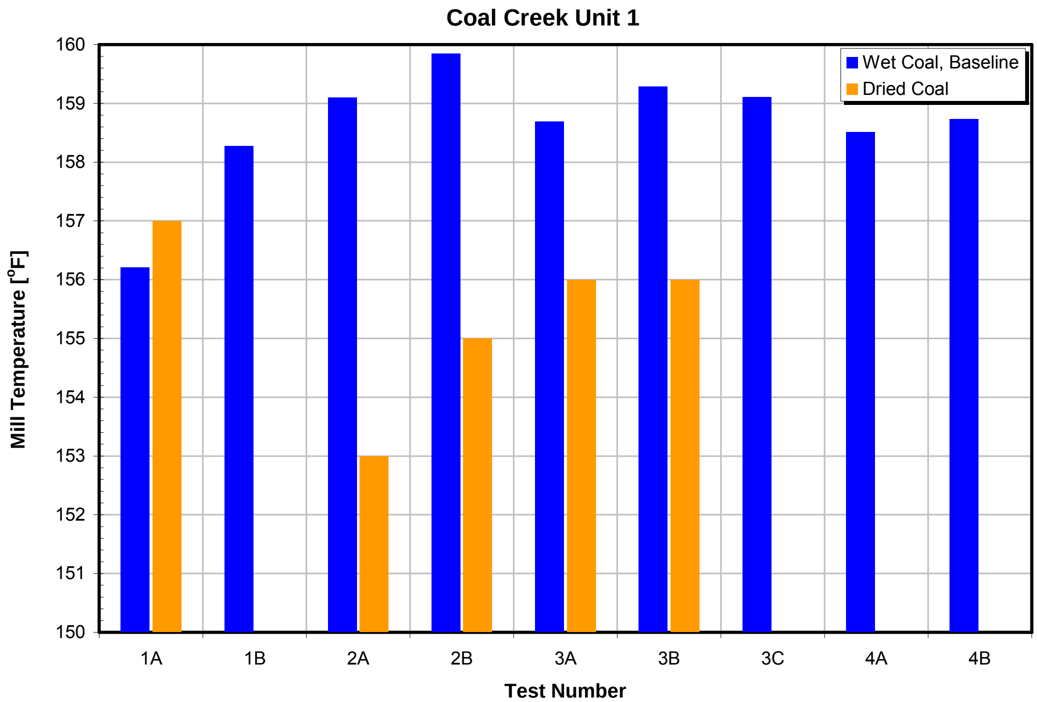

Figure 34: Average Temperature of Primary-Coal Mixture Leaving Mills

Values of total mill power measured during tests performed with wet and dried coal, compared in Figure 35, show that with dried coal mill power requirements were lower, as expected. As shown in Figure 36, reduction in mill power relative to the wet coal baseline is in a 13 to 14 percent range. Part of the mill power reduction is due to lower coal feed to the boiler; the other part is due to improved grindability of dried coal. Also, with dried coal full load was maintained with six mills in service, compared to eight mills which are needed for wet coal. This provides for maintenance flexibility and further reduces NO_x emissions when top mill is not in operation.

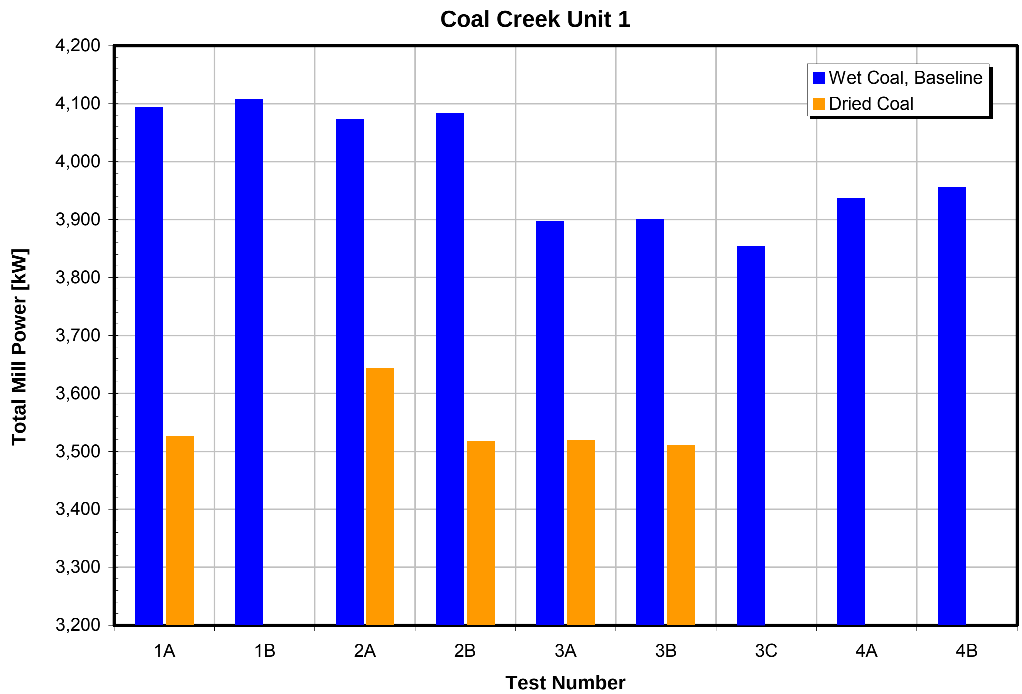

Figure 35: Total Mill Power

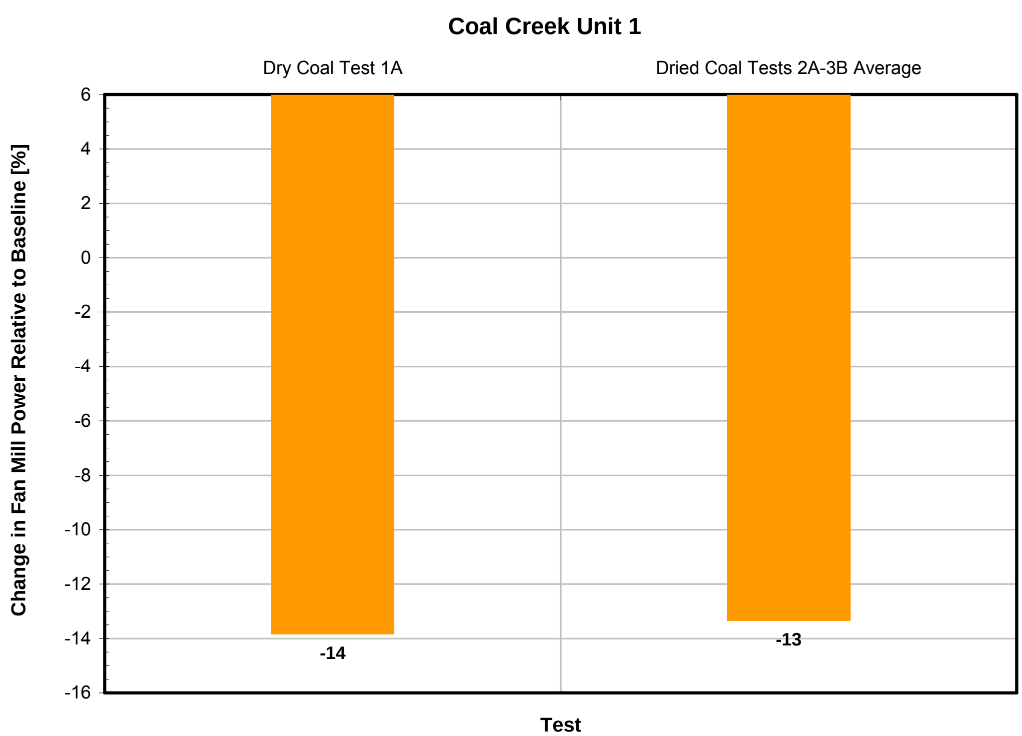

Figure 36: Change in Total Mill Power

7.3. Flow Rates of Air and Flue Gas, and Fan Power

Values of total air flow (primary and secondary air) for tests conducted with wet and dried coal are compared in Figure 37. Average values of total air flow for both test series are approximately the same 5,323 and 3,251 klb/hr, respectively.

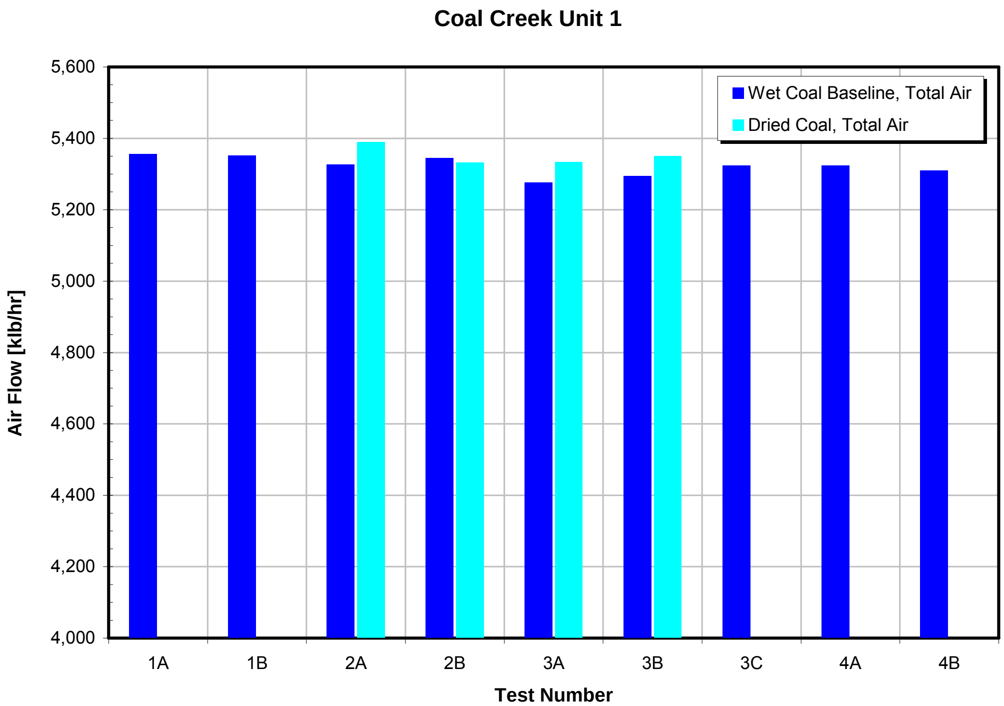

Figure 37: Total Air Flow

Although total air flow remained constant, split between primary air (PA) and secondary air (SA) flows changed from 48/52 percent to 33/67 percent, for wet and dried coal, respectively as presented in Figures 38 and 39. This change in PA/SA split is due to reduction in PA flow with dried coal (see Figures 31 to 33). With constant total air flow, as PA flow is reduced, more air is available for combustion, i.e., as a secondary air. Higher SA flow results in higher opening of the SA dampers and more stable combustion. Also, more air is available for combustion staging for NO_x control, either using OFAs (Unit 1) or SOFAs (Unit 2). Lower PA flow also results in lower NO_x.

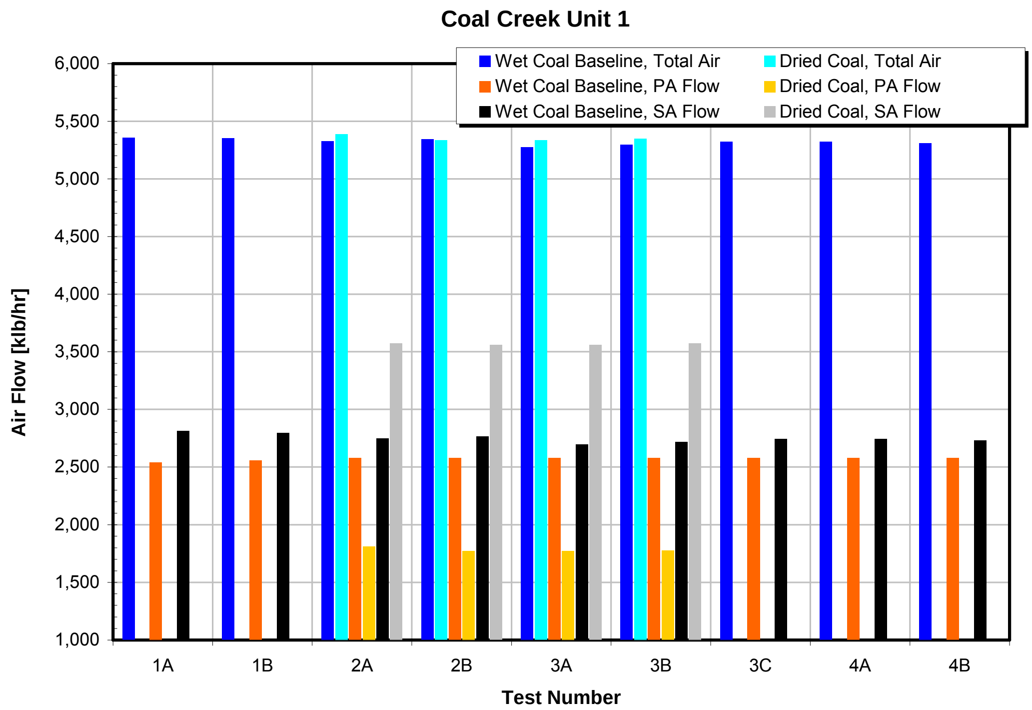

Figure 38: Primary and Secondary Air Flow for Wet and Dried Coal

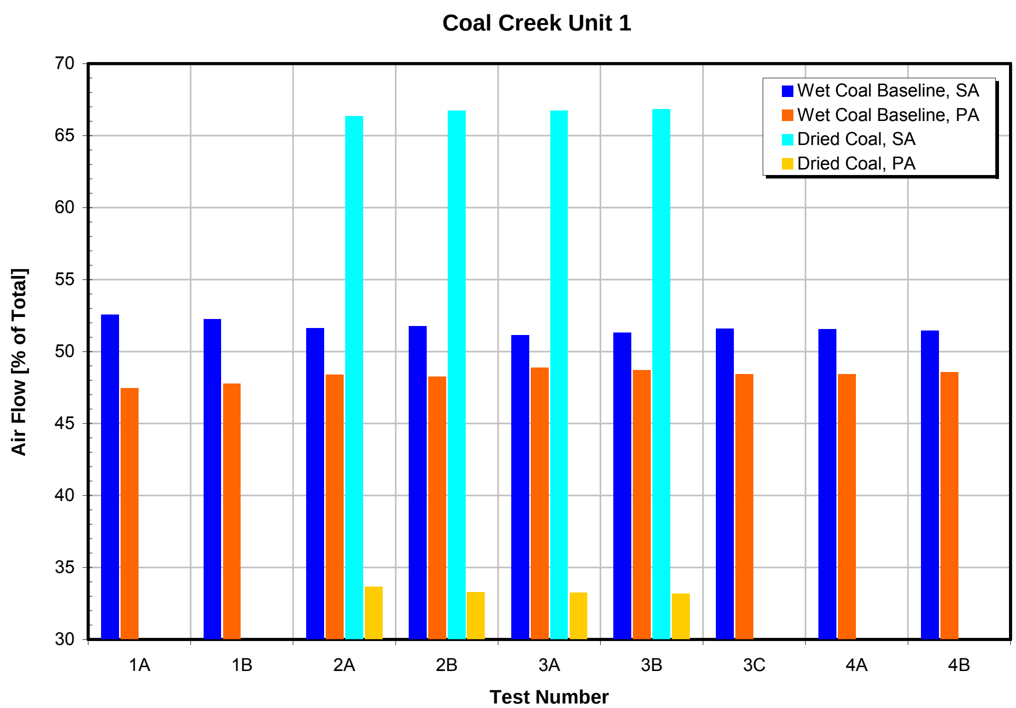

Figure 39: Primary and Secondary Air Flow as Percentage of Total Air for Wet and Dried Coal

As a portion of coal moisture is removed by thermal drying and unit efficiency is improved, the flow rate of flue gas is reduced. Values of flue gas flow rate measured by plant CEM during tests conducted with wet and dried coal are compared in Figure 40. With dried coal, flow rate of flue gas, measured by the plant CEM, was lower by 2.9 to 3.6 percent, compared to wet coal (see Figure 41).

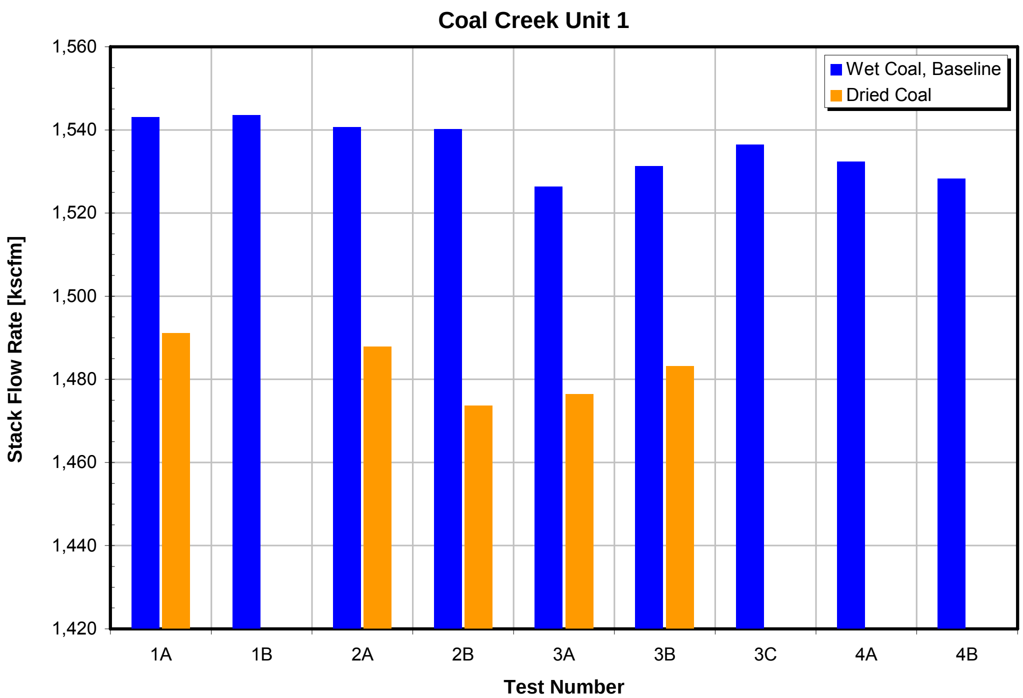

Figure 40: Flow Rate of Flue Gas Measured by Plant CEM

Values of forced draft (FD) fan power measured during tests performed with wet and dried coal are presented in Figure 42. Results for Tests 2A to 3B show that with dried coal FD fan power was higher (2,167 kW) compared to operation with wet coal (1,773 kW). This 394 kW or 22 percent increase in FD fan power (see Figure 47) is due to change in PA/SA flow split which results in higher flow rate of secondary (combustion) air through the FD fan.

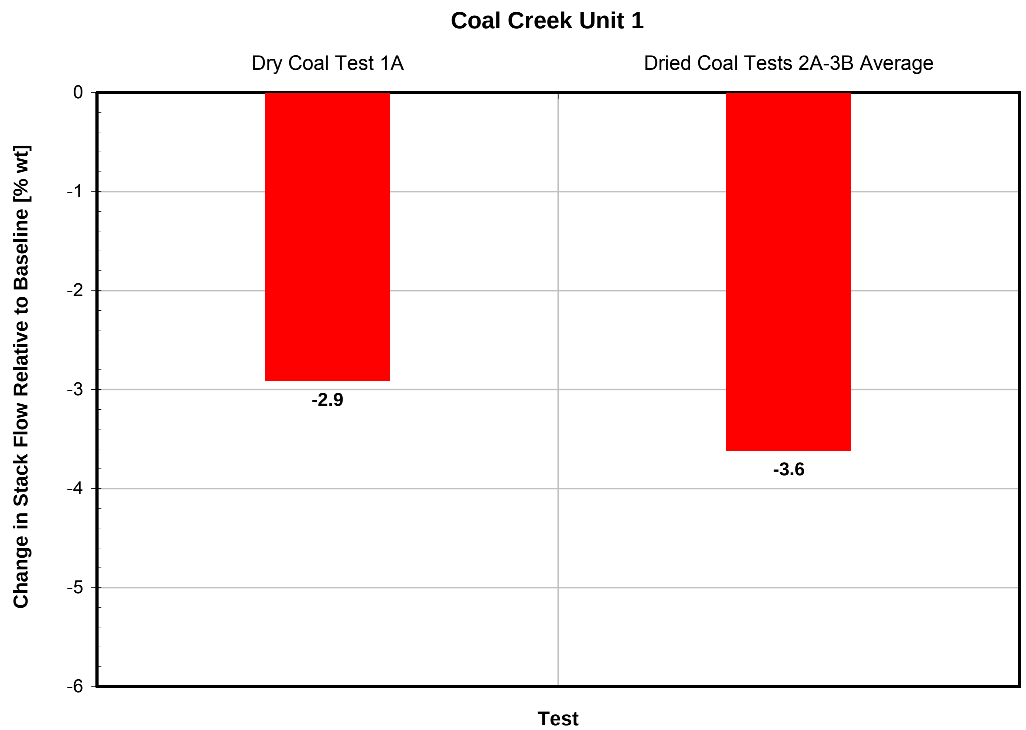

Figure 41: Change in Flue Gas Flow Rate Measured by Plant CEM

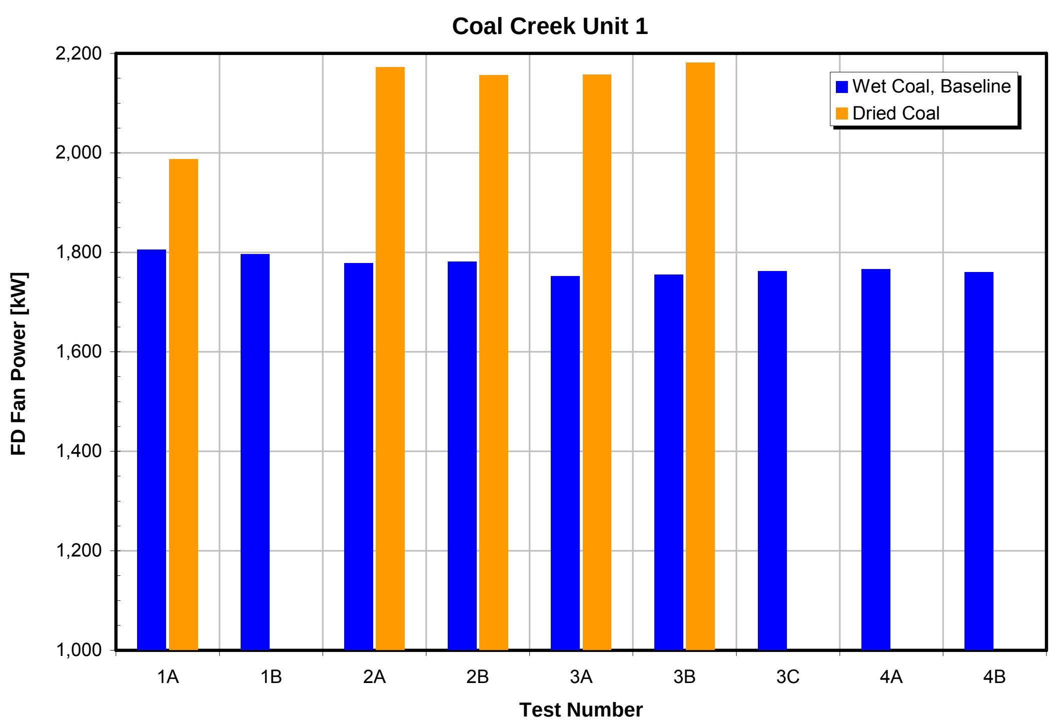

Figure 42: FD Fan Power

PA fan power measured during tests conducted with wet and dried coal is presented in Figure 43. Results for Tests 2A to 3B show that with dried coal PA fan power was higher (8,272 kW) compared to operation with wet coal (6,818 kW). This 1,454 kW or 21 percent increase in PA fan power (see Figure 44) is due to fluidizing air (1,440 klb/hr design value) which is supplied to the coal dryers by the PA fan, thus increasing total flow through the fan. Accounting for decrease in PA flow to the mills and the fact that actual fluidizing air flow was higher than design (approximately 1,600 klb/hr), total increase in cold PA flow is approximately 500 klb/hr or 15 to 18 percent relative to the wet coal baseline, (design value is 10 percent) assuming no change in APH air leakage patterns. Despite higher cold PA flow through the fan, the increase in PA fan power was not expected because with dried coal PA fan discharge pressure is considerably lower (approximately 40 “wg) compared to wet coal (approximately 50 “wg). Causes of higher PA fan power with dried coal, compared to wet coal baseline are under investigation.

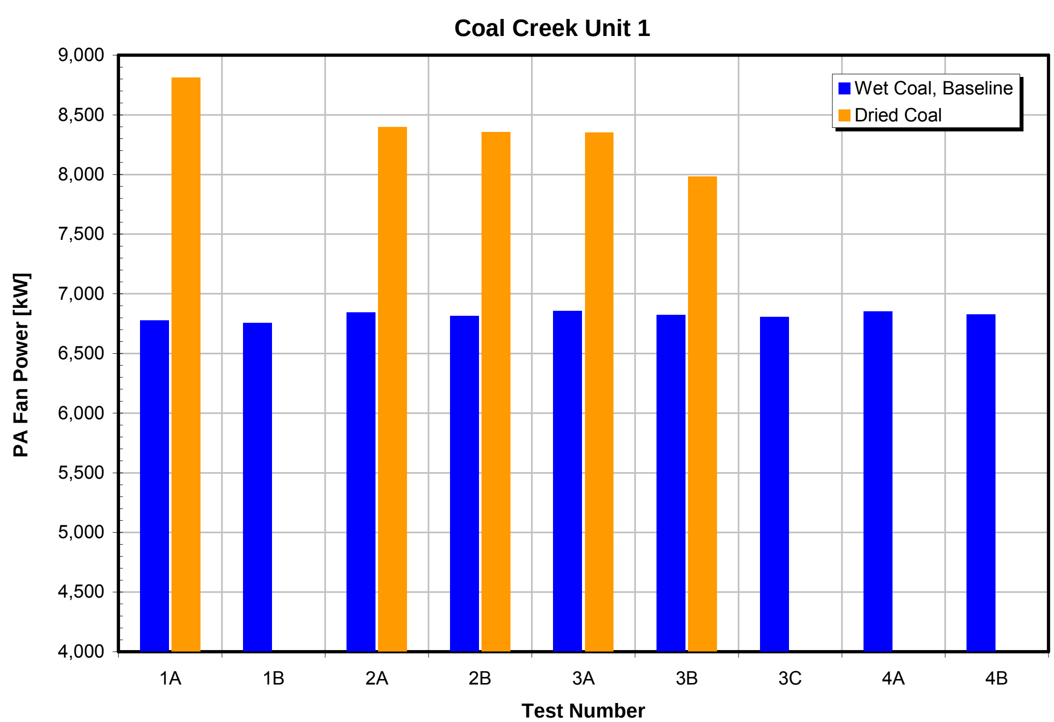

Figure 43: PA Fan Power

Induced draft (ID) fan power is presented in Figure 44. Due to decrease in flow rate of flue gas (see Figure 40) and reduction in APH gas-side pressure drop for operation with dried coal, ID fan power decreased from 8,767 kW to 7,685 kW (approximately 12.3 percent), despite increase in scrubber pressure drop by 2 "wg (from 6.5 to 8.5 "wg). It has to be noted that prior to DryFining^{TM} retrofit, ID fans were retrofitted with variable frequency drives (VFDs) which reduced ID fan power requirements by 3,000 kW or 26 percent compared to constant speed drives.

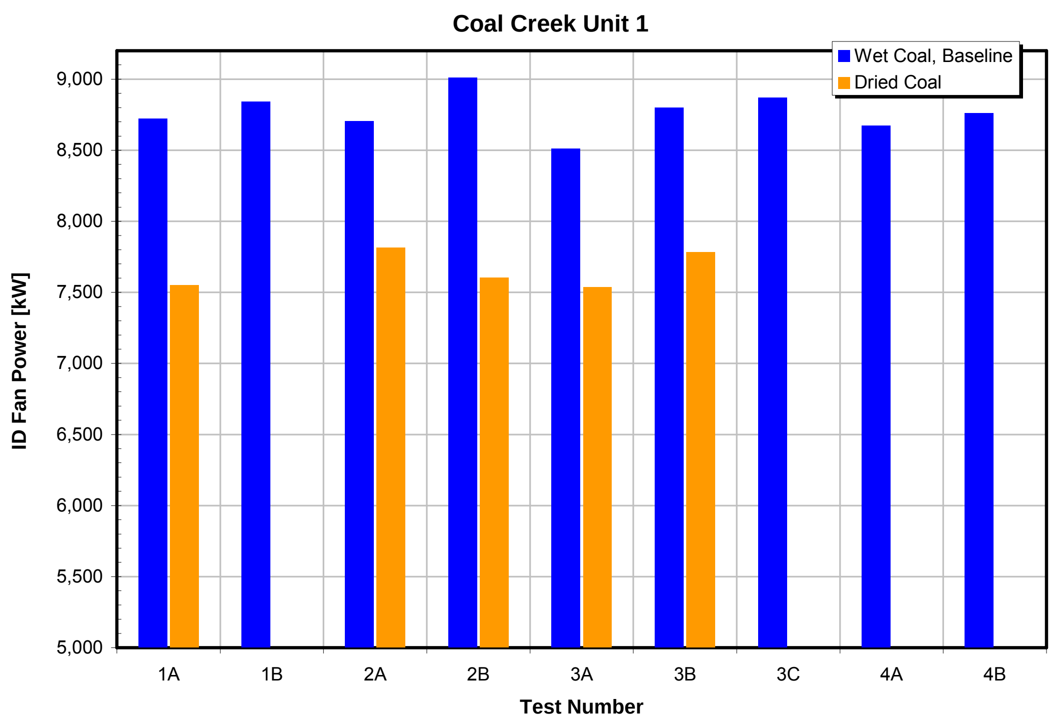

Figure 44: ID Fan Power

Total fan power, including FD, PA and ID fans, is presented in Figure 45. Due to increase in FD and PA fan power, the total fan power requirement for Tests 2A to 3B performed with dried coal was approximately 18,124 kW, which is approximately 4.4 percent higher, compared to the wet coal baseline (see Figure 47). On the other hand, total fan power for wet coal baseline tests was 15 percent lower, compared to operation with constant speed ID fan drives.

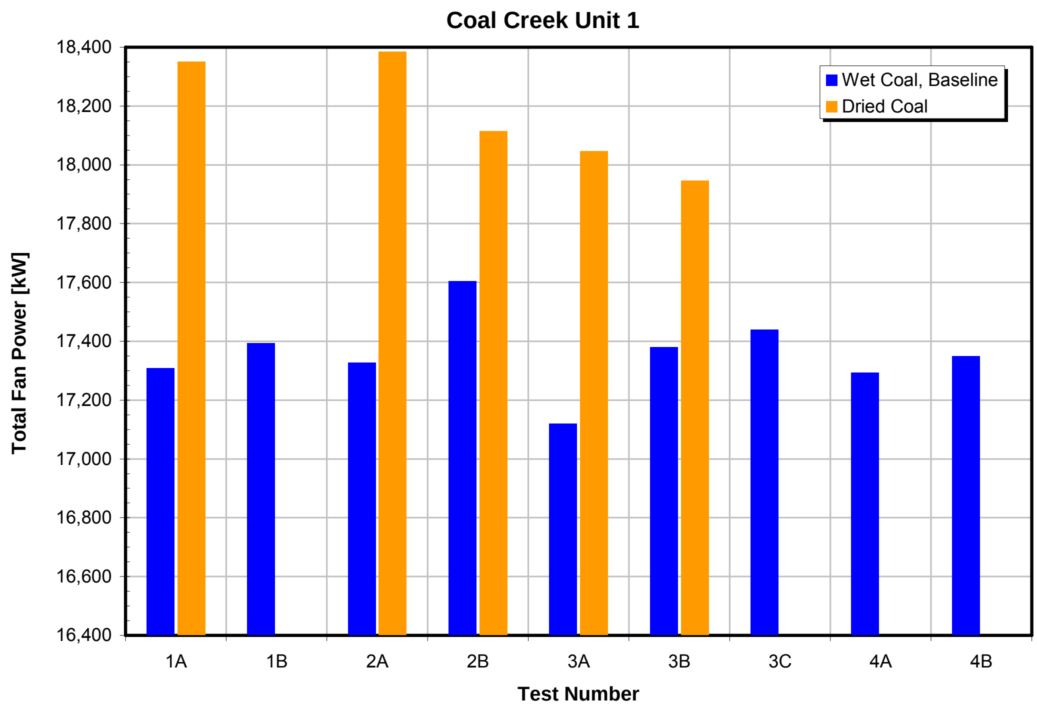

Figure 45: Total Fan Power

Total fan and mill power is presented in Figure 46. As a result of an increase in FD and PA fan power and a decrease in ID and mill power, total fan and mill power for Tests 2A to 3B conducted with dried coal was 21,671 kW, which is approximately 324 KW or 1.5 percent higher, compared to the wet coal baseline (see Figure 48). When compared to operation with constant speed ID fan drives, total fan and mill power for wet coal baseline tests is approximately 13 percent lower.

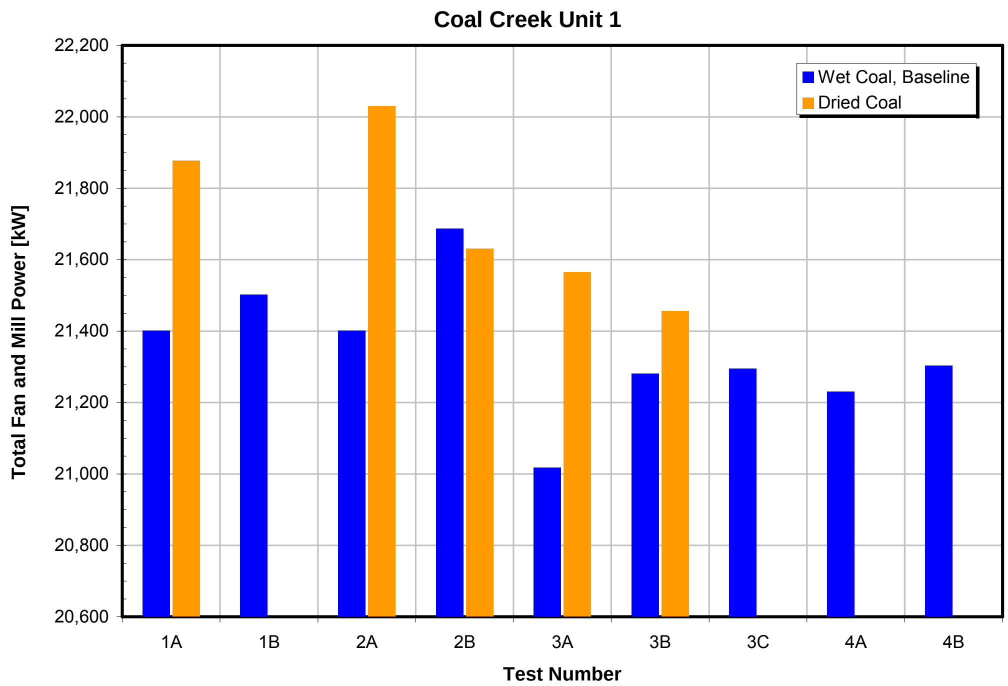

Figure 46: Total Fan and Mill Power

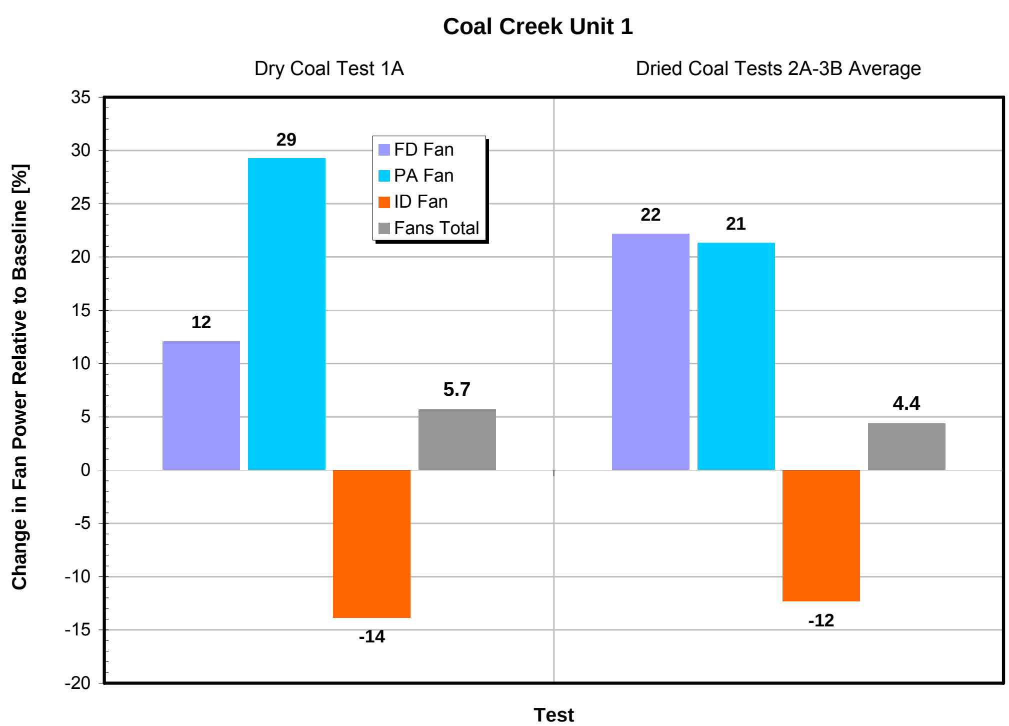

Figure 47: Change in Fan Power Relative to Baseline

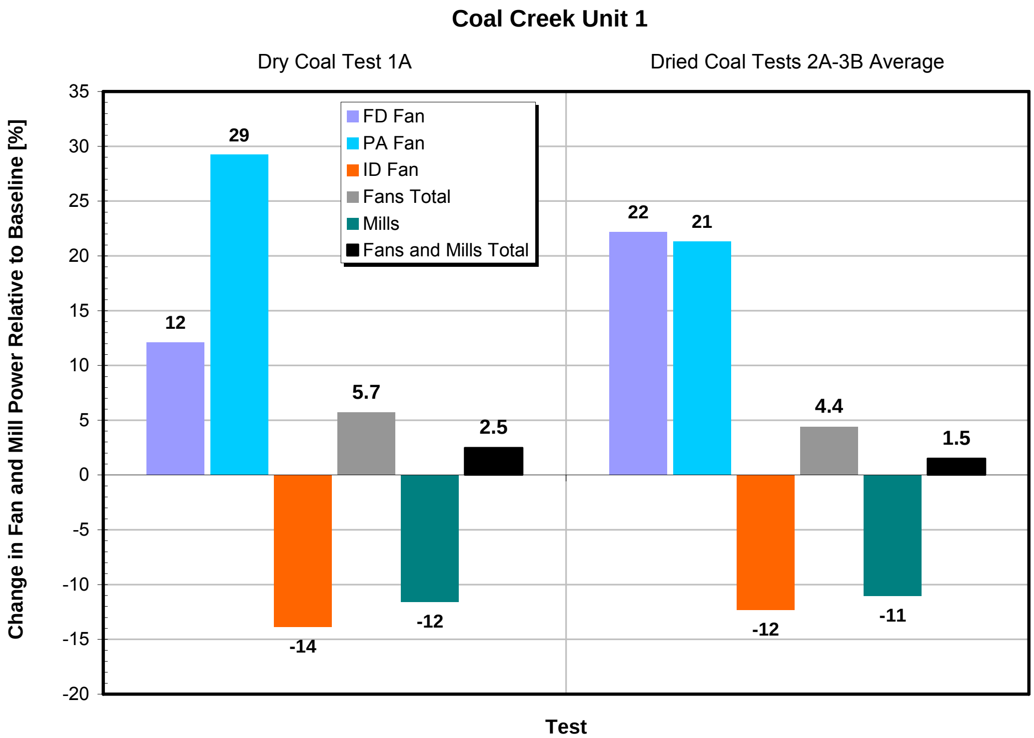

Figure 48: Change in Fan and Mill Power Relative to Baseline

7.4. Unit Performance

As discussed in Section 6 under “Test Procedure,” two series of controlled tests were performed at Coal Creek with wet and dried lignite to determine effect of reduced coal moisture content on unit performance, emissions and operation. Wet lignite was fired during first, baseline, test series. The second test series was performed after the commercial coal drying system, DryFining™, was commissioned, using dried and cleaned lignite where the segregation stream was cleaned by air jigs before being mixed with the product stream.

The unit was kept at steady state operating conditions during the test. Turbine throttle pressure was set at 2,520 psig with control valves at VWO, main steam temperature at 1,000°F, and reheat steam temperature at 1,005°F. Boiler excess O_2 was maintained close to 2.6 percent. During baseline tests conducted with wet coal in September 2009, turbine cycle was isolated by switching auxiliary steam extractions to Unit 2 while testing was performed on Unit 1, and vice versa. However, during tests conducted with dried coal in March/April 2010 Unit 2 was in outage so Unit 1 (test unit) was carrying all station loads in addition to providing auxiliary extraction steam. Therefore, for tests with dried coal, cycle isolation was not possible and values of turbine cycle heat rate calculated by the plant OPM system have to be corrected for auxiliary cycle extractions and for station load normally carried by Unit 2. Sootblowing was out of service during both test series and boiler was cleaned between the tests. For baseline tests with wet coal, pressure differential in a scrubber was maintained at 6.5 “wg for Unit 1 and at 5.5” wg for Unit 2. For tests with dried coal scrubber pressure differential for Unit 1 was maintained at 8.5” wg. Flue gas mercury concentration and speciation were measured in both test series using sCEMs and sorbent traps. The plant monitor was calibrated in October 2009 and since then it is providing continuous measurement of total and elemental mercury concentration in the stack.

Baseline Tests with Wet Coal

Test procedure, measured process parameters, and sample collection points are described in subsection 6.1 of the report. Ultimate coal composition and as-received HHV, determined from coal samples collected from mill feeders (see Figures 16 and 17) for tests performed on Unit 1 are summarized in Table 10. As-received coal composition and HHV for Unit 2 coal samples, collected by automatic as-received coal sampler CS2 located in crusher building are summarized in Table 11. As-received HHV values for tests conducted at Units 1 and 2 at Coal Creek were 6,250 and 6,300 Btu/lb, respectively. Coal moisture content for both tests was almost identical; 37.12 versus 37.13 percent. Also, composition of other coal constituents was very close, standard deviation and standard error were small, indicating that coal quality remained quite constant during the baseline test with wet coal.

Table 10: As-Received Coal Composition: Unit 1 Wet Coal Baseline Tests

UNIT 1		Test Times		Coal HHV		Coal Composition							
				AR HHV	MAF HHV	C	H	S	O	N	H_2O	Ash	Total
Test	Date	Start	End	BTU/lb	BTU/lb	%	%	%	%	%	%	%	%
1A	9/15/2009	8:00	11:00	6,167	12,135	38.64	2.63	0.67	8.47	0.41	36.88	12.30	100.00
1B	9/15/2009	13:00	16:00	6,237	12,172	39.37	2.65	0.81	8.01	0.40	36.56	12.20	100.00
2A	9/16/2009	8:00	11:00	6,249	12,330	38.52	2.59	0.70	8.46	0.41	36.99	12.33	100.00
2B	9/16/2009	13:00	17:00	6,155	12,256	37.89	2.54	0.65	8.74	0.40	36.60	13.18	100.00
3A	9/17/2009	8:00	11:05	6,346	12,097	40.24	2.64	0.61	8.56	0.41	37.52	10.02	100.00
3B	9/17/2009	12:00	14:30	6,301	12,048	39.52	2.58	0.56	9.23	0.41	37.27	10.43	100.00
3C	9/17/2009	15:30	18:00	6,254	12,032	38.95	2.58	0.54	9.50	0.41	37.40	10.62	100.00
4A	9/18/2009	8:30	11:30	6,339	12,132	39.48	2.65	0.54	9.16	0.42	37.74	10.01	100.00
4B	9/19/2009	12:30	15:45	6,207	12,114	38.79	2.59	0.61	8.84	0.41	37.08	11.68	100.00
Average				**6,251**	**12,146**	**39.04**	**2.61**	**0.63**	**8.77**	**0.41**	**37.12**	**11.42**	**100.00**
Standard Deviation				68.63	95.72	0.69	0.04	0.09	0.46	0.01	0.40	1.17	2.86
Standard Error [%]				1.10	0.79	1.76	1.48	13.83	5.27	1.47	1.09	10.24	35.14

Table 11: As-Received Coal Composition: Unit 2 Wet Coal Baseline Tests

UNIT 2		Test Times		Coal HHV									
				AR HHV	MAF HHV	C	H	S	O	N	H_2O	Ash	Total
Test	Date	Start	End	BTU/lb	BTU/lb	%	%	%	%	%	%	%	%
5A	9/21/2009	8:00	11:00	6,304	12,019	39.66	2.69	0.67	9.02	0.41	37.18	10.37	**100.00**
5B	9/21/2009	13:00	16:00	6,304	12,019	39.66	2.69	0.67	9.02	0.41	37.18	10.37	**100.00**
6A	9/22/2009	8:15	11:15	6,292	12,116	39.09	2.71	0.68	9.03	0.42	37.02	11.05	**100.00**
Average				**6,300**	**12,051**	**39.47**	**2.70**	**0.67**	**9.02**	**0.41**	**37.13**	**10.60**	**100.00**
Standard Deviation				6.93	56.14	0.33	0.01	0.01	0.01	0.01	0.09	0.39	**0.84**
Standard Error [%]				0.11	0.47	0.83	0.43	0.86	0.06	1.40	0.25	3.70	**7.53**

Information on coal composition and HHV was used in combination with other process data (Subsection 7.1 "Boiler and Plant Operating Parameters") to calculate APH air leakage, boiler efficiency, turbine cycle heat rate, and net unit heat rate. Plant OPM was used in scenario mode to calculate values of boiler efficiency and net unit heat rate by several methods. Boiler efficiency was calculated using ASME PTC 4.1 Heat Loss ($\eta_{B,ASME,PTC4.1}$) and Boiler/Turbine Cycle Efficiency (BTCE) methods ($\eta_{B,BTCE}$). Actual (test) value of gross turbine cycle heat rate ($HR_{CYCLE,GROSS}$) was calculated according to ASME PTC6.1, and corrected to baseline (design) operating conditions ($HR_{CYCLE,GROSS}^{CORR}$) using Group 1 and Group 2 corrections. Net unit heat rate was calculated according to Input/Output ($HR_{NET,IO}$) and BTCE ($HR_{NET,BTCE}$) methods. In addition to OPM calculations, values of boiler efficiency, net unit heat rate, and coal flow rate to the boiler for each test were calculated according to the BTCE method using spreadsheet-based mass and energy balance calculations developed by ERC.

In this study, unit performance parameters were calculated according to following expressions.

Boiler Efficiency

$$\eta_{B,ASME,PTC4.1} = 1 - L/(HHV + B) = Q_{STEAM}/[M_{COAL}(HHV + B)] \qquad \text{Eqn. 2}$$

$$\eta_{B,BTCE} = Q_{STEAM}/Q_{FUEL} = Q_{STEAM}/(M_{COAL}HHV) \qquad \text{Eqn. 3}$$

Gross Turbine Cycle Heat Rate

$$HR_{CYLE,GROSS} = Q_{STEAM}/P_G \qquad \text{Eqn. 4}$$

$$HR_{CYCLE,GROSS}^{CORR} = HR_{CYLE,GROSS}/CFHR$$

Net Unit Heat Rate

$$HR_{NET,IO} = Q_{FUEL}/(P_G - P_{AUX}) \qquad \text{Eqn. 5}$$

$$HR_{NET,BTCE} = HR_{CYLE,GROSS}/[\eta_{B,BTCE}(1 - P_{AUX}/P_G)] \qquad \text{Eqn. 6}$$

$$HR_{NET,BTCE} = HR_{CYLE,GROSS}(1 - B/HHV)/[\eta_{B,ASME,PTC4.1}(1 - P_{AUX}/P_G)] \qquad \text{Eqn. 7}$$

Where:

B	Heat credits to boiler
L	Energy losses from boiler
Q_{STEAM}	Heat transferred in boiler to steam
Q_{FUEL}	Heat input with fuel to boiler ($Q_{FUEL} = M_{COAL}HHV$)
M_{COAL}	Coal flow rate to boiler
P_G	Gross power output
P_{AUX}	Station service load
CFHR	Combined heat rate correction factor for Group 1 and 2 corrections

Please note that $\eta_{B,ASME,PTC4.1} \neq \eta_{B,BTCE}$ (unless B = 0), therefore, value of boiler efficiency calculated by the ASME PTC4.1 heat loss method cannot be directly substituted into expression for $HR_{NET,BTCE}$ (Eqn.16) without making appropriate correction (see Eqn. 17), because

$$HR_{NET,BTCE} \neq HR_{CYLE,GROSS}/[\eta_{B,ASME,PTC4.1}(1 - P_{AUX}/P_G)] \qquad \text{Eqn. 8}$$

Values of boiler efficiency, calculated by plant OPM according to the BTCE and ASME PTC4.1 methods and by the ERC spreadsheets for wet coal baseline tests performed at Units 1 and 2 at Coal Creek are compared in Figures 49 and 50 and summarized in Table 18. Boiler efficiency values for Unit 1 calculated by ERC were determined by using value of APH gas outlet temperature measured by a thermocouple grid. Flue gas temperature measured by plant instrumentation was on average 8°F higher, compared to grid measurements. This temperature difference results in 0.26%-point lower boiler efficiency, 0.32 percent higher net unit heat rate, and 0.36 percent higher coal flow rate.

Boiler efficiency values calculated by different methods for individual tests are very close, except for Test 6A performed at Unit 2. Average values of boiler efficiency for Unit 1, presented in Table 12, are virtually identical. For Unit 1 average value of boiler efficiency is 78.67 percent. For Unit 2, there is more variation in average values of boiler efficiency calculated by different methods, compared to Unit 1. Average value of boiler efficiency for Unit 2 is 77.27 percent, 1.4%-point lower compared to Unit 1.

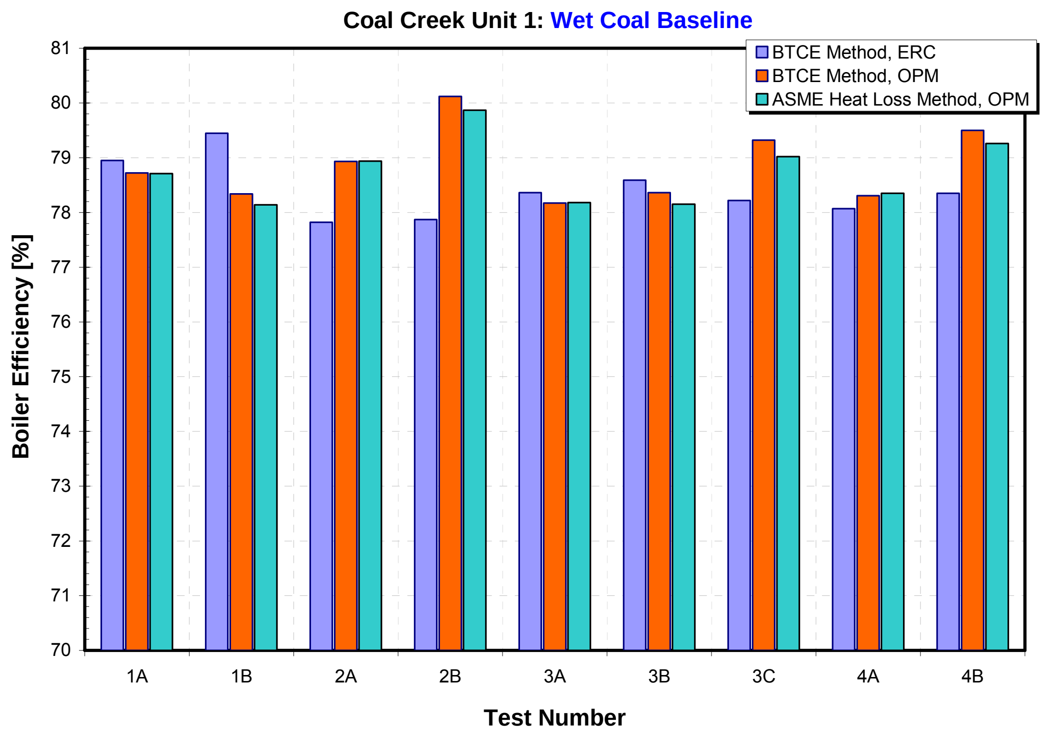

Figure 49: Boiler Efficiency for Wet Coal Baseline Test: Unit 1

Test (actual) and corrected values of turbine cycle heat rate are compared in Figures 51 and 52 and summarized in Table 13. Owning to cycle isolation, calculated values of HR_{CYCLE} and HR_{CYCLE}^{CORR} were quite constant during the test. Also, standard deviation and standard error were very small. For Unit 1 average HR_{CYCLE} = 7,664 Btu/kWh and HR_{CYCLE}^{CORR} = 7,708 Btu/kWh. For Unit 2, average HR_{CYCLE} = 7,872 Btu/kWh and HR_{CYCLE}^{CORR} = 7,917 Btu/kWh. Turbine cycle heat rate (actual and corrected) for Unit 2 was approximately 208 Btu/kWh or 2.7 percent higher compared to Unit 1 because turbine upgrade, performed on Unit 1 prior to the baseline test, resulted in better turbine cycle performance.

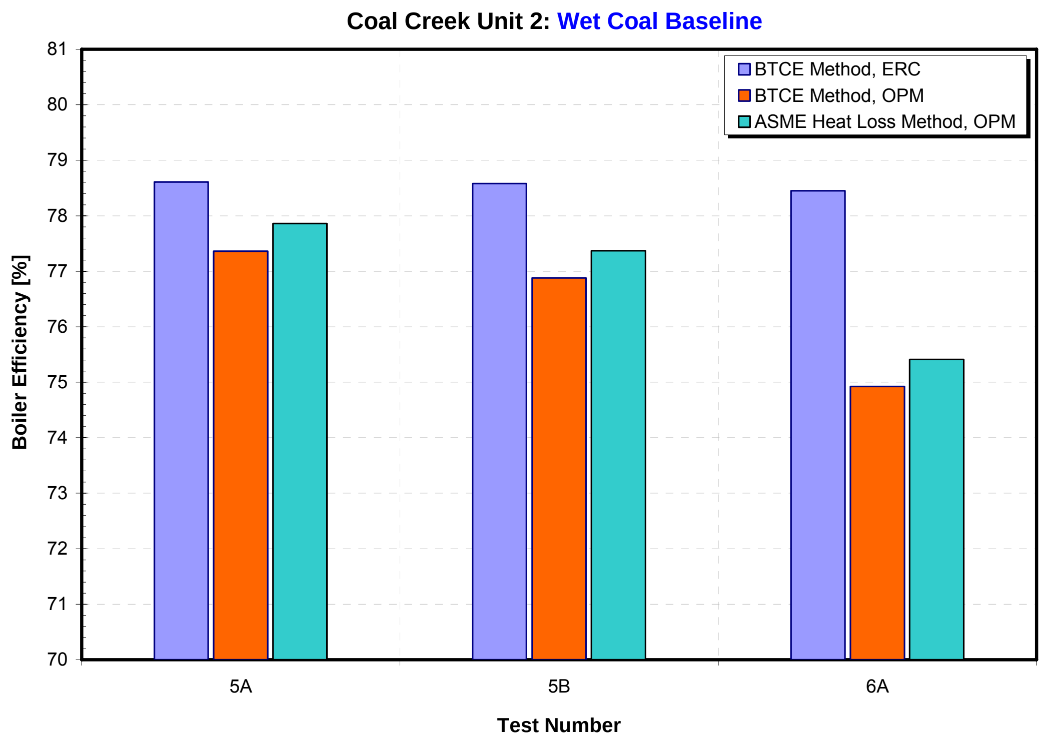

Figure 50: Boiler Efficiency for Wet Coal Baseline Test: Unit 2

Table 12: Boiler Efficiency for Baseline Test with Wet Coal: Units 1 and 2

UNIT 1	Boiler Efficiency			UNIT 2	Boiler Efficiency		
	BTCE, ERC	BTCE, OPM	ASME Heat Loss,		BTCE, ERC	BTCE, OPM	ASME Heat Loss,
	%	%			%	%	%
Average	**78.41**	**78.86**	**78.74**	**Average**	**78.55**	**76.39**	**76.88**
Standard Deviation	0.52	0.66	0.60	**Standard Deviation**	0.09	1.29	1.30
Standard Error [%]	0.7	0.8	0.8	Standard Error [%]	0.1	1.7	1.69

Net unit heat rate values, calculated by different methods, are compared in Figures 53 and 54 and summarized in Table 14. For Unit 1, values of HR_{NET} calculated for individual tests by different methods are close (even for the Input/Output method), except for Test 2B where OPM values are lower. As presented in Table 14 average values of net unit heat rate for Unit 1 calculated by different methods are virtually identical. Overall average value of HR_{NET} for Unit 1 is 10,465 Btu/kWh. For Unit 2, there is more variation in HR_{NET} values calculated by different methods, compared to Unit 1. Overall average value of net unit heat rate for Unit 2 is 10,906 Btu/kWh, approximately 440 Btu/kWh or 4.2 percent higher compared to Unit 1.

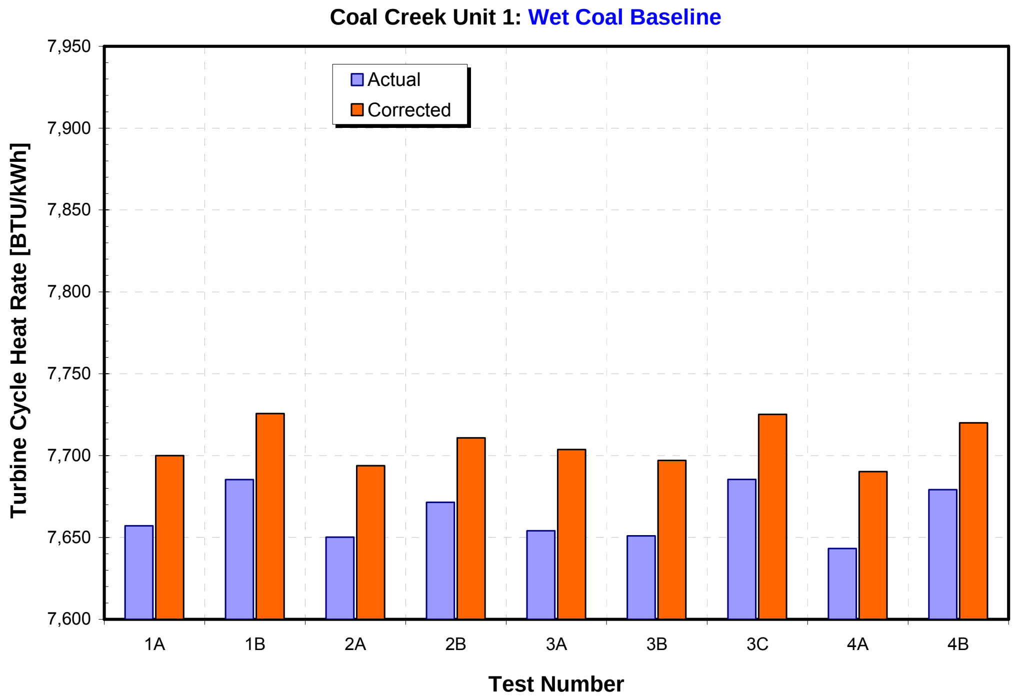

Figure 51: Test and Corrected Values of Turbine Cycle Heat Rate: Unit 1

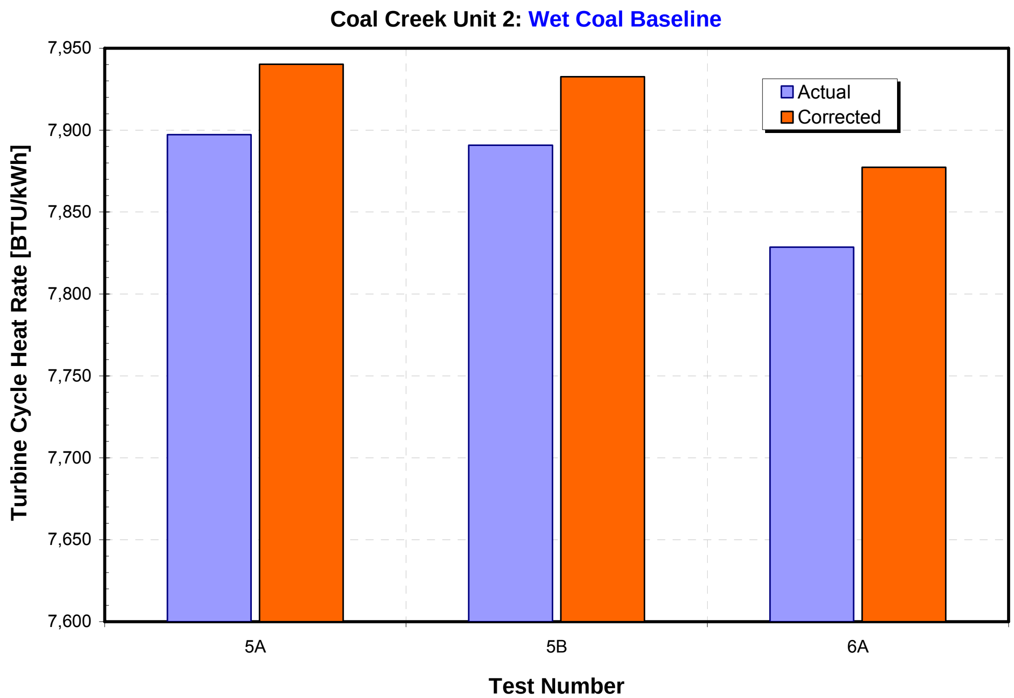

Figure 52: Test and Corrected Values of Turbine Cycle Heat Rate: Unit 2

Table 13: Actual and Corrected Turbine Cycle Heat Rate: Units 1 and 2

UNIT 1	Turbine Cycle Heat Rate		UNIT 2	Turbine Cycle Heat Rate	
	HR_{cycle}	$HR_{cycle,corr}$		HR_{cycle}	$HR_{cycle,corr}$
	BTU/kWh	BTU/kWh		BTU/kWh	BTU/kWh
Average	**7,664**	**7,708**	**Average**	**7,872**	**7,917**
Standard Deviation	16	13	**Standard Deviation**	38	34
Standard Error [%]	0.2	0.2	Standard Error [%]	0.5	0.4

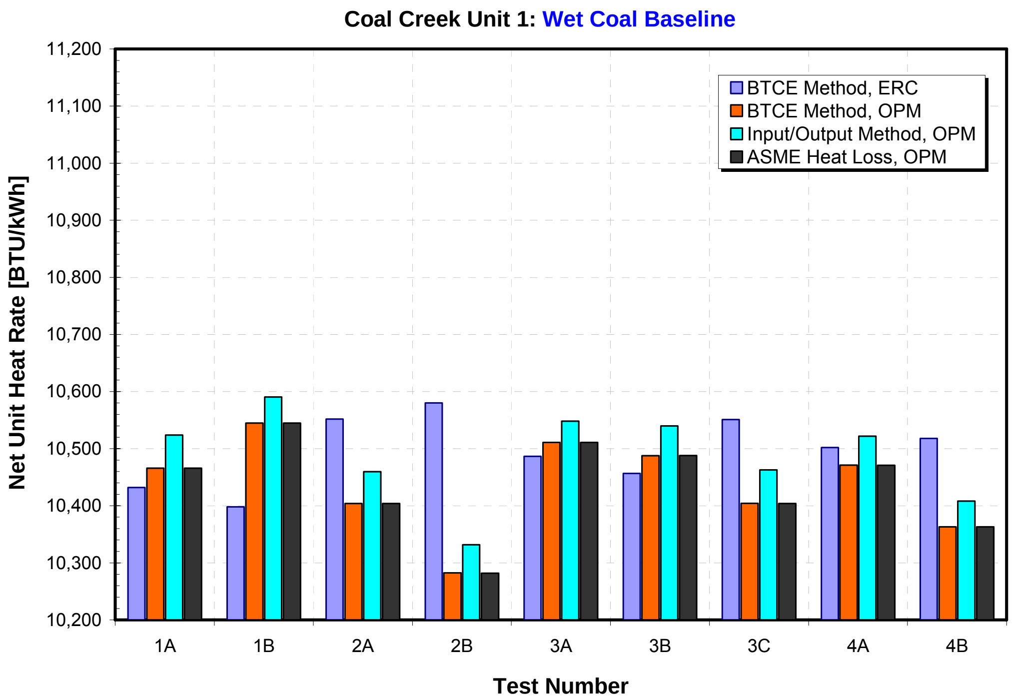

Figure 53: Net Unit Heat Rate: Unit 1

Net unit heat rate is higher for Unit 2 compared to Unit 1 because boiler efficiency for Unit 2 is lower and turbine cycle heat rate is higher, compared to Unit 1.

Values of net unit efficiency, calculated by different methods, are compared in Figures 55 and 56, and summarized in Table 15. Net unit efficiency (η_{NET}) was calculated by using following expression.

$$\eta_{NET} = 3{,}412/HR_{NET} \times 100 \qquad \text{Eqn. 9}$$

Since η_{NET} is an inverse of net unit heat rate, the same comments apply for net unit efficiency as for net unit heat rate. Average values of net unit efficiency for Unit 1, presented in Table 15, are almost identical. Overall average value of η_{NET} for Unit 1 is 32.60 percent. For Unit 2, variation in η_{NET} values calculated by different methods is larger. Overall average value of net unit efficiency for Unit 2 is 31.29 percent, 1.31%-point lower compared to Unit 1.

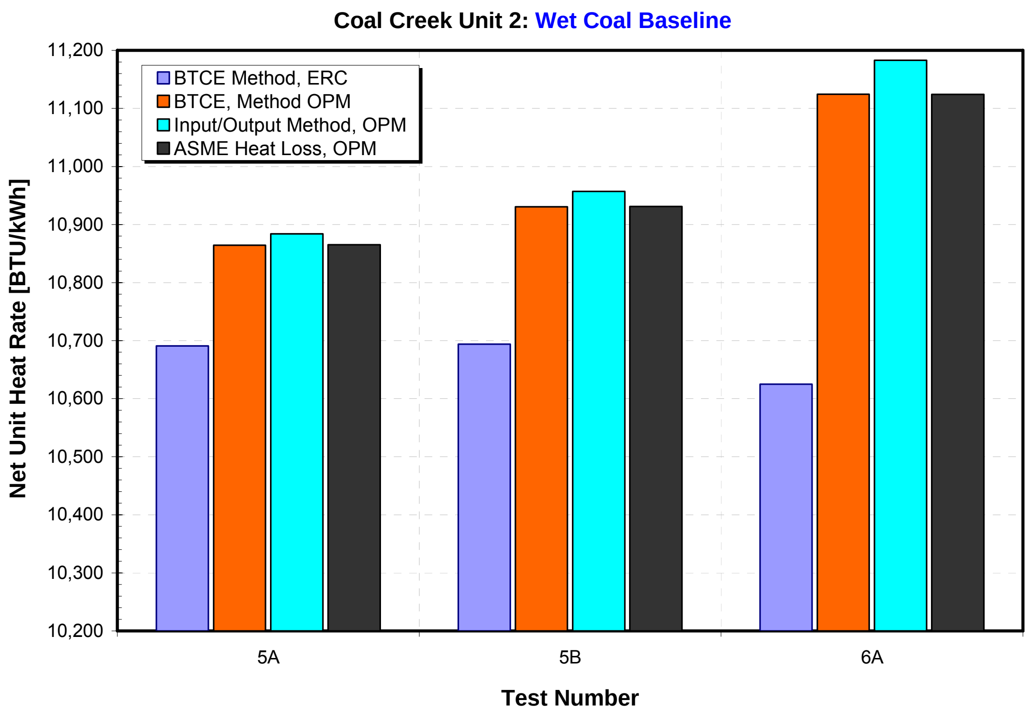

Figure 54: Net Unit Heat Rate: Unit 2

Table 14: Net Unit Heat Rate for Baseline Test with Wet Coal: Units 1 and 2

UNIT 1	Net Unit Heat Rate				UNIT 2	Net Unit Heat Rate			
	BTCE, ERC	BTCE, OPM	Input/Output, OPM	BTCE, ASME Heat Loss, OPM		BTCE, ERC	BTCE, OPM	Input/Output, OPM	BTCE, ASME Heat Loss, OPM
	BTU/kWh	BTU/kWh	BTU/kWh	BTU/kWh		BTU/kWh	BTU/kWh	BTU/kWh	BTU/kWh
Average	**10,497**	**10,437**	**10,487**	**10,437**	**Average**	**10,670**	**10,973**	**11,008**	**10,973**
Standard Deviation	60	82	80	82	**Standard Deviation**	39	135	156	135
Standard Error [%]	0.6	0.8	0.8	0.8	Standard Error [%]	0.4	1.2	1.4	1.2

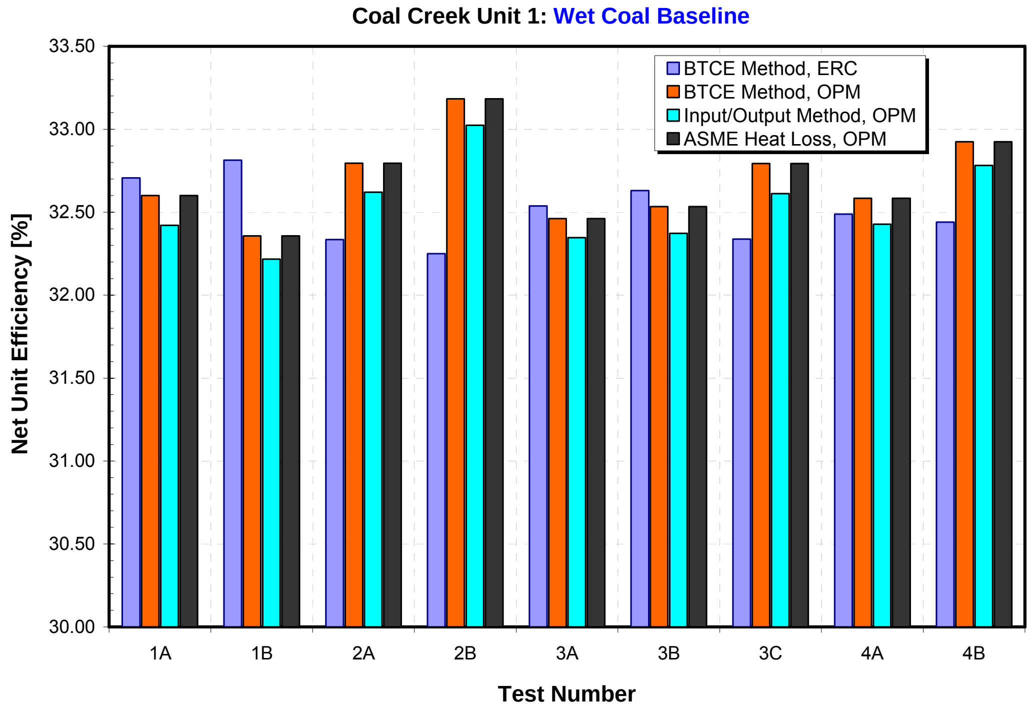

Figure 55: Net Unit Efficiency: Unit 1

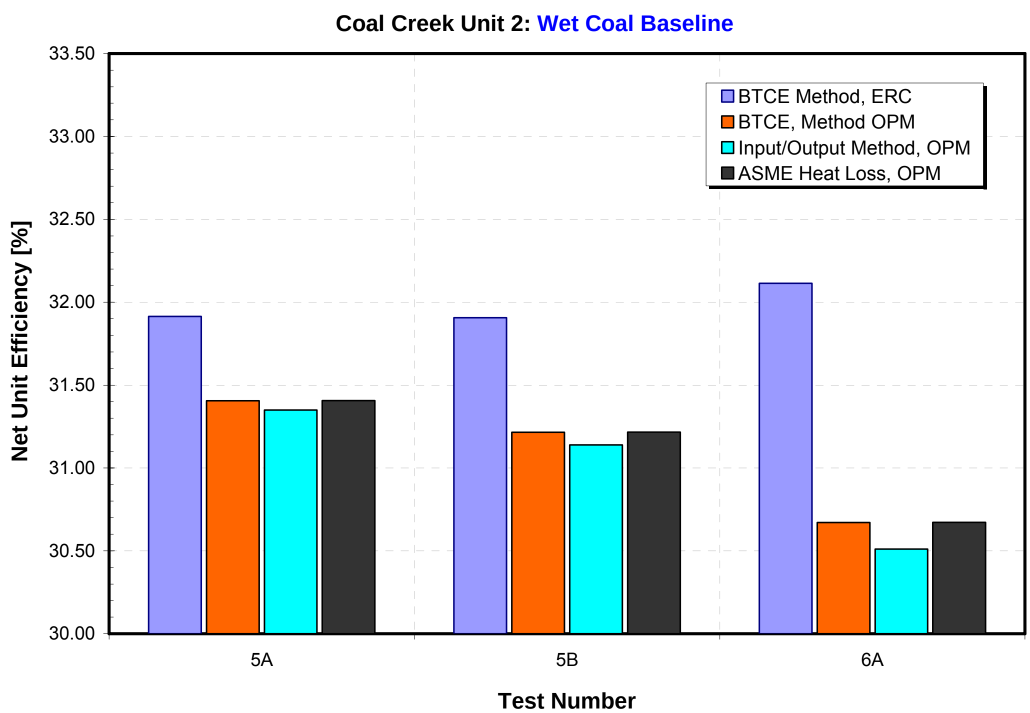

Figure 56: Net Unit Efficiency: Unit 2

Table 15: Net Unit Efficiency for Baseline Test with Wet Coal: Units 1 and 2

UNIT 1	Net Unit Efficiency				UNIT 2	Net Unit Efficiency			
	BTCE, ERC	BTCE, OPM	Input/Output, OPM	BTCE, ASME Heat Loss, OPM		BTCE, ERC	BTCE, OPM	Input/Output, OPM	BTCE, ASME Heat Loss, OPM
	BTU/kWh	BTU/kWh	BTU/kWh	BTU/kWh		BTU/kWh	BTU/kWh	BTU/kWh	BTU/kWh
Average	**32.50**	**32.69**	**32.53**	**32.69**	**Average**	**31.98**	**31.09**	**31.00**	**31.10**
Standard Deviation	0.19	0.26	0.25	0.26	**Standard Deviation**	0.12	0.38	0.44	0.38
Standard Error [%]	0.58	0.78	0.77	0.78	Standard Error [%]	0.37	1.22	1.41	1.23

Comparison of coal flow rate measured by mill feeders and determined by ERC's spreadsheet-based mass and energy balance calculation is presented in Figures 57 and 58, and summarized in Table 16. For Unit 1, average flow rate of coal measured by mill feeders was 944 klb/hr, while average calculated value was 938 klb/hr. The difference (bias) relative to the measured value (ΔM_{COAL}), calculated from Equation 20, is 1.36 percent. Such level of agreement is considered excellent considering magnitude of coal flow and equipment size. Differences (biases) calculated for individual Unit 1 tests are shown in Figure 59.

$$\Delta M_{COAL} = (M_{COAL,MEASURED} - M_{COAL,CALCULATED})/M_{COAL,MEASURED} \times 100 \quad \text{Eqn. 10}$$

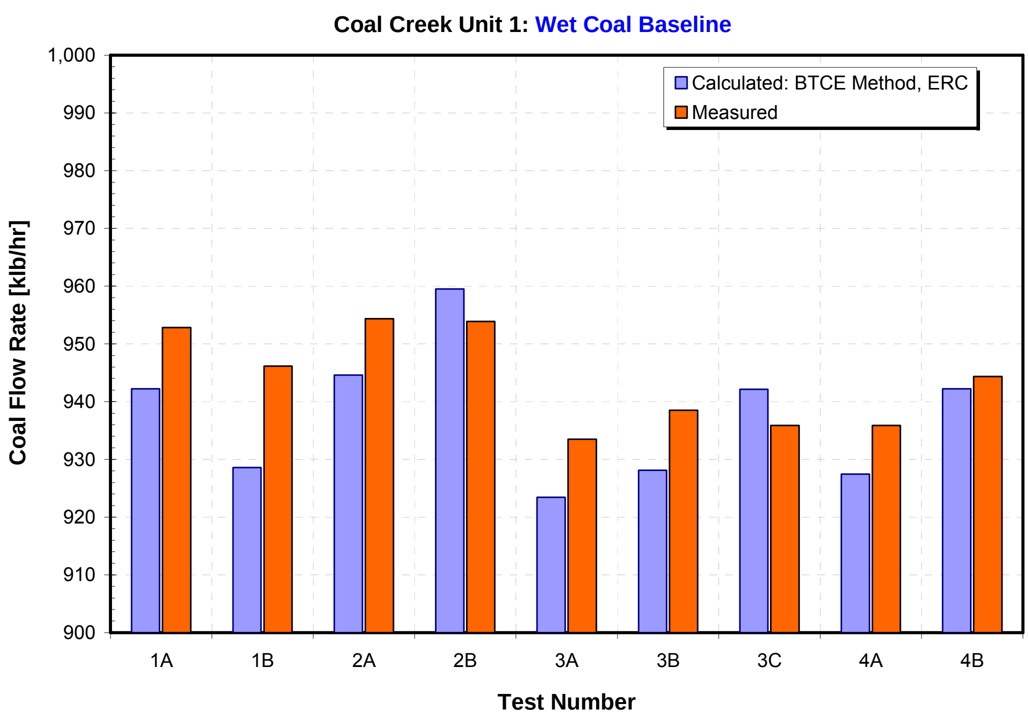

Figure 57: Measured and Calculated Coal Flow: Unit 1

The average flow rate of coal measured by mill feeders for Unit 2 was 982 klb/hr, while average calculated value was 953 klb/hr, resulting in difference relative to the measured value of 3.74 percent. This difference is larger than expected but consistent with differences in boiler efficiency determined for Tests 5B and 6A by plant OPM according to the ASME PTC4.1 and BTCE methods, and in net unit heat rate calculated by plant OPM according to the Input/Output method and determined by ERC according to the BTCE method. Differences in coal flow calculated for individual Unit 2 tests are presented in Figure 60. Results show difference of 1.5 percent for Test 5A, which increased to 2.7 and 4.7 percent for Tests 5B and 6A. Additional analysis of test data is needed to explain this increase.

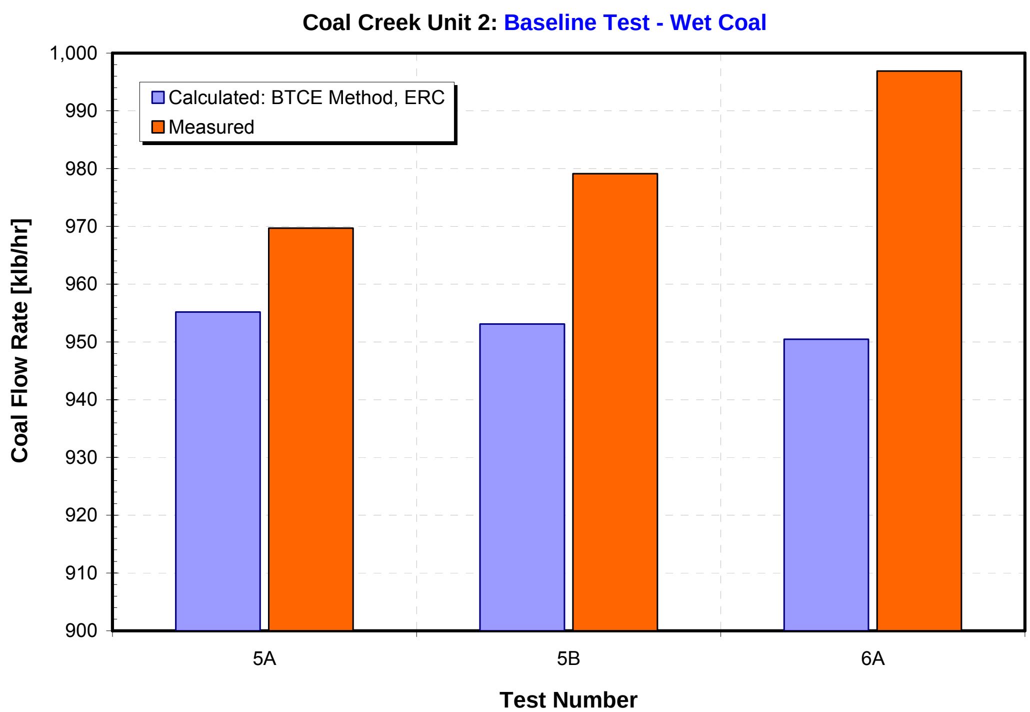

Figure 58: Measured and Calculated Coal Flow: Unit 2

Table 16: Coal Flow Rate for Baseline Test with Wet Coal: Units 1 and 2

UNIT 1		Coal Feed Rate			UNIT 2		Coal Feed Rate		
		Calculated, BTCE	Measured	Difference Relative to Measured			Calculated, BTCE	Measured	Difference Relative to Measured
Test	Date	klb/hr	klb/hr	%	Test	Date	klb/hr	klb/hr	%
Average		**938**	**944**	**1.36**	**Average**		**953**	**982**	**3.74**
Standard Deviation		60	8	0.92	**Standard Deviation**		2	14	1.63
Standard Error [%]		0.6	0.9	68	Standard Error [%]		0.2	1.4	43.6

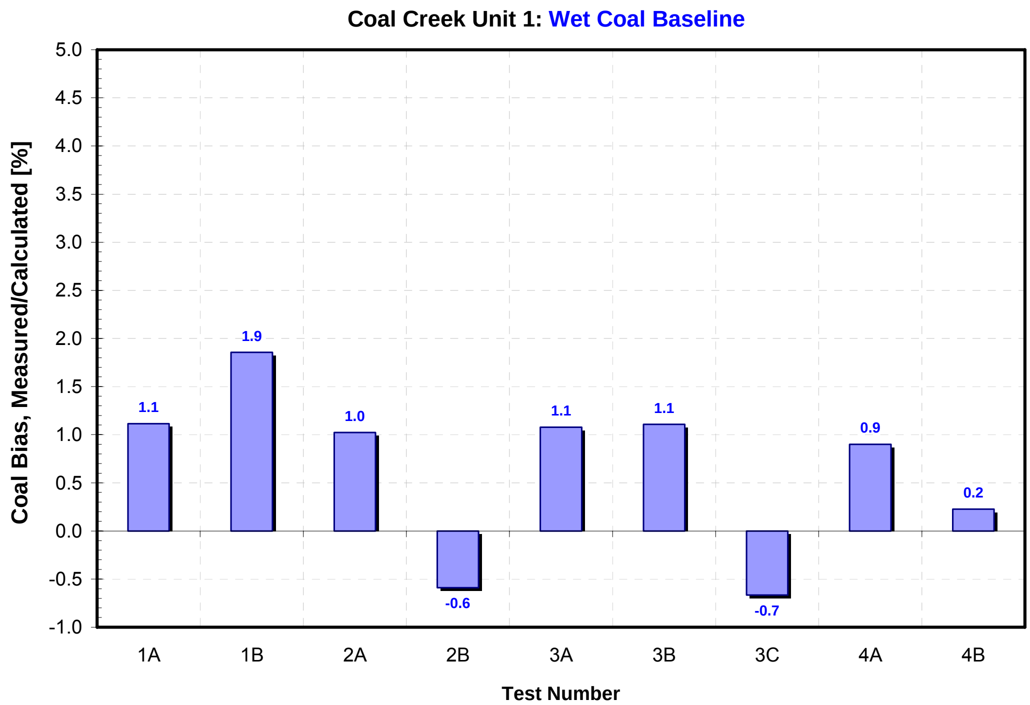

Figure 59: Difference Between Measured and Calculated Coal Flows: Unit 1

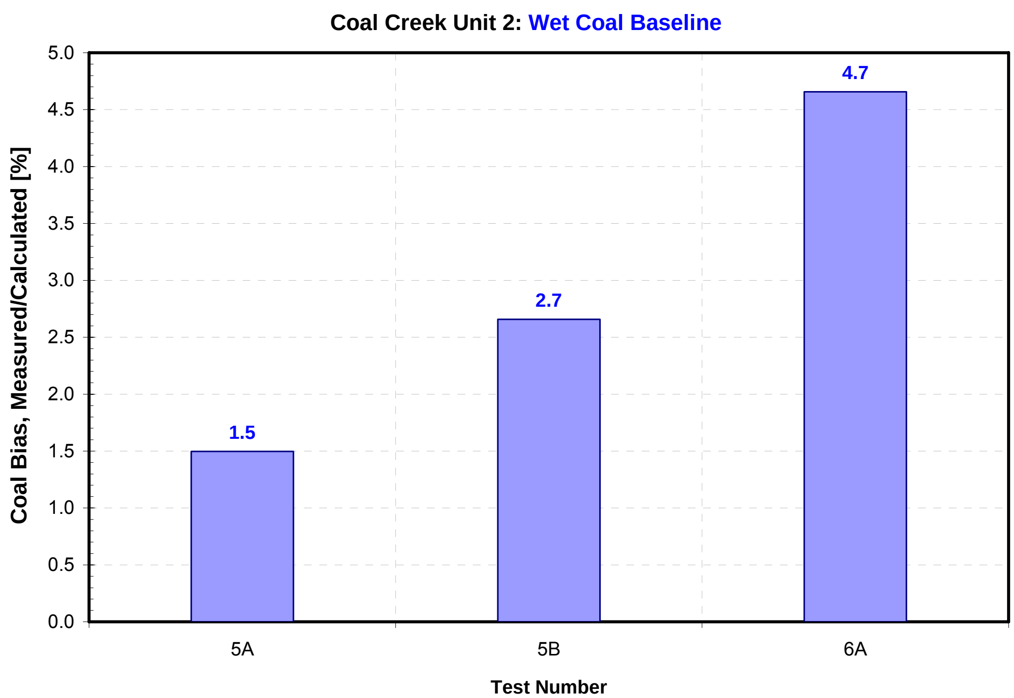

Figure 60: Difference Between Measured and Calculated Coal Flows: Unit 2

Tests with Dried Coal

Preliminary tests with dried coal were performed in March/April 2010. During the test Unit 2 was in outage and, therefore, Unit 1 (test 1) was carrying entire station load and providing steam for auxiliary steam extractions from turbine cycle. This resulted in higher station service and approximately 2 percent higher turbine cycle heat rate. Although, some of these effects could be corrected out, correction of this magnitude would introduce uncertainty in calculated turbine cycle and unit performance and effect of dried coal on unit performance. Baseline tests with dried coal are planned for second half of 2010 when both units will be in service.

8. EMISSIONS

Baseline tests with wet coal were performed in September 2009, while preliminary tests with dried coal were performed in March/April 2010 to determine effect of dried coal on emissions. For baseline tests with wet coal, pressure differential in a scrubber was set at 6.5 “wg for Unit 1. For tests with dried coal due to lover volumetric flow of flue gas it was possible to increase scrubber pressure differential for to 8.5” wg. Annual RATA was performed on plant CEM in advance of the September 2009 tests. NO_x and SO_2 concentration in the stack was measured by the plant CEM. Emission rates and CEM heat input (Q_{CEM}) were calculated according to EPA regulations by the plant emissions reporting system using CO_2 concentration measured in the stack. NO_x and SO_2 concentration, emissions rate, SO_2 mass emissions, SO_2 removal in the scrubber, and nitrogen and sulfur content in coal are summarized in Tables 17 and 18. Results show that NO_x and SO_2 concentration and emissions rates are significantly lower for tests with dried coal, compared to the wet coal baseline.

Table 17: NO_x and SO_x: Wet Coal Baseline, September 2009

Wet Coal Baseline		Nitrogen	$NO_{x,stack}$	$NO_{x,stack}$	Sulfur	$SO_{2,Scrubber\ Inlet}$	$\Delta P_{Scrubber}$	$SO_{2,stack}$	$M_{SO2,stack}$	$SO_{2,stack}$	SO_2 Removal
Test	Date	% db	ppm	lb/MBTU	% db	ppm	"wg	ppm	lb/hr	lb/MBTU	%
1A	9/15/2009	0.65	154	0.298	1.06	879	6.5	234	3,614	0.628	73.3
1B	9/15/2009	0.65	149	0.288	1.28	894	6.5	236	3,622	0.633	73.6
2A	9/16/2009	0.64	151	0.289	1.11	878	6.5	231	3,550	0.617	73.7
2B	9/16/2009	0.63	149	0.286	1.02	861	6.5	229	3,511	0.612	73.4
3A	9/17/2009	0.66	143	0.273	0.98	743	6.5	197	2,993	0.522	73.5
3B	9/17/2009	0.65	148	0.283	0.89	748	6.5	201	3,060	0.533	73.2
3C	9/17/2009	0.66	147	0.282	0.87	758	6.5	205	3,142	0.547	72.9
4A	9/18/2009	0.68	145	0.278	0.87	746	6.5	204	3,101	0.542	72.7
4B	9/19/2009	0.66	144	0.276	0.97	780	6.5	212	3,245	0.563	72.9
Average		**0.65**	**148**	**0.284**	**1.00**	**810**	**6.5**	**216**	**3,315**	**0.577**	**73.3**
Standard Deviation		0.0	3.4	0.008	0.13	66	0	15.8	257	0.0	0.4
Standard Error [%]		2.2	2.3	2.7	13.17	8	0	7.3	7.7	7.7	0.5

Table 18: NO_x and SO_x: Preliminary Tests with Dried Coal, March/April 2010

March/April 2010 Tests		Nitrogen	$NO_{x,stack}$	$NO_{x,stack}$	Sulfur	$SO_{2,Scrubber\ Inlet}$	$\Delta P_{Scrubber}$	$SO_{2,stack}$	$M_{SO2,stack}$	$SO_{2,stack}$	SO_2 Removal
Test	Date	% db	ppm	lb/MBTU	% db	ppm	"wg	ppm	lb/hr	lb/MBTU	%
1A	3/11/2010		**134**	**0.249**		**863**	**7.5**	**179**	**2,654**	**0.460**	**79.3**
2A	3/31/2010	1.30	109	0.201	1.04	715	8.5	104	1,556	0.268	85.4
2B	3/31/2010	1.30	104	0.191	1.04	695	8.5	97	1,385	0.249	86.0
3A	4/1/2010	1.30	102	0.187	1.04	735	8.5	104	1,540	0.266	85.9
3B	4/1/2010	1.30	106	0.195	1.04	716	8.5	108	1,606	0.278	84.9
Average*		**1.30**	**105**	**0.194**	**1.04**	**715**	**8.5**	**103**	**1,522**	**0.265**	**85.6**
Standard Deviation*		0.00	2.9	0.006	0.00	16	0	4.6	95	0.012	0.5
Standard Error* [%]		0.00	2.7	3.1	0.00	2	0	4.4	6.3	4.5	0.6

* Excluding Test 1A

Coal sulfur content was approximately the same for tests with wet and dried coal, 1.00 and 1.04 percent, respectively. Nitrogen content in coal for preliminary tests with dried coal was by a factor of two higher compared to the wet coal baseline, 1.30 and 0.65 percent, respectively. Total NO_x is sum of fuel NO_x, which is proportional to the fuel nitrogen content, and thermal NO_x, which is amongst other parameters dependent on flame temperature or furnace exit gas temperature (FEGT). Because FEGT for lignite-fired boilers is relatively low, 2,000 to 2,050°F for Coal Creek Unit 1, it is reasonable to assume that fuel NO_x is main contributor to the total NO_x. Therefore, if coal nitrogen content were the same for both test series, value of total NO_x for tests with dried coal, would be lower than presented in Table 18.

8.1. NO_x Emissions, Fuel Factor, and CEM Heat Input

NO_x concentration measured by the plant CEM for wet coal baseline tests and preliminary tests with dried coal is compared in Figure 61. With dried coal, NO_x concentration measured by the plant CEM was consistently lower, compared to the wet coal baseline. It has to be noted that Test 1A, performed on March 11 2010, was conducted with coal drying system running with lower thermal (drying) capacity, compared to Tests 2A to 3B and no air jig in service. Reduction in stack NO_x concentration, relative to the wet coal baseline tests, is presented in Figure 62. Results show that with dried coal NO_x was reduced by 29 percent, compared to the wet coal baseline. As discussed above, with coal nitrogen content being the same for tests with the wet and dried coals, for preliminary tests with dried coal NO_x emissions would be lower than measured resulting in larger NO_x reduction.

NO_x reduction is attributed to shift in the primary to secondary air flow ratio (see Figures 38 and 39); with dried coal primary air flow is significantly lower compared to the wet coal (see Figures 31, 32, and 33). Therefore, more secondary air is available for combustion staging and in-furnace NO_x control.

Also, with dried coal, Unit 1 was capable of achieving full load with six mills in service, compared to eight which are typically needed for wet coal. When the top mill or top two mills are not in service, combustion staging is increased and NO_x is reduced.

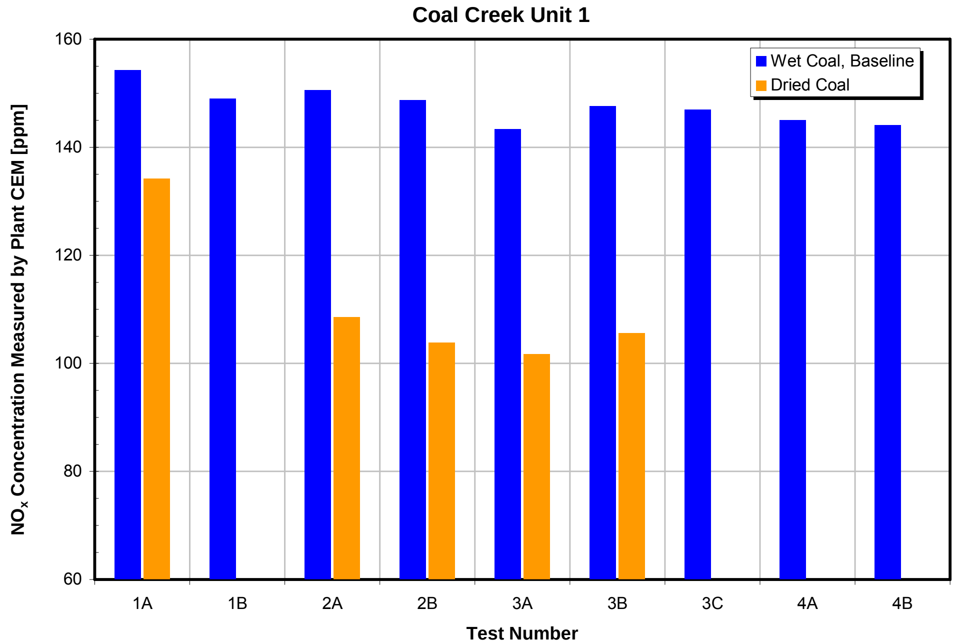

Figure 61: NO_x concentration: Wet Coal Baseline vs. Preliminary Dried Coal Tests

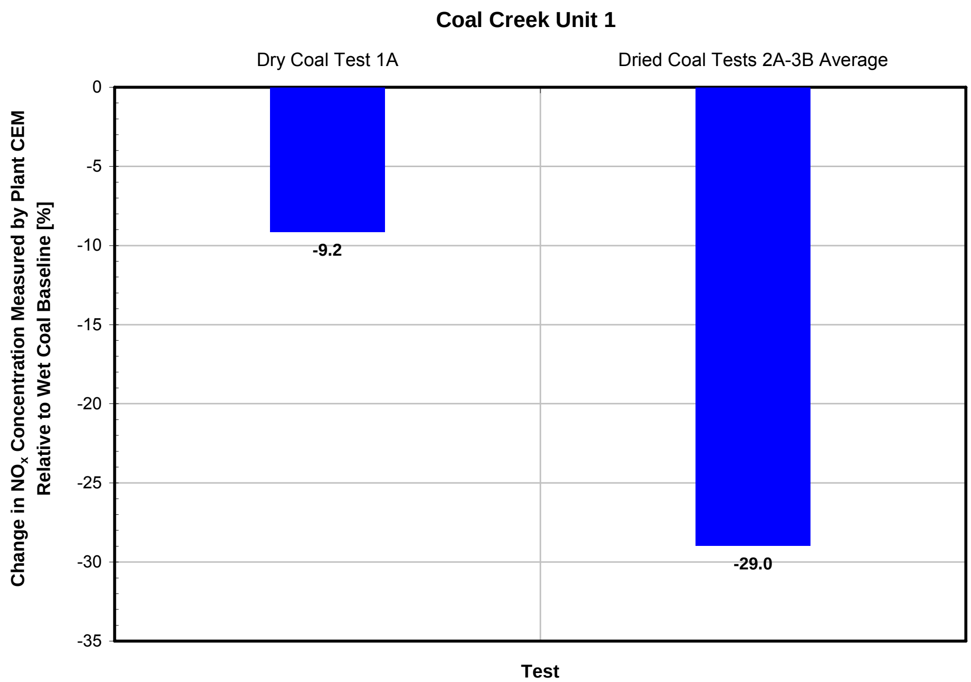

Figure 62: Reduction in Stack NO_x Concentration Relative to Wet Coal Baseline

NO_x emissions rate calculated from Equation 11 for wet coal baseline tests and preliminary tests with dried coal is compared in Figure 63. With dried coal, the NO_x emission rate was consistently lower, compared to the wet coal baseline. Reduction in NO_x emissions rate, relative to the wet coal baseline, is presented in Figure 64. With dried coal, the NO_x emission rate was reduced by approximately 32 percent, compared to the wet coal baseline. For the reasons discussed above, with coal nitrogen content being the same for tests with wet and dried coals, reduction in NO_x emissions rate would be higher.

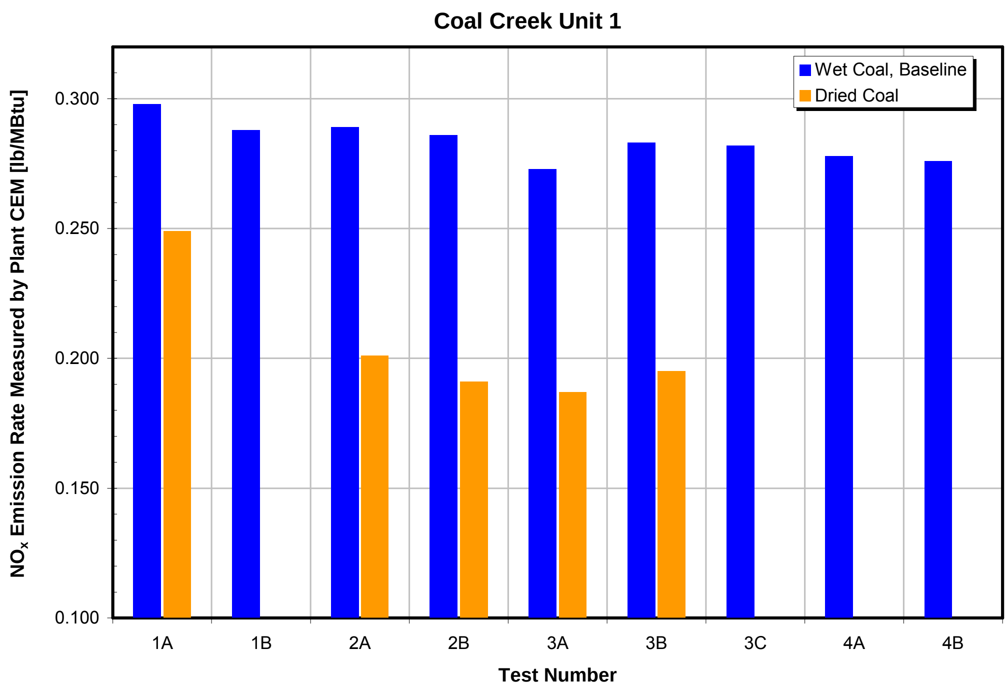

Figure 63: NO_x Emissions Rate: Wet Coal Baseline vs. Preliminary Dried Coal Tests

It has to be noted that reductions in NO_x concentration and NO_x emissions rate relative to the wet coal baseline, although being close are not exactly the same. This is attributed to CO_2 measurement uncertainty and use of default value of F_c factor (1,910 scf/MBtu). Because the F_c factor is function of coal HHV and coal carbon content (see Equation 12), the value of F_c factor and emissions rate vary as coal composition and HHV change.

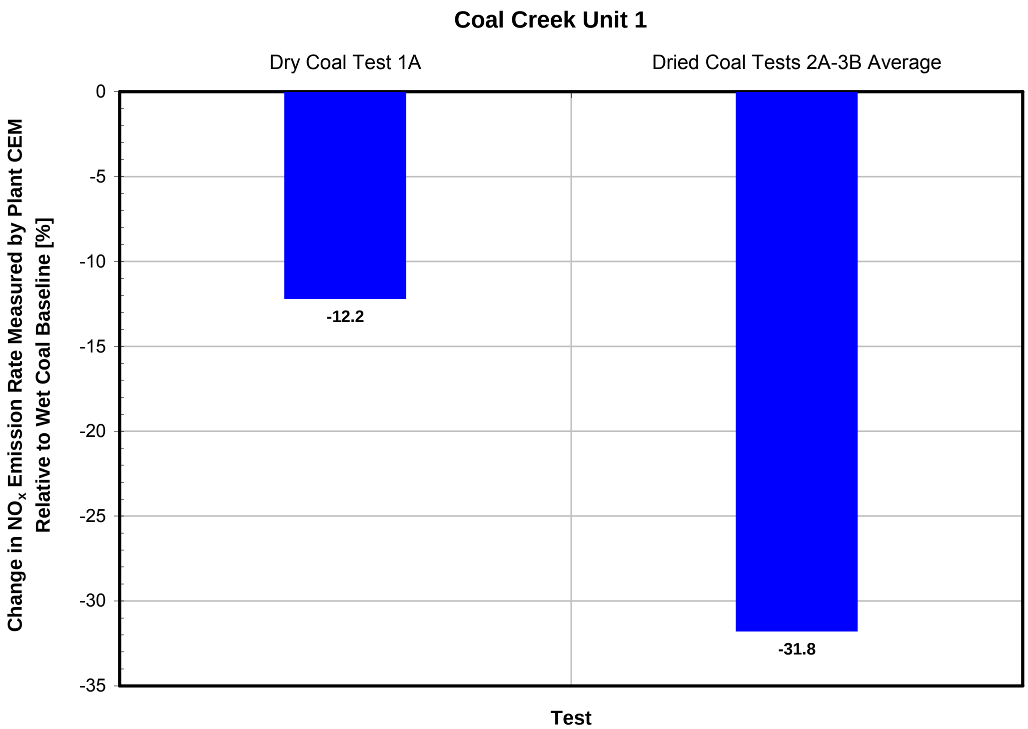

Figure 64: Reduction in NO_x Emission Rate Relative to Wet Coal Baseline

$E_{NOx} = 1.194 \times 10^{-7} C_{NOx} F_c\, 100/C$ Eqn. 11

$F_c = 3.21 \times 10^6\, C/HHV$ Eqn. 12

$Q_{CEM} = V_{Stack,STP}\, (CO_{2,Stack}/100)/F_c$ Eqn. 13

where:

E_{NOx}	NO_x emission rate, lb/MBtu
C_{NOx}	NO_x concentration, ppm
F_c	CO_2 F-Factor, scf/MBtu
C	Carbon content of coal, %
Q_{CEM}	CEM heat input, MBtu/hr
$V_{Stack,STP}$	Volumetric flue gas flow rate at standard pressure and temperature
$CO_{2,Stack}$	Measured concentration of CO_2 in flue gas, % vol wet

Values of F_c calculated from Equation 12, presented in Figure 65, show that for preliminary tests with dried coal value of F_c was significantly higher compared to the default value and value of F_c corresponding to the wet coal baseline.

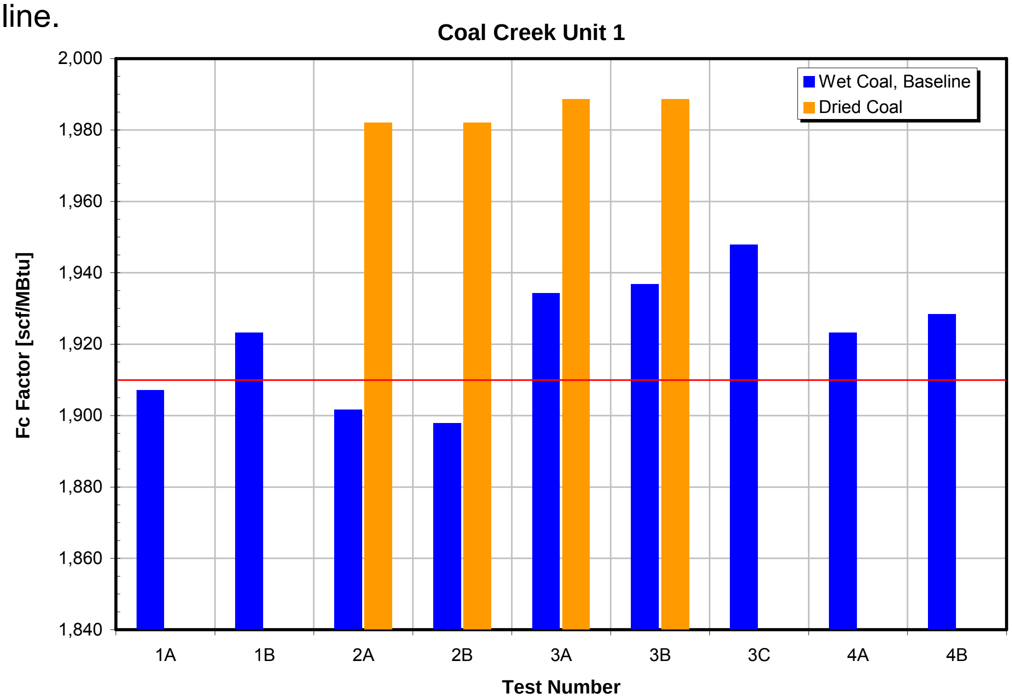

Figure 65: F_c (CO_2 F factor): Wet Coal Baseline vs. Preliminary Dried Coal Tests

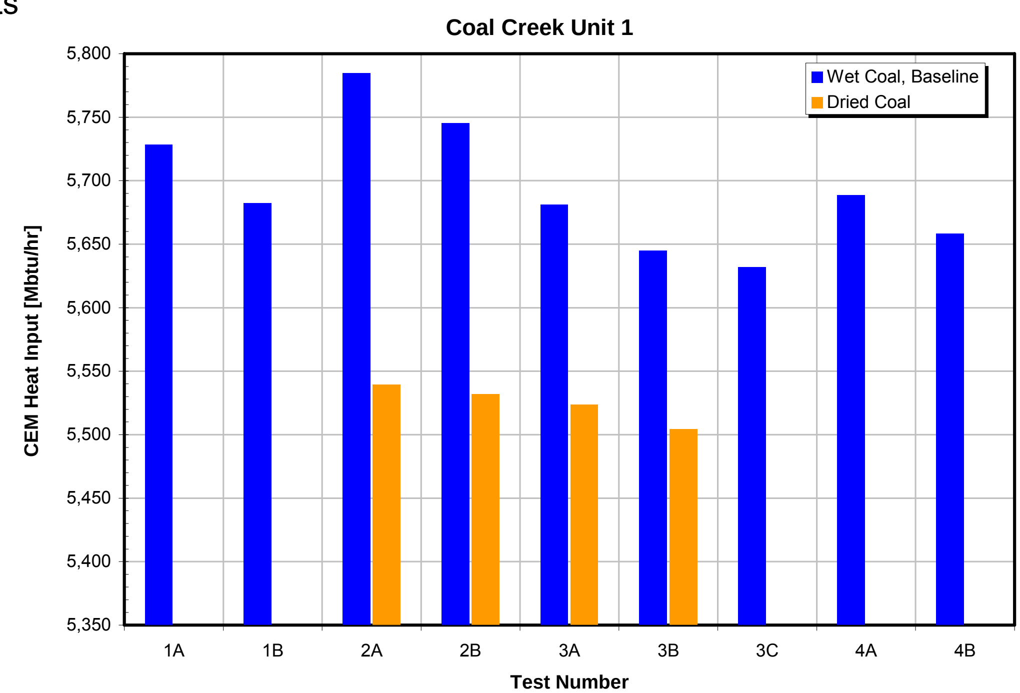

Figure 66: CEM Heat Input: Wet Coal Baseline vs. Preliminary Dried Coal Tests

CEM heat input calculated from Equation 13 using measured values of stack volumetric flow rate and CO_2 concentration, and calculated values of F_c corresponding to the wet coal baseline and preliminary tests with dried coal are compared in Figure 66. Average value of Q_{CEM} for preliminary tests with dried coal of 5,525 MBtu/hr is approximately 3 percent lower compared to average value of Q_{CEM} for the wet coal baseline of 5,694 MBtu/hr (see Table 19).

8.2. SO_2 Emissions

SO_2 concentration, measured by the plant CEM, for the wet coal baseline tests and preliminary tests with dried coal is compared in Figure 67. With dried coal, SO_2 concentration measured by the plant CEM was consistently lower, compared to the wet coal baseline. Test 1A performed on March 11, 2010 was conducted with coal drying system running with lower thermal (drying) capacity compared to Tests 2A to 3B and no air jig in service. Reduction in stack SO_2 concentration, relative to the wet coal baseline tests, is presented in Figure 68.

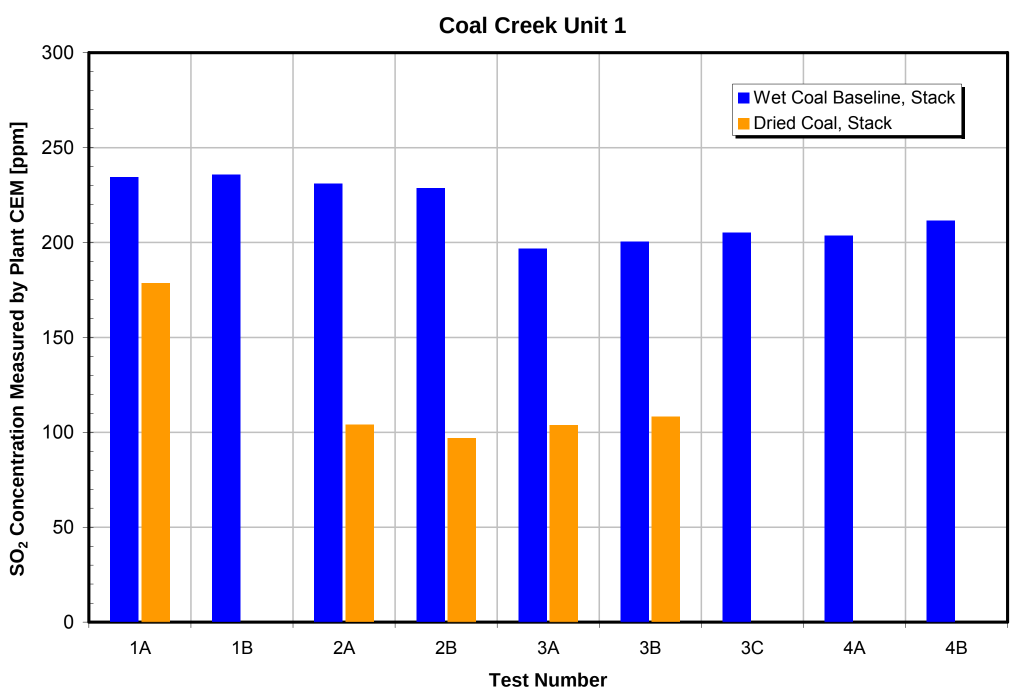

Figure 67: SO_2 Concentration: Wet Coal Baseline vs. Preliminary Dried Coal Tests

Results show that with dried coal SO_2 was reduced by more than 52 percent, compared to the wet coal baseline.

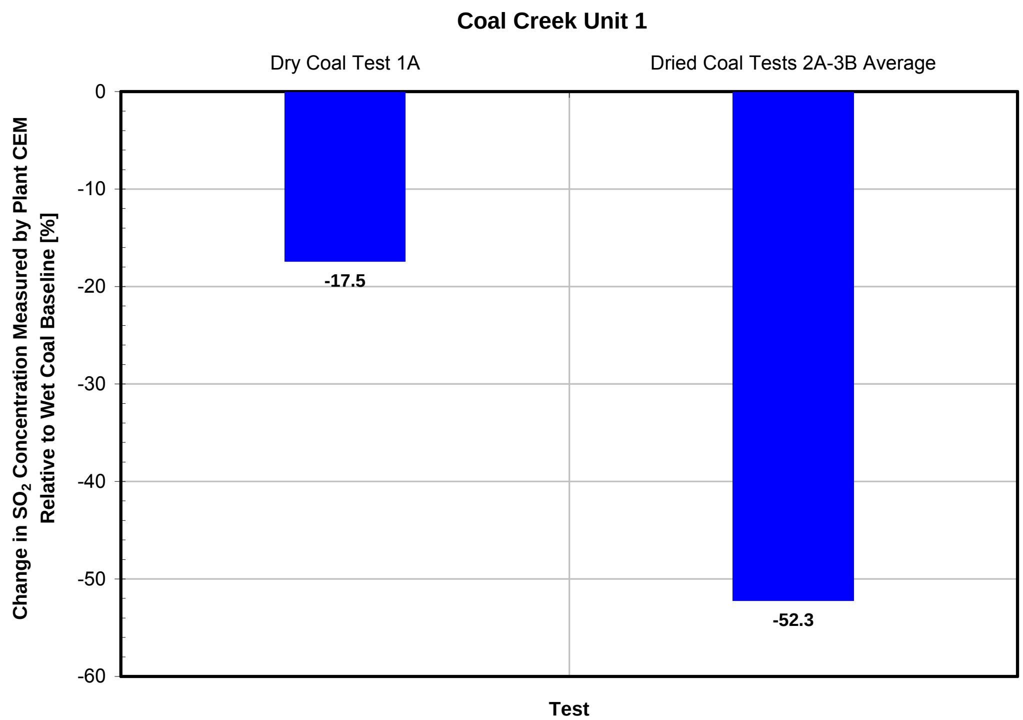

Figure 68: Reduction in Stack SO_2 Concentration Relative to Wet Coal Baseline

The SO_2 emissions rate for wet coal baseline tests and preliminary tests with dried coal are compared in Figure 69. With dried coal, the SO_2 emission rate was consistently lower, compared to the wet coal baseline. SO_2 mass emissions as pounds of emitted SO_2 per hour are presented in Figure 70. The trends are consistent with emissions rate. Reduction in SO_2 emissions rate and mass emissions, relative to the wet coal baseline, is presented in Figure 71. With dried coal, the SO_2 emissions rate was reduced by approximately 54 percent, compared to the wet coal baseline (see Table 19). The reduction in SO_2 mass emissions was virtually identical to reduction in SO_2 emission rate.

Similarly to NO_x, reductions in SO_2 concentration and SO_2 emissions rate relative to the wet coal baseline, although being very close, are not exactly the same for reasons discussed in Subsection 8.1.

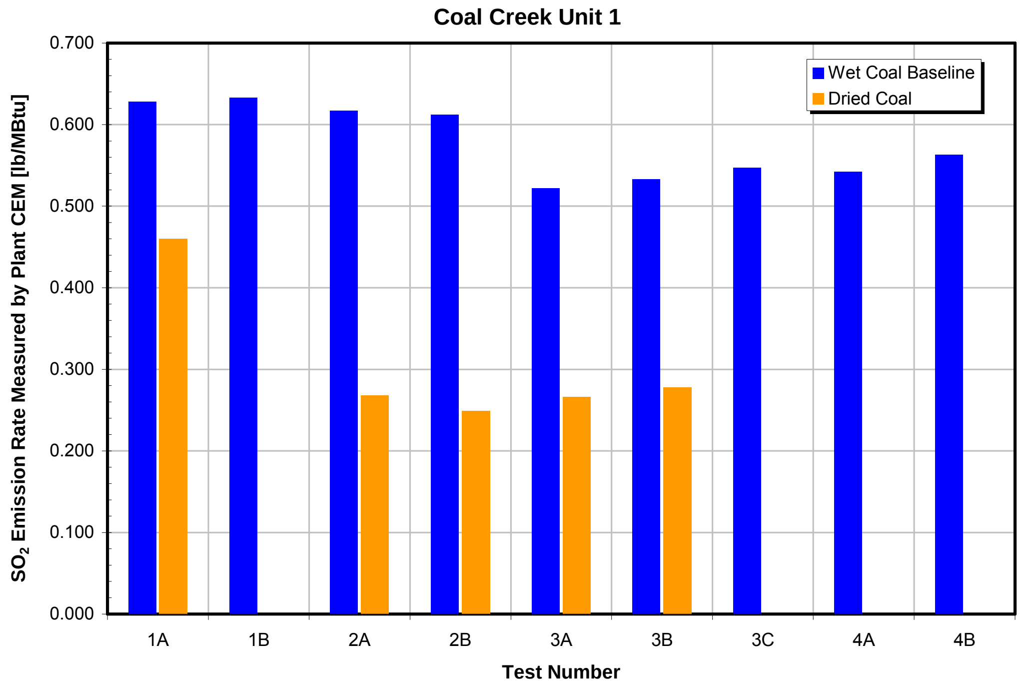

Figure 69: SO_2 Emissions Rate: Wet Coal Baseline vs. Preliminary Dried Coal Tests

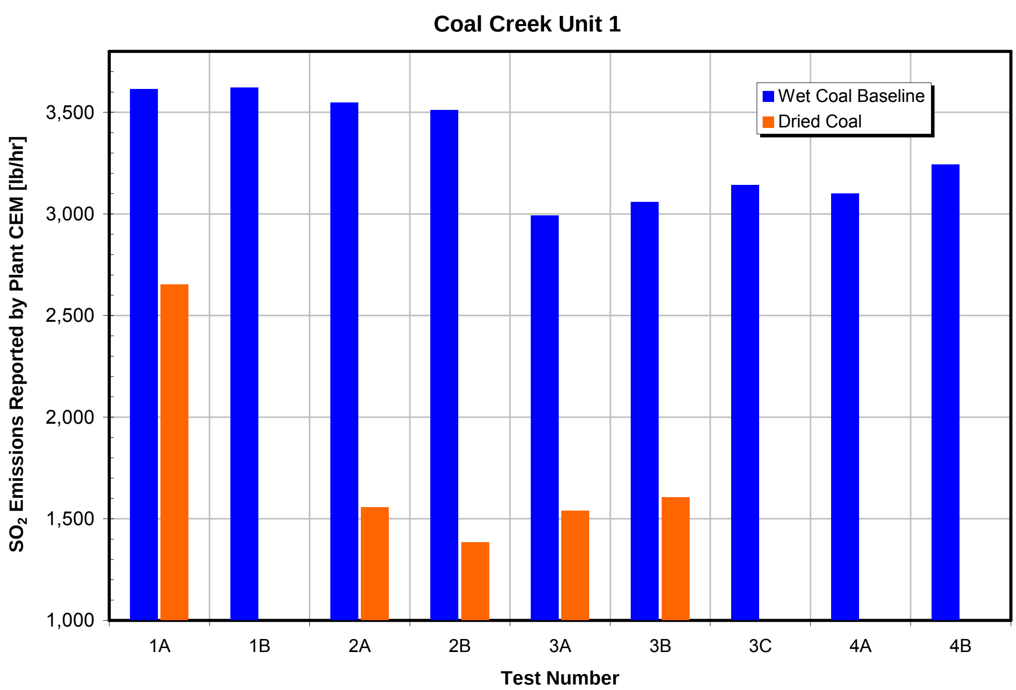

Figure 70: SO_2 Mass Emissions: Wet Coal Baseline vs. Preliminary Dried Coal Tests

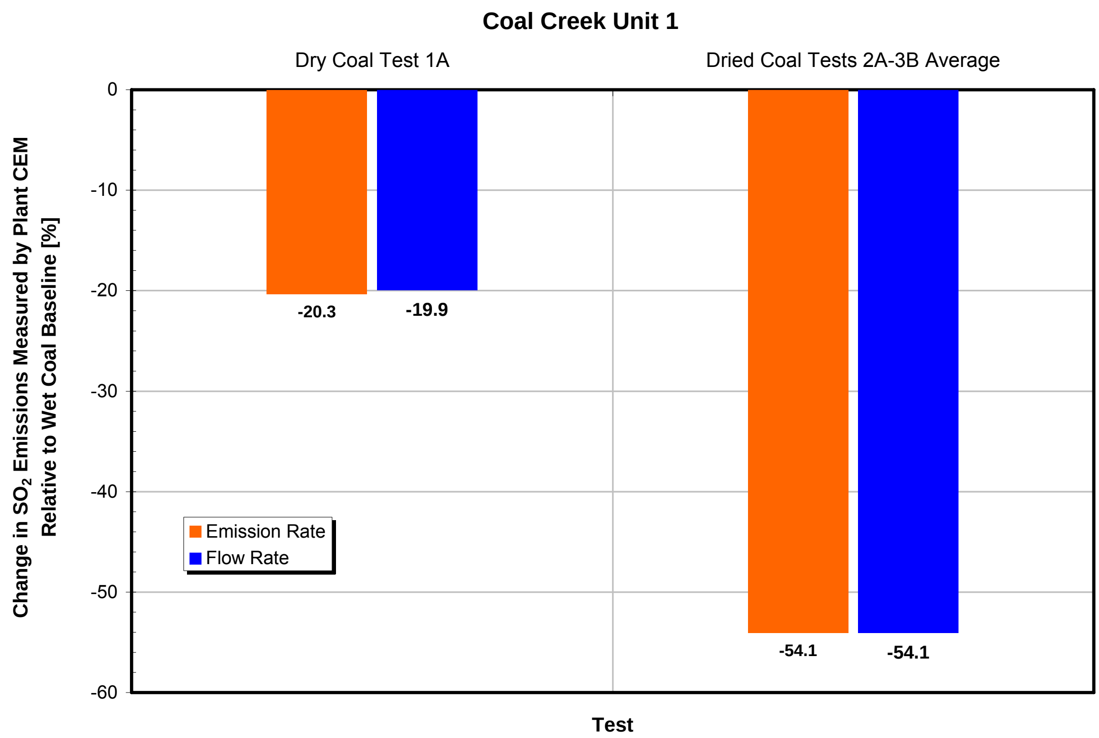

Figure 71: Reduction in Stack SO_2 Emissions Rate and Mass Emissions Relative to Wet Coal Baseline

Percent SO_2 removal, calculated from SO_2 concentration measured at the scrubber inlet and the stack for the wet coal baseline tests and preliminary tests with dried coal is presented in Figure 72. For baseline tests with wet coal pressure differential in the scrubber was set at 6.5 "wg, while for preliminary tests with dried coal due to lower volumetric flow of flue gas it was possible to increase scrubber pressure differential set point to 8.5" wg and scrub larger percentage of flue gas flow. For Test 1A, the scrubber pressure differential set point was 7.5" wg. Results show that for preliminary tests with dried coal, SO_2 removal increased by 12.3 percentage points (from 73.3 to 85.6 percent) compared to the wet coal baseline. This increase in SO_2 removal is attributed to higher percentage of total flue gas flow being scrubbed, which was possible due to 3.4 percent lower total mass flow rate of flue gas (see Figure 40 and Table 19) and 50°F lower flue gas temperature at the scrubber inlet, which resulted in 7.8 percent lower volumetric flow of flue gas (Table 19).

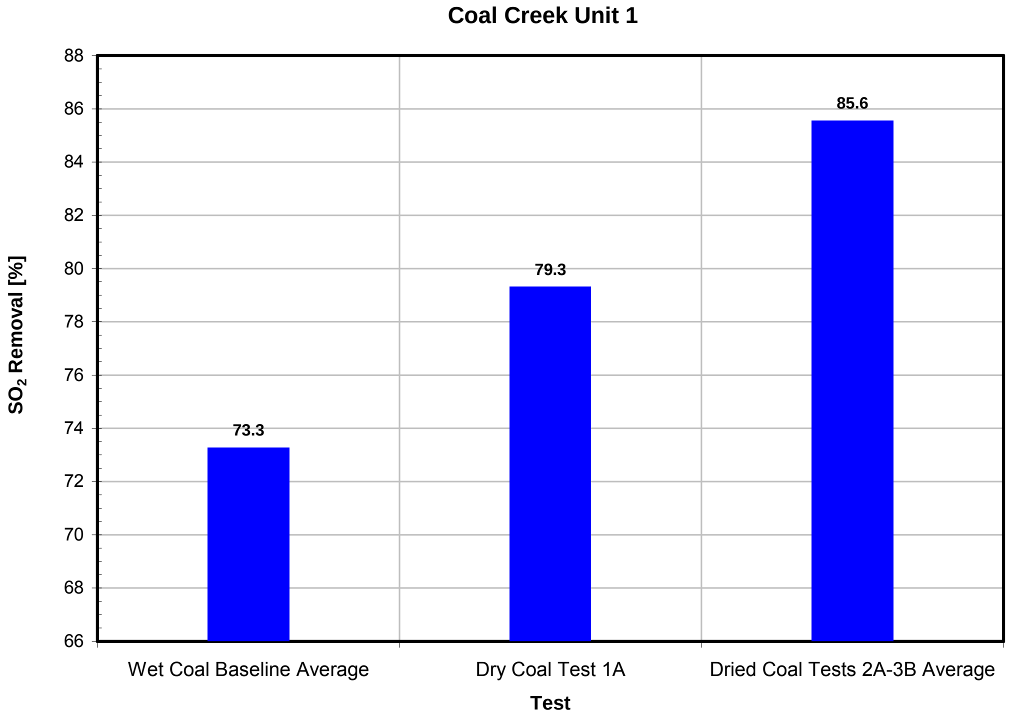

Figure 72: SO_2 Removal: Wet Coal Baseline vs. Preliminary Dried Coal Tests

8.3. CO_2 Emissions

CO_2 concentration in flue gas (on volume basis), measured by the plant CEM, for the wet coal baseline tests and preliminary tests with dried coal is compared in Figure 73. With dried coal measured CO_2 concentration was, on average, 0.47%-point higher compared to the wet coal baseline, see Figure 74. This is in part because with dried coal flue gas moisture content was, on average, 2.0%-points lower (see Figure 75) compared to the wet coal resulting in higher CO_2 concentration. Moisture content in flue gas was calculated using stoichiometry, coal composition, measured boiler exit O_2 level, APH air leakage rate, and humidity of primary and secondary air. CO_2 concentration in flue gas, expressed on weight basis, is presented in Figure 76. Results presented in Table 19 show that for dried coal CO_2 concentration expressed on weight basis was, on average, 0.68%-points higher compared to the wet coal baseline.

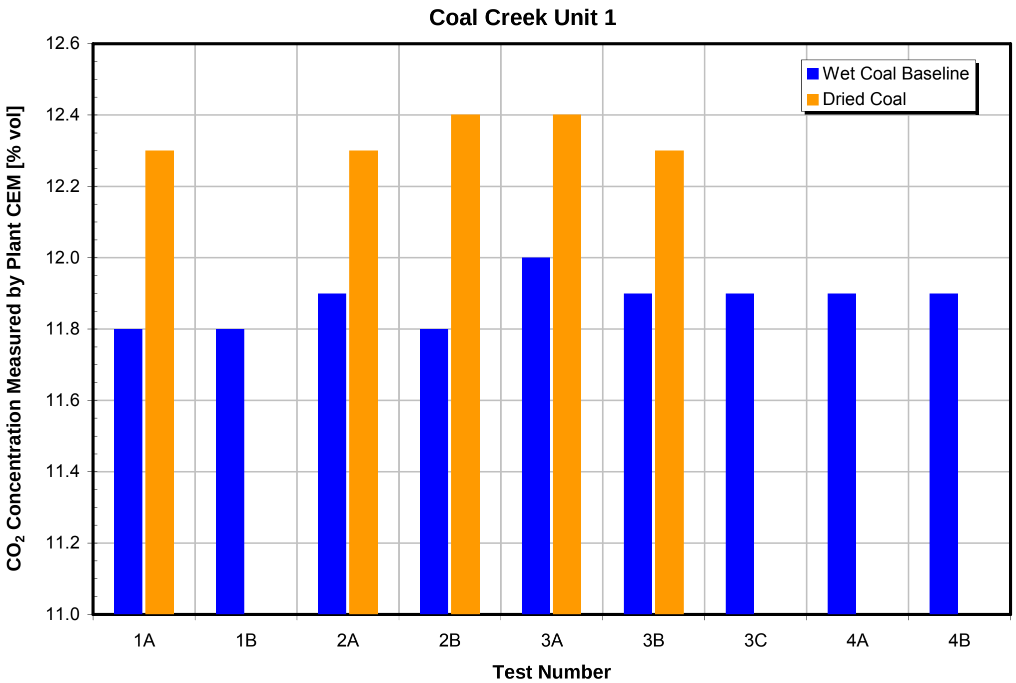

Figure 73: Measured CO_2 Concentration (volume basis): Wet Coal Baseline vs. Preliminary Dried Coal Tests

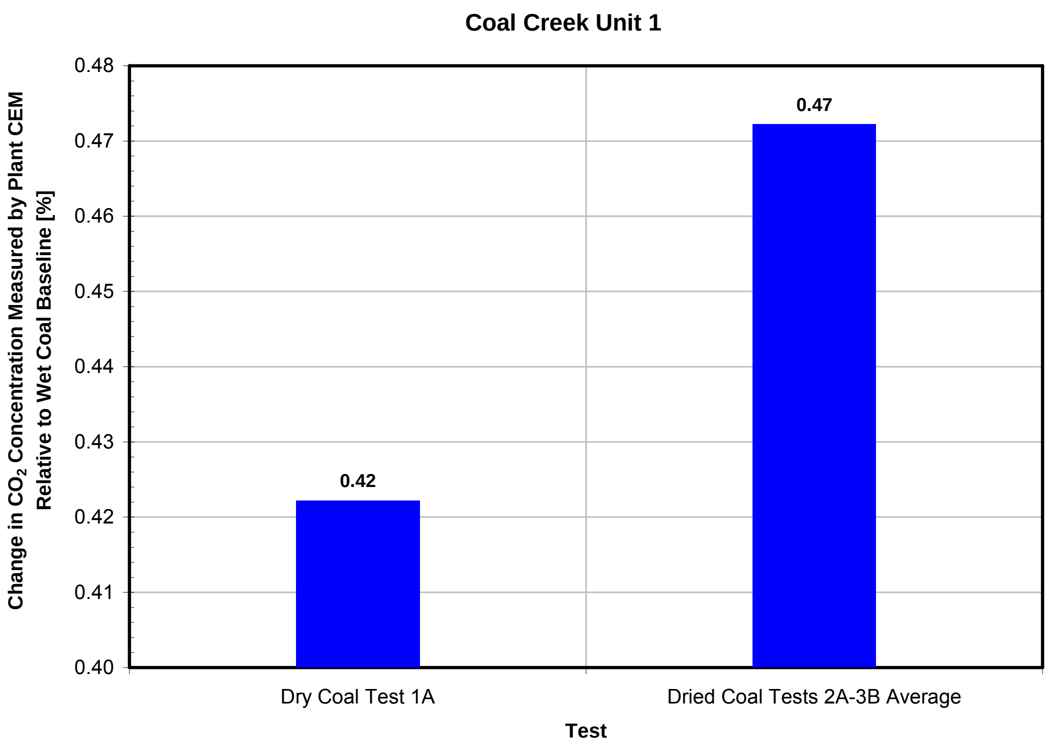

Figure 74: Change in CO_2 Concentration Measured by Plant CEM: Wet Coal Baseline vs. Preliminary Dried Coal Tests

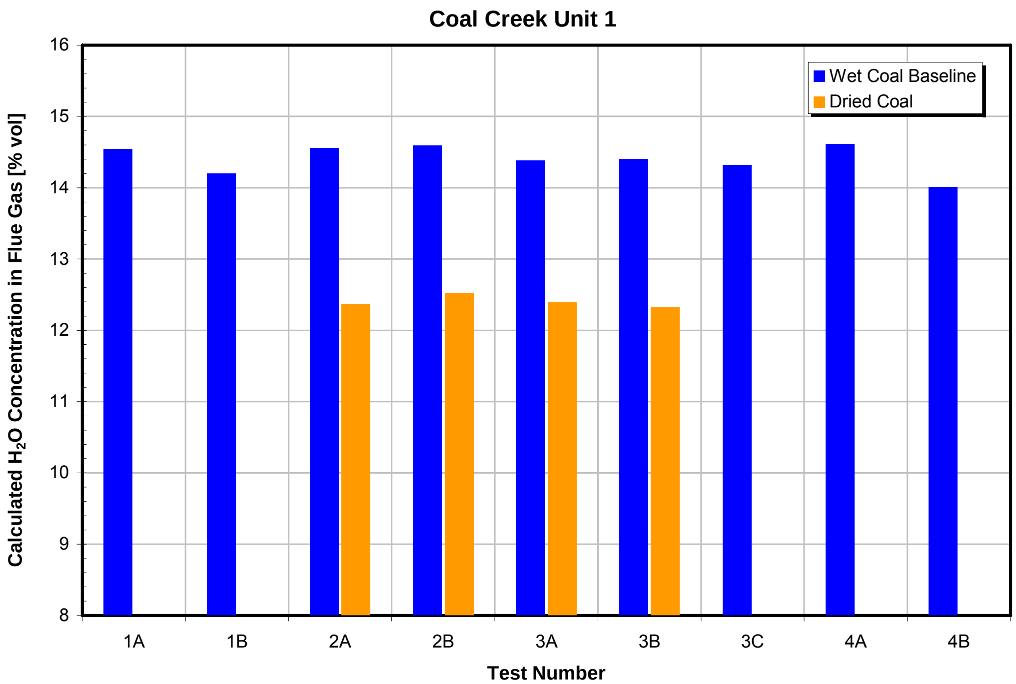

Figure 75: Calculated H_2O Concentration: Wet Coal Baseline vs. Preliminary Dried Coal Tests

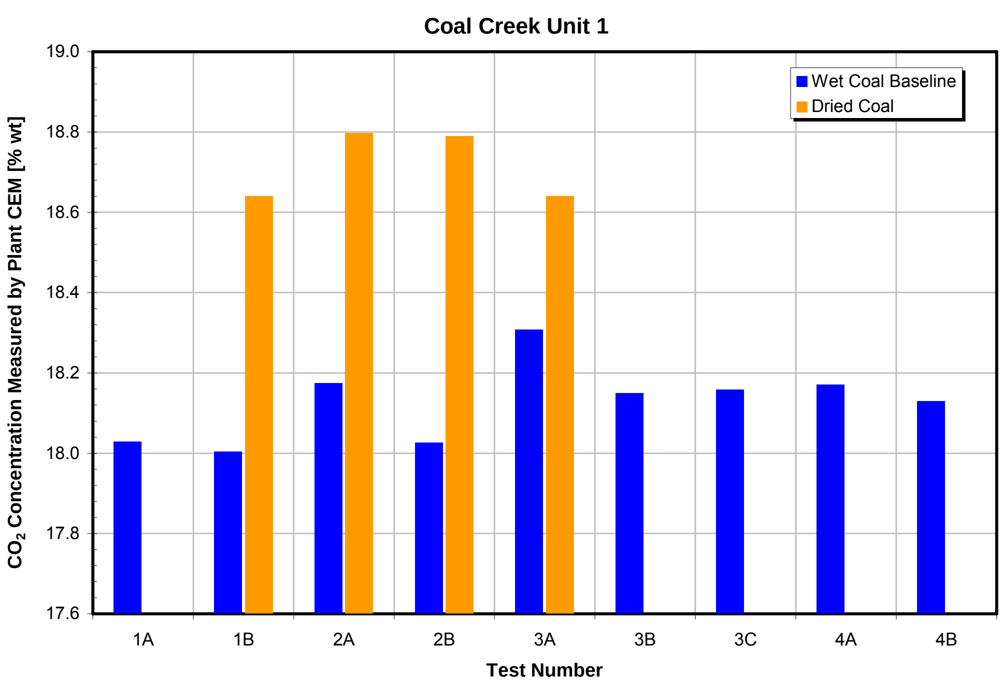

Figure 76: Measured CO_2 Concentration Expressed on Weight Basis: Wet Coal Baseline vs. Preliminary Dried Coal Tests

CO_2 mass emissions rates, calculated from Equation 14, reported by the plant CEM for wet coal baseline and preliminary dried coal tests are compared in Figure 77. The average CO_2 mass emissions rate for dried coal was 0.20%-point higher compared to the average value corresponding to the wet coal baseline, see Table 19.

$M_{CO2} = 5.7 \times 10^{-4} (CO_{2,Stack}) V_{Stack,STP}$ Eqn. 14

CO_2 mass emissions rates, calculated by using Equations 15 to 20, are presented in Figure 78 and Table 19. Results presented in Table 19 and Figure 79 show that CO_2 mass emissions with dried coal (616.0 t/hr) were, on average, 0.22 percent higher compared to the wet coal baseline (614.6 t/hr) and approximately 1.5 percent lower compared to values reported by the plant CEM.

$M_{CO2} = M_{Stack}\ CO_{2,Stack,wt}$ Eqn. 15

$M_{Stack} = V_{Stack}\ \rho_{Stack}$ Eqn. 16

$V_{Stack} = V_{Stack,STP}\ (T_{Stack}/T_{STD})\ (P_{STD}/P_{Stack})$ Eqn. 17

$\rho_{Stack} = P_{Stack}/(\boldsymbol{R}\ T_{Stack})$ Eqn. 18

$CO_{2,Stack,wt} = CO_{2,Stack,vol}\ 44/Mw_{Stack}$ Eqn. 19

$\boldsymbol{R} = R_{univ}/M_{wStack}$ Eqn. 20

<u>Where</u>:

V_{Stack}	Volumetric flow of flue gas measured by plant CEM [acfm]
T_{Stack}	Temperature of flue gas measured in the stack [^oF] or [K]
P_{Stack}	Pressure in the stack at CEM elevation [“wg] or [N/m^2]
$CO_{2,Stack,vol}$	Concentration of CO_2 in flue gas measured by plant CEM [% vol]
T_{STD}	Standard temperature [25 ^oC]
P_{STD}	Standard pressure [101,350 N/m^2]
M_{WStack}	Molecular weight of flue gas in the stack [kg/mole]
$V_{Stack,STP}$	Flow rate of flue gas in the stack at T_{STD} and P_{STD} [kscfh]

Table 19: Emissions: Wet Coal Baseline vs. Preliminary Dried Coal Tests

Parameter (Measured or Calculated at Stack)	Units	Wet Coal Baseline	Prelimary Dried Coal Tests	% Change Realtive to Wet Coal	Absolute Change Relative to Wet Coal
Flue gas molecular weight	kg/mole	28.8797	28.9437	**0.22**	0.06
Measured CO_2 concentration	% vol	**11.88**	**12.35**	**3.98**	**0.47**
Actual flue gas temperature (T_{actual})	°F	188	150		-37.8
	°C	86.43	65.44		-20.98
	K	359.58	338.59		-20.98
Gas constant	J/mole-K	287.88	287.25	**-0.22**	-0.64
Ambient Pressure ($P_{ambient}$)	"Hg	27.58	27.14		-0.44
	N/m^2	93,083	91,598		-1,485
Flue gas density	kg/m^3	0.8992	0.9418	**4.73**	0.0426
	lb/ft^3	0.05614	0.05880	**4.73**	0.0027
Standard pressure (P_{STD})	N/m^2	101,350	101,350		
Standard temperature (T_{STD})	°C	25	25		
	K	298.15	298.15		
CEM Heat input	MBtu/hr	5,694	5,525	**-2.97**	-169
CEM Flue gas flow rate	kscfm	1,536	1,480	**-3.62**	-56
NO_x Mass Emissions	lb/hr	1,615	1,069	**-33.81**	-546
SO_2 Mass Emissions	lb/hr	3,315	1,522	**-54.10**	-1,793
$(T_{STD}/T_{actual})(P_{ambient}/P_{STD})$		0.762	0.796		
Flue gas flow rate	kacfm	2,017	1,860	**-7.77**	-156.7
	klbs/hr	6,793	6,562	**-3.40**	-231.1
Stack CO_2 concentration	% wt	18.10	18.77	**3.75**	**0.68**
Calculated CO_2 Mass Emissions	klb/hr	1,229	1,232	**0.22**	2.66
	t/hr	614.6	616.0	**0.22**	1.33
CEM CO_2 Mass emissions	t/hr	624.3	625.5	**0.20**	1.23
CO_2 Emissions rate	lb/MBtu	0.216	0.223	**3.29**	0.01

Equation 14 and Equations 15 to 20 illustrate that the calculated value of CO_2 mass emissions is critically dependent on flow rate of flue gas and CO_2 concentration measured by the plant CEM. As discussed above, annual RATA test was performed before September 2009 wet coal baseline tests and plant CEM monitor. It is therefore reasonable to assume that flue gas flow rate and CO_2 concentration, measured in September 2009 tests, were as accurate as possible under field conditions.

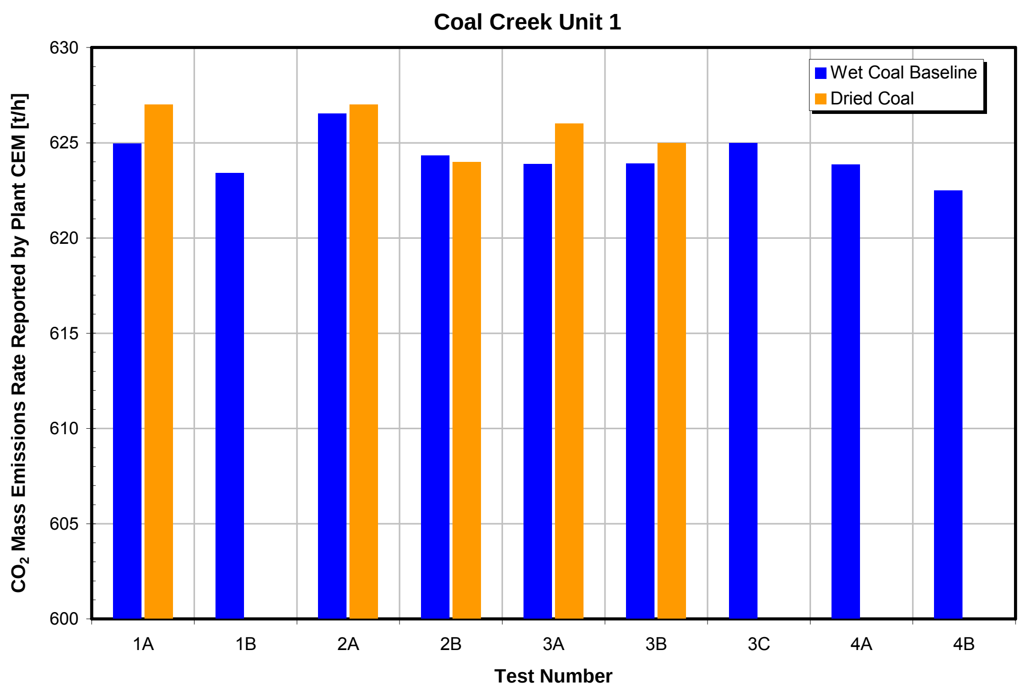

Figure 77: CO_2 Mass Emissions Rate Reported by Plant CEM: Wet Coal Baseline vs. Preliminary Dried Coal Tests

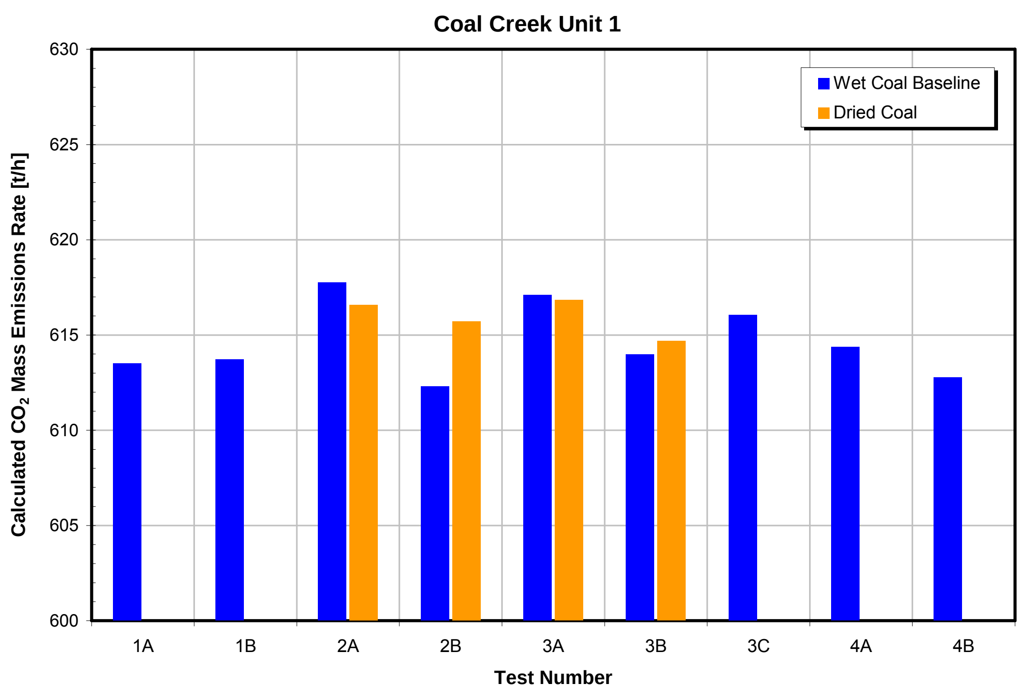

Figure 78: Calculated CO_2 Mass Emissions Rate: Wet Coal Baseline vs. Preliminary Dried Coal Tests

Preliminary tests with dried coal were conducted in March/April 2010, approximately eight months after annual RATA. Therefore, measured values of flue gas flow rate and CO_2 concentration could have been affected by instrument drift. This makes accurate measurement of small changes in CO_2 mass emissions a difficult task.

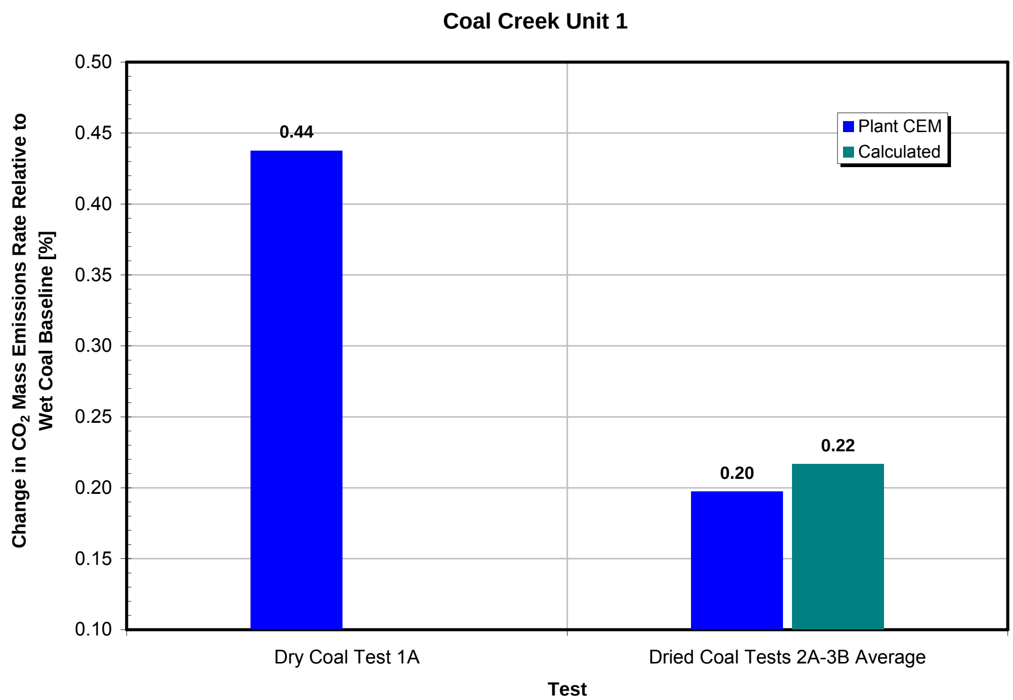

Figure 79: Change in CO_2 Mass Emission Rate: Wet Coal Baseline vs. Preliminary Dried Coal Tests

Other measured parameters affecting the accuracy of CO_2 mass emissions rate include stack pressure and temperature, ultimate coal composition, excess O_2 level at boiler and APH exit (or scrubber inlet). Any error in measurement of these quantities will propagate into error in CO_2 mass emissions rate.

Results presented in Figures 77 to 79 and Table 19 show that with dried coal CO_2 mass emissions were marginally higher compared to the wet coal baseline. This is unexpected because CO_2 emissions were expected to decrease with dried coal due to improvement in unit performance.

As discussed in Section 7.4 (Unit Performance), during wet coal baseline tests conducted in September 2009, turbine cycle was isolated by switching auxiliary steam extractions to Unit 2 while testing was performed on Unit 1, and vice versa. However, during preliminary tests with dried coal conducted in March/April 2010 Unit 2 was in outage so Unit 1 (test unit) was carrying all station loads in addition to providing auxiliary steam extractions. As a consequence, Unit 1 gross power output was approximately 13 MW lower and service load was higher compared to the September 2009 baseline test. Baseline tests with dried coal are planned for fall 2010 with both units at Coal Creek being in service so auxiliary steam extractions from turbine cycle could be moved to Unit 2.

Also, composition of raw, wet lignite burned during wet coal baseline tests conducted in September 2009 and during preliminary tests with dried coal conducted in March/April 2010 was different. Comparison of as-received coal carbon content is presented in Figure 80 as function of as-received HHV. Historic data are also shown. Data show that carbon content in raw coal received during preliminary tests conducted with dried coal in March/April 2010 was approximately 0.8%-point higher compared to the September 2009 wet coal baseline tests. This, higher coal carbon content, resulted in higher CO_2 concentration measured by the plant CEM during preliminary tests with dried coal.

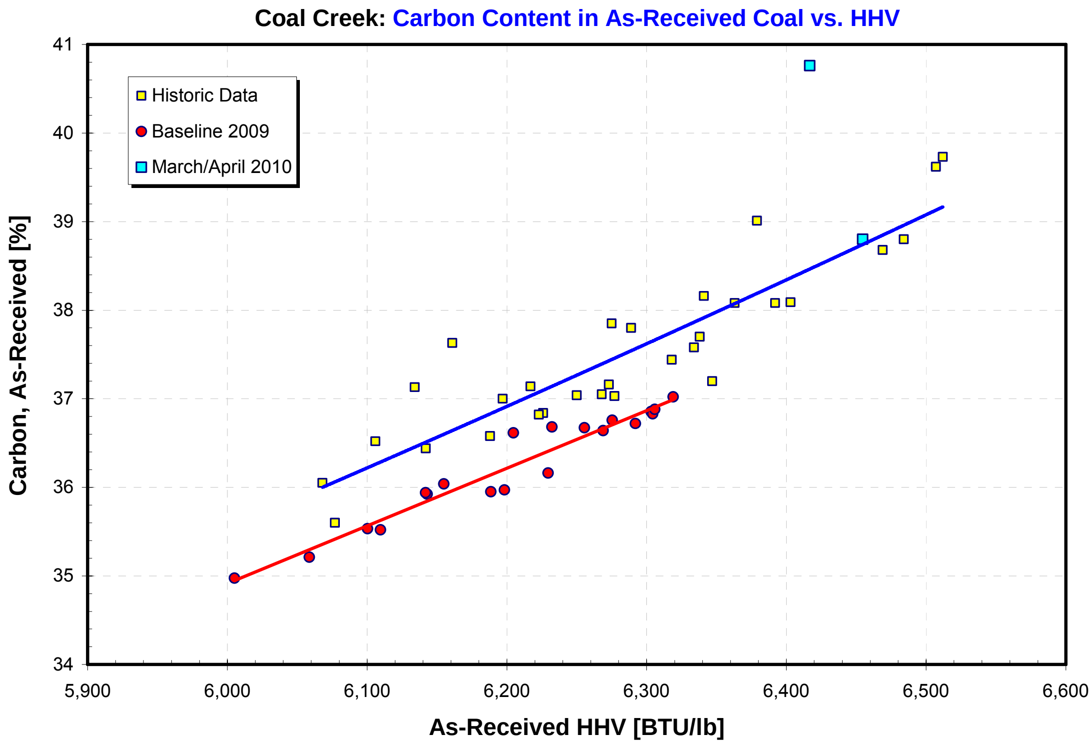

Figure 80: As-received Carbon in Coal: Wet Coal Baseline

In an alternative approach to determine the change in CO_2 emissions, the CO_2 concentration in flue gas at the stack was calculated using stoichiometry, information on coal composition received from a commercial analytical laboratory, excess O_2 level measured at the economizer exit and APH exit (or scrubber inlet), and humidity of ambient air. The CO_2 mass emissions rate was calculated using the calculated CO_2 concentration, and flue gas flow rate, stack temperature and pressure measured by the CEM monitor. Results, summarized in Table 20, show that calculated values of CO_2 concentration in the stack are by 0.7 to 1.2%-point higher compared to measured values presented in Table 19.

This difference in CO_2 concentration could be due to uncertainty in coal composition (either due to sampling or analysis), errors in measurement of excess O_2 (which propagate into error in calculated value of the APH air leakage), and errors in CO_2 concentration measured by the plant CEM. The calculated value of CO_2 mass emissions for preliminary tests with dried coal is approximately 3.8 percent lower compared to the wet coal baseline tests. Please note that mass emissions are proportional to the measured value of flue gas flow; any error in measurement of this quantity will have a direct effect on CO_2 mass emissions.

Table 20: Emissions: Calculated CO_2 Concentration

Parameter (Measured or Calculated at Stack)	**Units**	**Wet Coal Baseline**	**Prelimary Dried Coal Tests**	**% Change Realtive to Wet Coal**	**Absolute Change Relative to Wet Coal**
Flue gas molecular weight	kg/mole	28.8797	28.9437	**0.22**	0.06
Calculated CO_2 concentration	% vol	**13.06**	**13.04**	**-0.17**	**-0.02**
Actual flue gas temperature (T_{actual})	°F	188	150		-37.8
	°C	86.43	65.44		-20.98
	K	359.58	338.59		-20.98
Gas constant	J/mole-K	287.88	287.25	**-0.22**	-0.64
Ambient Pressure ($P_{ambient}$)	"Hg	27.58	27.14		-0.44
	N/m^2	93,083	91,598		-1,485
Flue gas density	kg/m^3	0.8992	0.9418	**4.73**	0.0426
	lb/ft^3	0.05614	0.05880	**4.73**	0.0027
Standard pressure (P_{STD})	N/m^2	101,350	101,350		
Standard temperature (T_{STD})	°C	25	25		
	K	298.15	298.15		
CEM Heat input	MBtu/hr	5,694	5,525	**-2.97**	-169
CEM Flue gas flow rate	kscfm	1,536	1,480	**-3.62**	-56
NO_x Mass Emissions	lb/hr	1,615	1,069	**-33.81**	-546
SO_2 Mass Emissions	lb/hr	3,315	1,522	**-54.10**	-1,793
$(T_{STD}/T_{actual})(P_{ambient}/P_{STD})$		0.762	0.796		
Flue gas flow rate	kacfm	2,017	1,860	**-7.77**	-156.7
	klbs/hr	6,793	6,562	**-3.40**	-231.1
Stack CO_2 concentration	% wt	19.90	19.82	**-0.39**	**-0.08**
Calculated CO_2 Mass Emissions	klb/hr	1,352	1,301	**-3.78**	-51.09
	t/hr	675.9	650.4	**-3.78**	-25.55
CEM CO_2 Mass emissions	t/hr	624.3	625.5	**0.20**	1.23
CO_2 Emissions rate	lb/MBtu	0.237	0.235	**-0.83**	0.00

Corrections for difference in coal composition on emissions (and performance) are needed for accurate comparison of CO_2 emissions (and performance).

As an alternative to direct measurement, flow rate of coal and flue gas, CO_2 concentration in the flue gas, and CO_2 mass emissions can be calculated from the mass and energy balance for the unit. This approach requires accurate information on coal composition and HHV, excess O_2 level, air preheater and ESP air in-leakage rates, and turbine cycle performance.

CO_2 emissions can also be presented as CO_2 percentage in flue gas (on weight basis) divided by percent carbon content in coal. For wet coal baseline the result is 0.484 %CO_2/%C in coal. For dried coal the value of this parameter is 0.471 %CO_2/%C in coal, approximately 2.5 percent lower.

8.4. Mercury Emissions

Flue gas mercury concentration and speciation were measured during wet coal baseline tests and preliminary tests with dried coal using sCEMs and sorbent traps as discussed in Section 6 of the report. Test matrices for wet coal baseline and preliminary test wet dried coal are summarized in Tables 7 and 9, respectively and in Table 21.

Table 21: Mercury measurement locations and equipment

Location	Wet Coal Baseline	Preliminary Tests with Dried Coal
Coal Dryer Exhaust		Sorbent Trap
APH Inlet	sCEM	sCEM
FGD Inlet	sCEM, Sorbent Trap	sCEM
FGD Bypass	sCEM	sCEM, Sorbent Trap
FGD Outlet	sCEM, Sorbent Trap	sCEM, Sorbent Trap
Stack	Sorbent Trap	sCEM

Solid samples were taken from the raw (wet) coal stream entering the unit (CS2), mill (pulverizer) rejects (manual sample), economizer ash (manual sample), bottom ash (manual sample), and fly ash (manual sample). With coal drying system in operation, coal samples were also taken from the segregated coal stream (conveyor 266, air jig inlet), cleaned coal (conveyor 269, air jig outlet), conveyors 961/962 and dried coal (coal dryer) feeders (product stream), and scrubber limestone feed. Sampling points are presented in Figure 20. Also, liquid samples were taken from the scrubber blowdown liquor and make-up.

Mercury in Coal and Ash

Coal samples, including pulverizer rejects, were analyzed for composition, ash mineral content, and mercury. In addition, raw coal samples and coal samples collected at feeder inlet were analyzed for chlorine. Ash samples were analyzed for mineral content and mercury.

The mercury concentration in coal samples taken at various state points during March/April 2010 preliminary tests with dried coal, relative to the Hg concentration in as-received (raw) coal is presented in Figure 81. Results show that Hg concentration in the segregation stream was significantly (by a factor of two) higher compared to the raw coal (feed). After cleaning in the air jig, mercury content in the clean segregated stream (cleaned segregated coal) was reduced to almost half of the raw coal. Mercury content measured at the mill feeder inlet (after mixing of product and segregated streams) was approximately 70 percent of the raw coal.

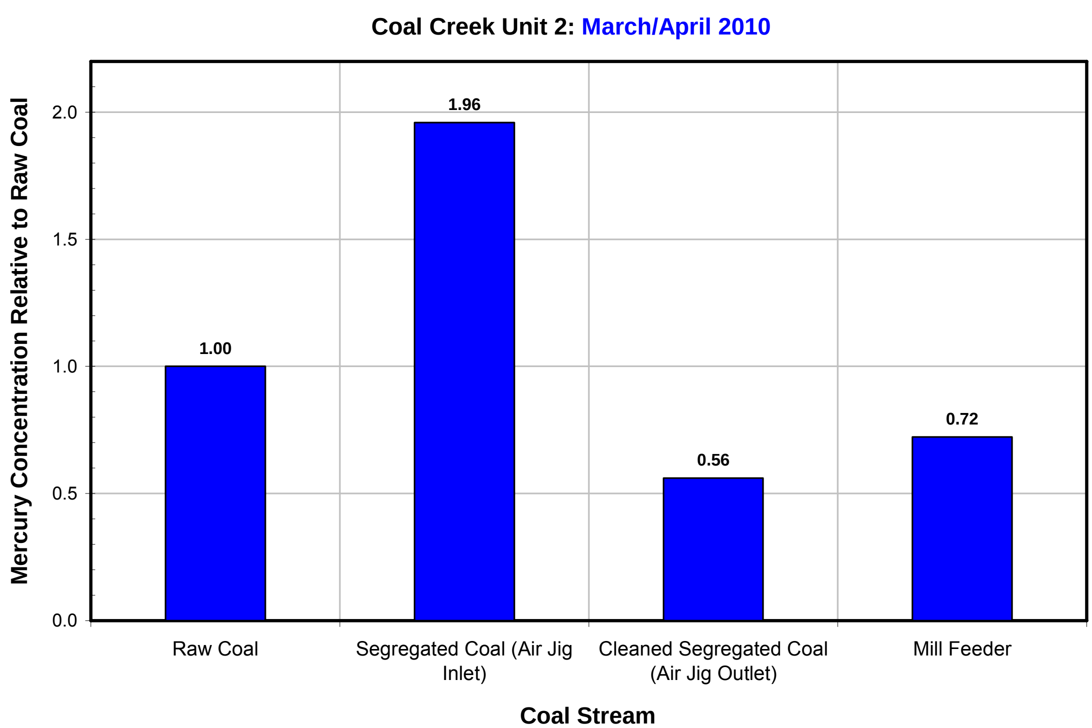

Figure 81: Mercury Content in Coal Samples Collected at Various Locations: Preliminary Tests with Dried Coal

Mercury content in ash was low, lower than 0.001 μg/g (0.001 ppm). Pulverizer rejects were high in sulfur (average 13 percent) and mercury (average

0.988 ppm or 988 ppb), where mercury was most likely included in pyrite. Although the concentration of mercury in pulverizer rejects was more than two orders of magnitude higher than in the coal, pulverizer rejects represented only 0.02 to 0.03 percent of the raw coal flow.

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

<u>Mercury in Flue Gas</u>

The plant Hg monitor was calibrated in October 2009 and since then it is providing continuous measurement of total and elemental mercury concentration in the stack. Therefore, no Hg CEM data is available for comparison with the sCEM and sorbent trap measurements conducted during baseline tests with wet coal.

Vapor-phase mercury concentration in the flue gas, measured by sCEMs at the APH inlet, scrubber (FGD) inlet and outlet, and scrubber bypass is presented in Figures 82 to 88. Solid symbols represent measured values of total mercury (Hg^T), while measured values of elemental mercury (Hg^0) are indicated by open symbols. Mercury measurements conducted during the wet coal baseline tests are presented in Figures 82 to 85. Total mercury concentration measured by the sCEMs and plant Hg CEM during preliminary tests with dried coal, given in Figures 86 to 88, shows relatively good agreement in Hg^T measured by the sCEM at the FGD outlet and Hg^T measured by the plant Hg CEM. Due to higher Hg^T concentration in the FGD bypass stream compared to the FGD outlet, Hg^T concentration measured in the stack should be higher compared to the FGD outlet.

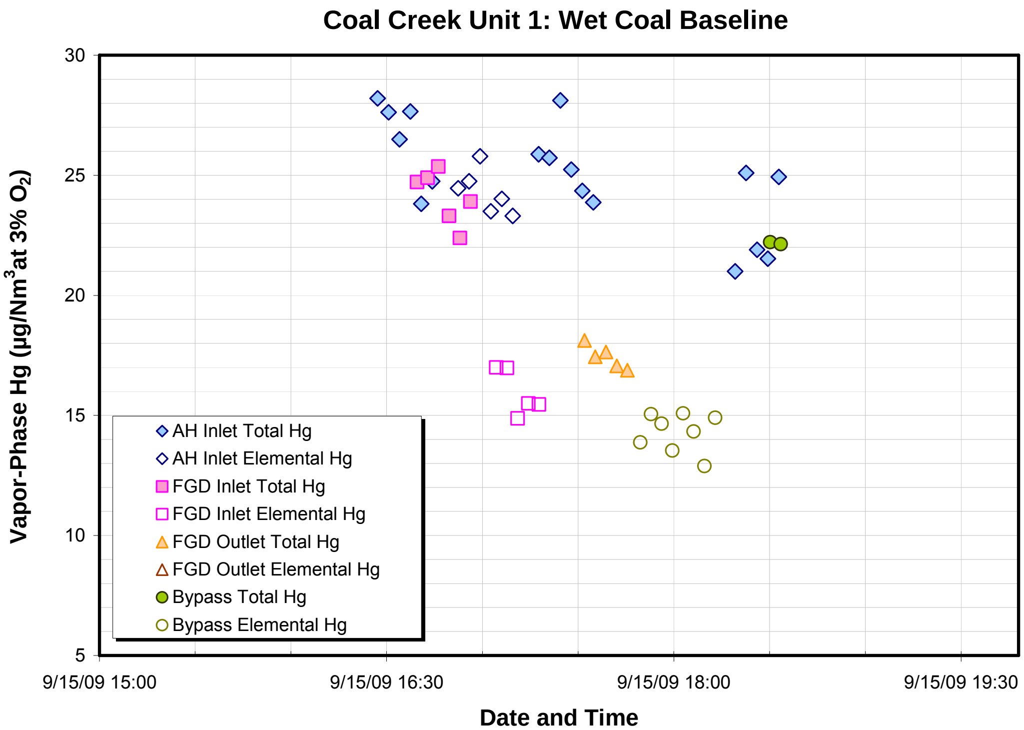

Figure 82: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on September 15, 2009 (Wet Coal Baseline)

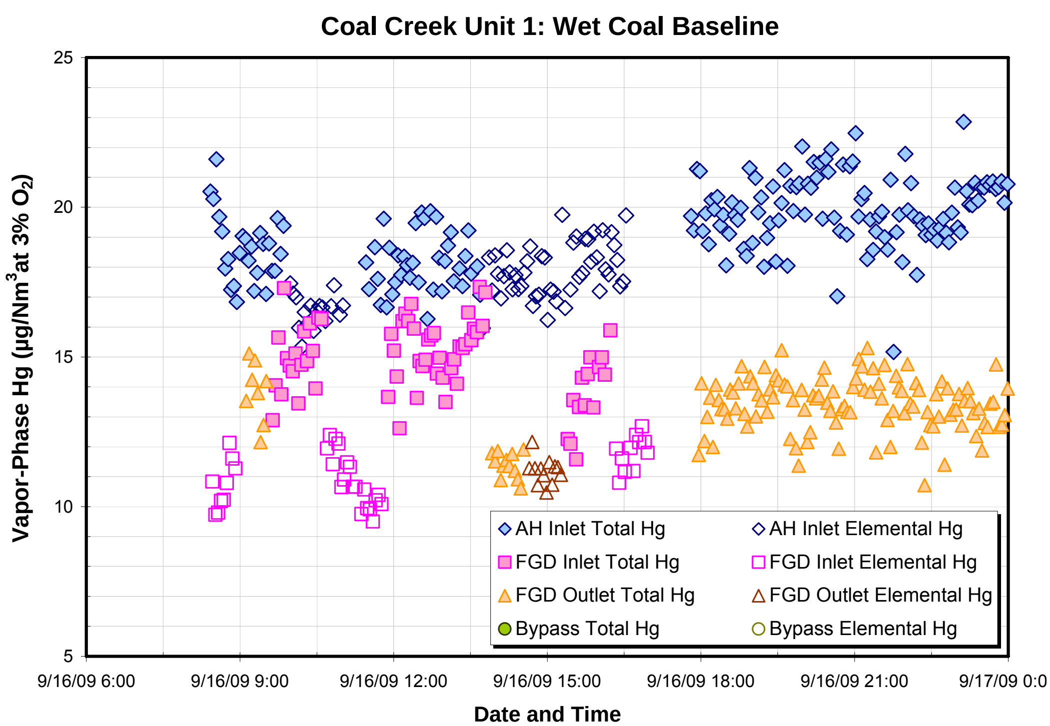

Figure 83: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on September 16, 2009 (Wet Coal Baseline)

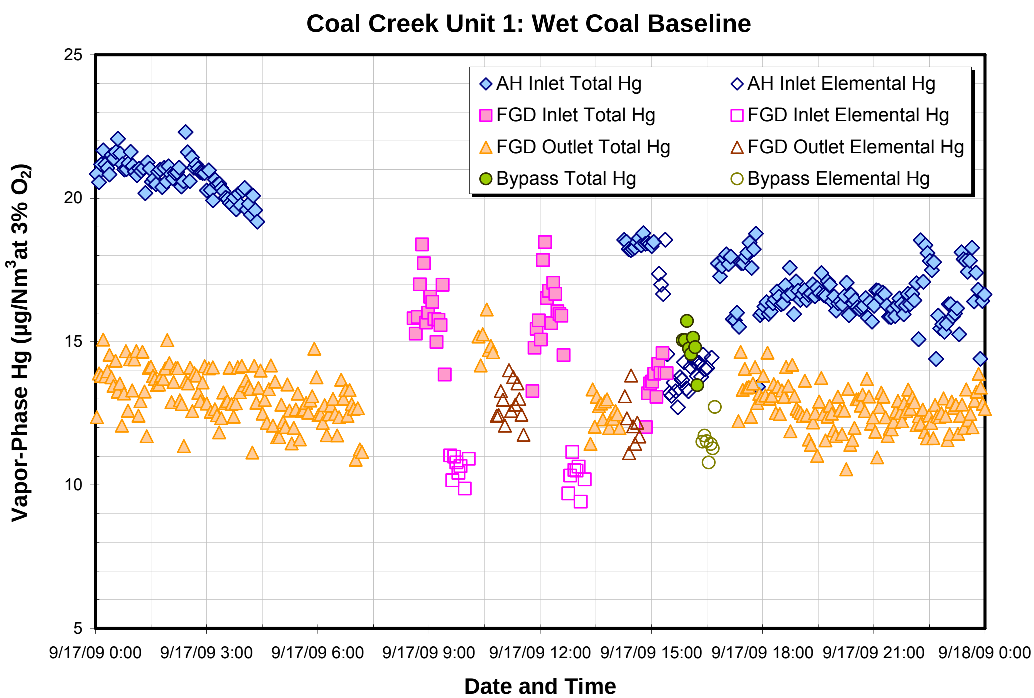

Figure 84: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on September 17, 2009 (Wet Coal Baseline)

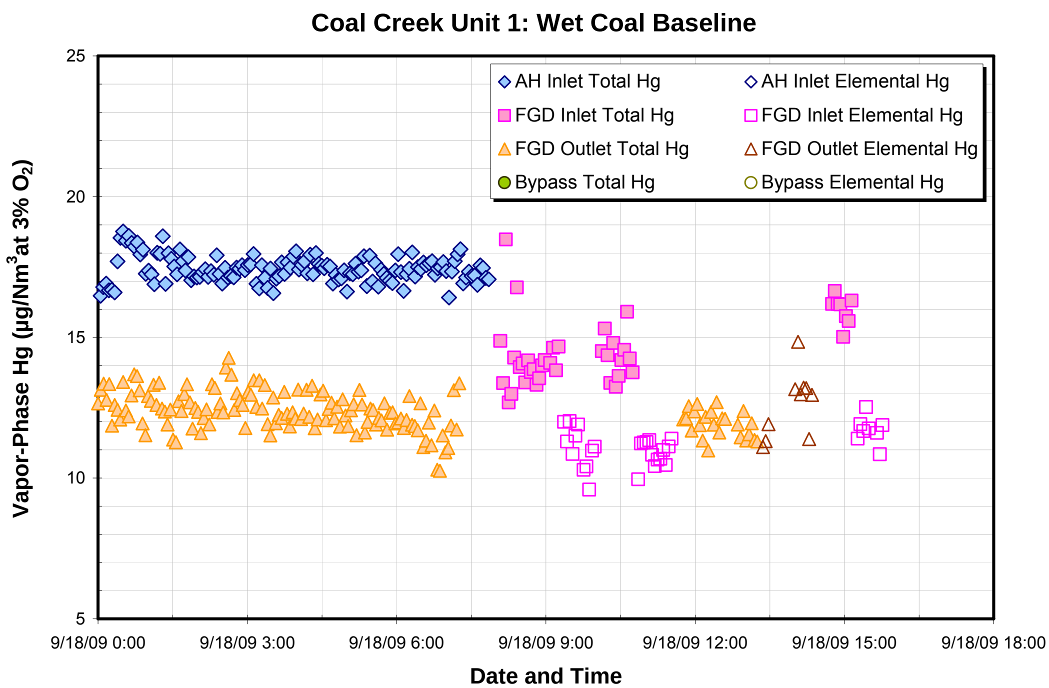

Figure 85: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on September 18, 2009 (Wet Coal Baseline)

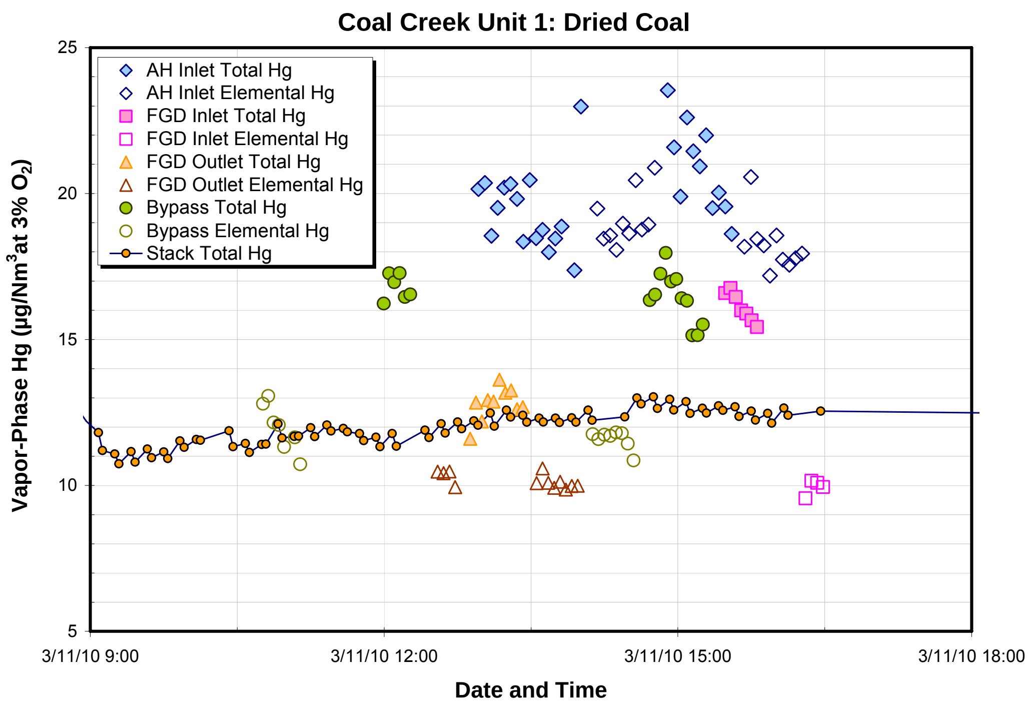

Figure 86: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on March 11, 2010 (Preliminary Tests with Dried Coal)

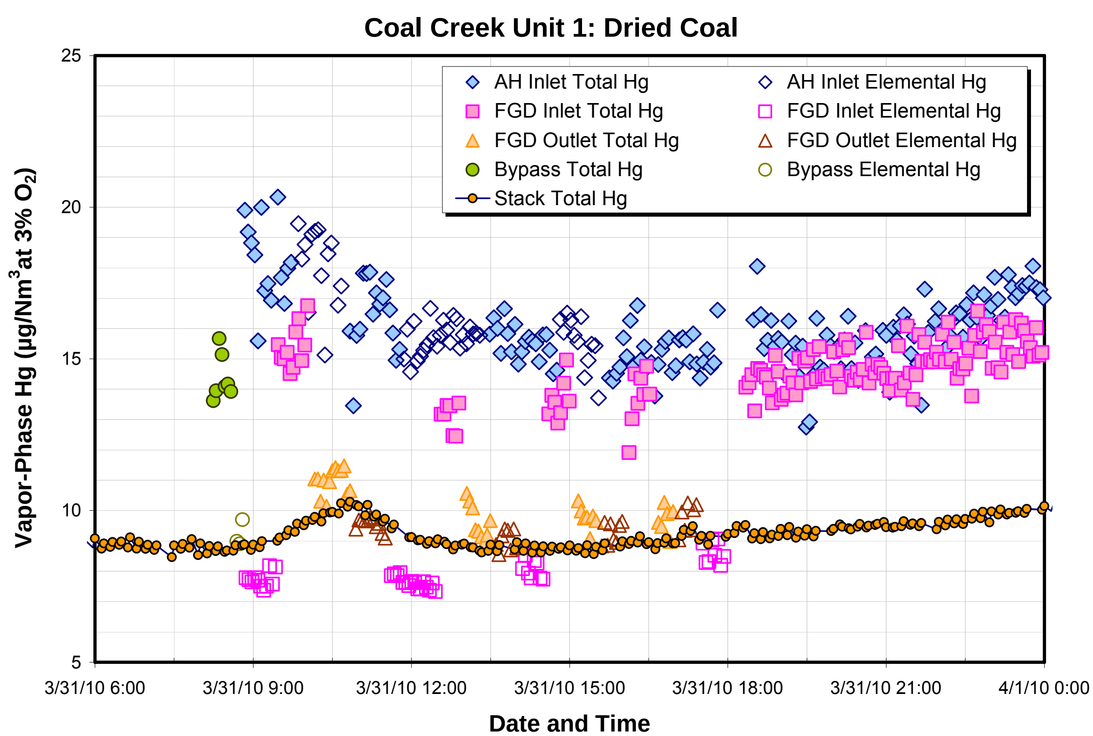

Figure 87: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on March 31, 2010 (Preliminary Tests with Dried Coal)

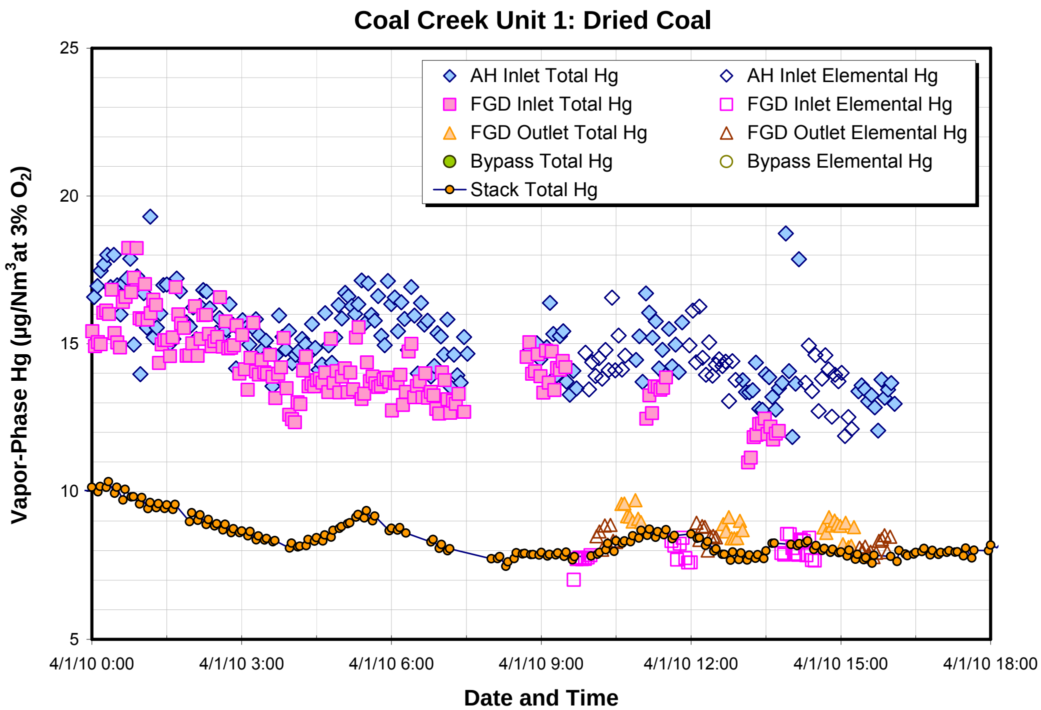

Figure 88: Vapor-phase Hg Concentration in Flue Gas Measured by sCEMs on April 1, 2010 (Preliminary Tests with Dried Coal)

Mercury concentration values (Hg^T and Hg^o), measured by the sCEMs at the APH inlet, FGD inlet and outlet, and FGD bypass and the plant Hg monitor (stack), are summarized in Table 22. Native mercury removal across the APH, ESP and FGD, across the FGD, and across the APH, ESP, and FGD for wet coal baseline tests and preliminary tests conducted with dried coal is presented in Table 23. Changes in total, elemental, and oxidized mercury measured by the sCEMs for wet and dried coal tests are presented in Figures 89 to 91.

Results presented in Table 22 and Figure 89 show that with dried coal, average total mercury (Hg^T) concentration at the boiler outlet (APH inlet) decreased from 19.2 to 15.3 $\mu g/Nm^3$ (approximately 20 percent), relative to the wet coal baseline. At that location most of the mercury is Hg^0, which is typical for low chlorine coals. Assuming a consistent Hg level in the raw lignite used in wet coal baseline test and preliminary test with dried coal, this reduction in Hg^T may be the result of reduced carbon monoxide (CO) emissions in the furnace and boiler convective pass (CO has been recognized to increase Hg emissions in the flue gas). Lower CO emissions occur at reduced flue gas moisture levels.

Also, with dried coal, average Hg^T concentration at the wet scrubber (FGD) inlet, downstream of the electrostatic precipitator (ESP), decreased from 16 to 13.7 $\mu g/Nm^3$ (approximately 14 percent), relative to the wet coal. As presented in Table 22 and Figure 89, Hg speciation (oxidized mercury/total mercury, Hg^{2+}/Hg^T) at the FGD inlet increased from 27 to 42 percent (see Figure 91). The reduction in Hg^T concentration and the added benefit of Hg oxidation (which promotes additional Hg capture in the FGD, Hg^{2+} being a water-soluble species) is most likely of a direct result of reduced volumetric flow rate of flue gas (increased residence time), and flue gas temperatures (faster quenching of the flue gas) under dried coal conditions. These have been found to promote Hg oxidation and capture onto fly ash, in-flight and at the ESP.

Also, with dried coal the average Hg^T concentration at the FGD outlet decreased from 13.1 to 9.5 $\mu g/Nm^3$ (approximately 27 percent), see Figure 89, relative to the wet coal. This corresponds to increase in native Hg^T removal across the FGD from 15 to 35 percent (see Table 23). As expected, the FGD removed most of the Hg^{2+} from the flue gas, reducing its concentration from 27 to 7 percent for the wet coal, and from 42 to 6 percent for the dried coal (see Figure 91). As presented in Table 23, this corresponds to an increase in native removal of Hg^{2+} across the FGD from 74 to 86 percent. Total native Hg^T removal for dried coal, measured by the sCEMs, was 38 percent, approximately 23 percent higher compared to wet coal.

Re-emission of Hg^0 was reduced from 33 percent for wet coal to 17 percent for dried coal (see Table 23) further reducing Hg emissions. Therefore, with dried coal, smaller amount of additive for Hg^0 retention in the FGD liquor would be needed to control re-emissions of Hg^0.

Table 22: Measured Vapor-Phase Mercury Concentration at Various State Points: Wet Coal Baseline and Preliminary Tests with Dried Coal

sCEM Measurements				
Measurement Location	**Measured Quantity (sCEM)**	**Units**	**Wet Coal Baseline Average**	**Dried Coal Average**
APH Inlet	Total Hg	$\mu g/dNm^3$ at 3% O_2	**19.2**	**15.3**
	Elemental Hg	$\mu g/dNm^3$ at 3% O_2	18.0	15.3
	Oxidized Hg	% of Hg^T	**11**	**1**
FGD Inlet	Total Hg	$\mu g/dNm^3$ at 3% O_2	**16.0**	**13.7**
	Elemental Hg	$\mu g/dNm^3$ at 3% O_2	11.6	8.0
	Oxidized Hg	% of Hg^T	27	42
FGD Outlet	Total Hg	$\mu g/dNm^3$ at 3% O_2	**13.1**	**9.5**
	Elemental Hg	$\mu g/dNm^3$ at 3% O_2	12.3	8.9
	Oxidized Hg	%	**7**	**6**
FGD Bypass	Total Hg	$\mu g/dNm^3$ at 3% O_2	**14.82**	**14.40**
	Elemental Hg	$\mu g/dNm^3$ at 3% O_2	11.57	9.70
	Oxidized Hg	% of Hg^T	22	33
Stack	Total Hg	$\mu g/dNm^3$ at 3% O_2		**8.7**
	Elemental Hg	$\mu g/dNm^3$ at 3% O_2		8.3
	Oxidized Hg	% of Hg^T		**5**

Table 23: Native Mercury Removal at Various State Points: Wet Coal Baseline and Preliminary Tests with Dried Coal

Native Mercury Removal	Wet Coal Baseline Average	Dried Coal Average
	%	%
Native Hg^T Removal Across APH/ESP	**16**	**10**
Native Hg^T Removal Across FGD	**15**	**35**
Native Hg^T Removal Across APH/ESP/FGD	**31**	**38**
Native Hg^{2+} Removal Across FGD	**74**	**86**
Hg^{2+} Re-emitted as Hg^0	**33**	**17**

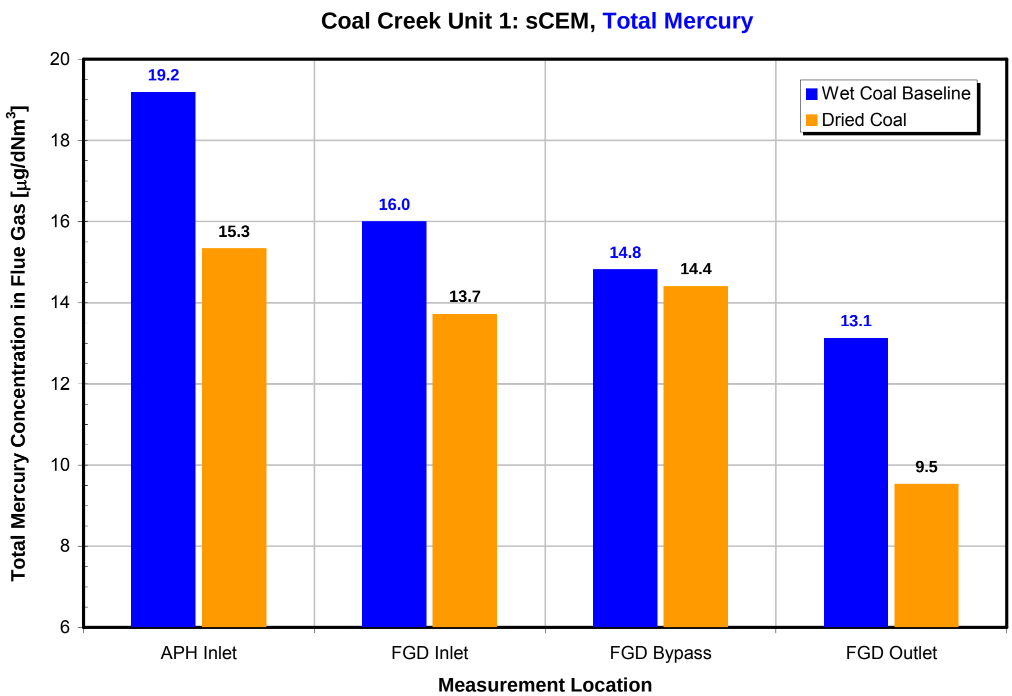

Figure 89: Total Mercury Measured by sCEM at Various State Points

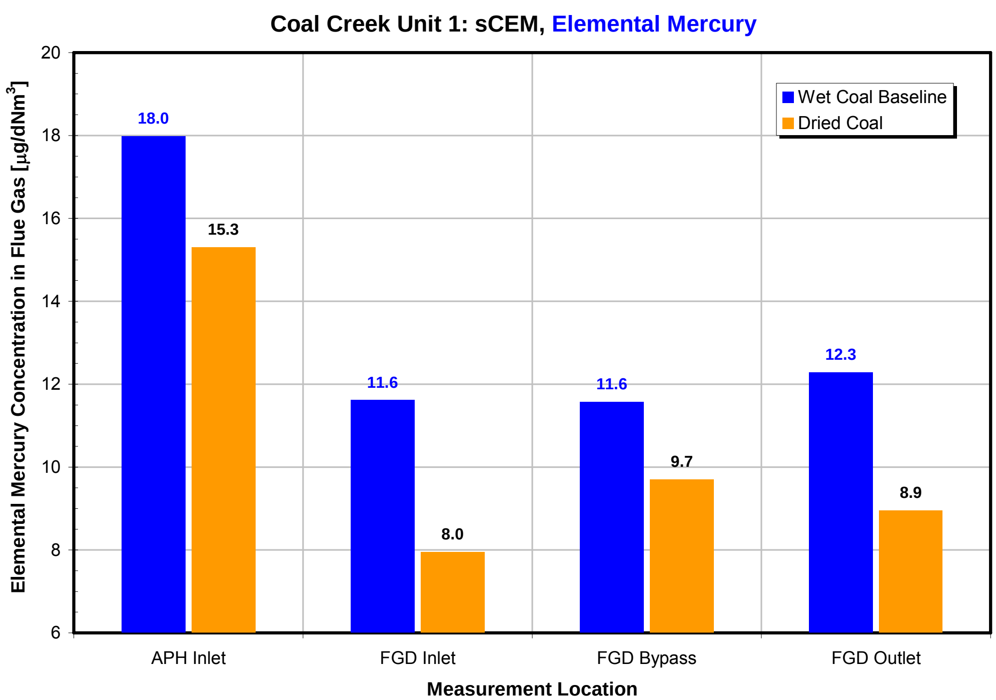

Figure 90: Elemental Mercury Measured by sCEM at Various State Points

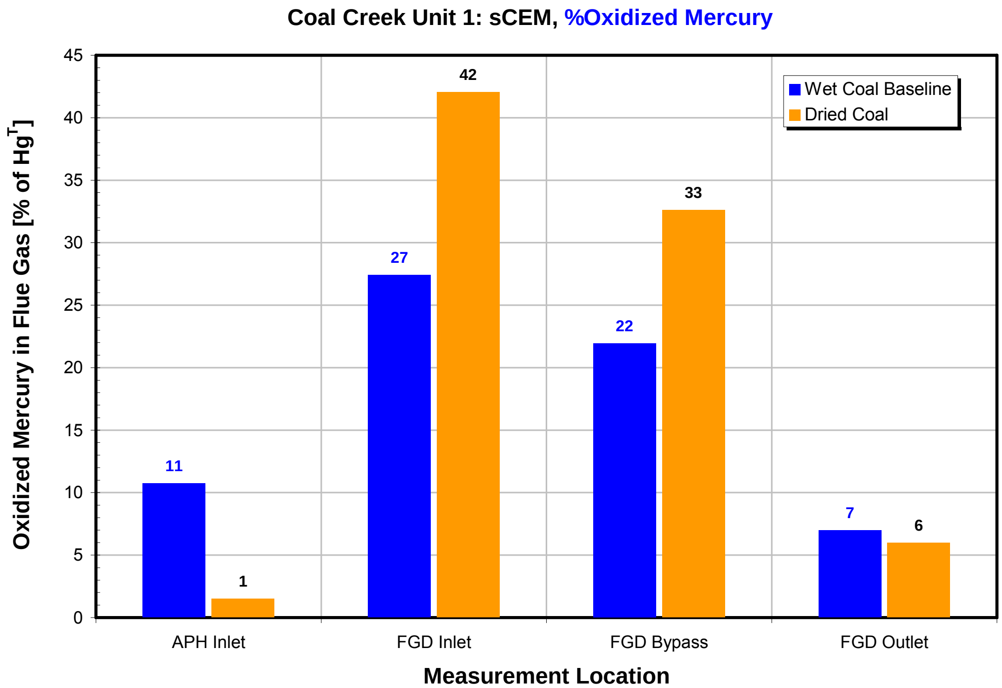

Figure 91: Oxidized Mercury Measured by sCEM at Various State Points

The results on mercury concentration and speciation presented above were obtained by using sCEMs. To check accuracy of mercury measurements, standard EPA-approved methods are used. Non-speciating sorbent traps were used during wet coal baseline tests and preliminary tests performed with dried coal to determine actual mercury concentration. Modified Appendix K method was used. Quality control and assurance were performed according to EPA requirements.

Total mercury concentration in flue gas measured by sorbent traps at different state points is summarized in Table 24. The results show that with dried coal the reduction in Hg^T concentration, measured at the FGD outlet, relative to wet coal, was almost 44 percent (43.7%).

Table 24: Total Mercury Measured by Sorbent Traps

Total Mercury Measured by Sorbent Traps			
Location	**Wet Coal Baseline Average**	**Dried Coal Average**	**Difference Relative to Wet Coal**
	$\mu g/Nm^3$ at 3% O_2		%
FGD Inlet	**12.87**		
FGD Outlet	**11.65**	**6.56**	**43.7**
Bypass		**11.72**	
Stack	**11.80**		

As previously discussed, due to the FGD bypass stream, Hg^T concentration measured at the stack is higher compared to the Hg^T concentration measured at the FGD outlet. Therefore, to determine reduction in total mercury between the FGD inlet and the stack, a relationship between the Hg^T concentration measured by sorbent traps and stack Hg CEM monitor is needed.

Comparison between Hg^T concentration in the stack measured by the plant CEM, and Hg^T concentration measured by sorbent traps at the FGD outlet is presented in Figure 92. Numerical values are summarized in Table 25. As expected, Hg^T concentration measured by the plant CEM is higher compared to the Hg^T concentration measured at the FGD outlet. This difference is partially due to untreated FGD bypass stream having higher Hg^T concentration compared to the FGD outlet (oxidized mercury not being removed by the FGD), see Table 25. Mixing of the untreated FGD bypass stream and treated flue gas stream leaving the scrubber results in higher Hg^T concentration in the stack compared to the FGD outlet. Also, part of the difference in Hg^T concentration measured at the stack and FGD outlet could be due to calibration uncertainty of the plant Hg CEM or due to non-representative location of the sorbent trap (point measurement at the FGD outlet).

Assuming sorbent trap measurements at the FGD outlet are representative, and using relationship between Hg^T concentration measured at the stack by the plant Hg CEM and at the FGD outlet by sorbent traps, presented in Figure 92, gives Hg^T concentration values in the stack for wet coal baseline and preliminary tests with dried coal of 11.26 and 8.54 $\mu g/Nm^3$ at $3\%O_2$, respectively. This corresponds to reduction in Hg^T concentration at the stack of 24 percent, compared to wet coal. It has to be noted that for wet coal stack Hg^T concentration determined from Figure 92 is extrapolated. Also, only five points are available to develop correlation between Hg^T concentration at the stack and FGD outlet, further increasing the uncertainty.

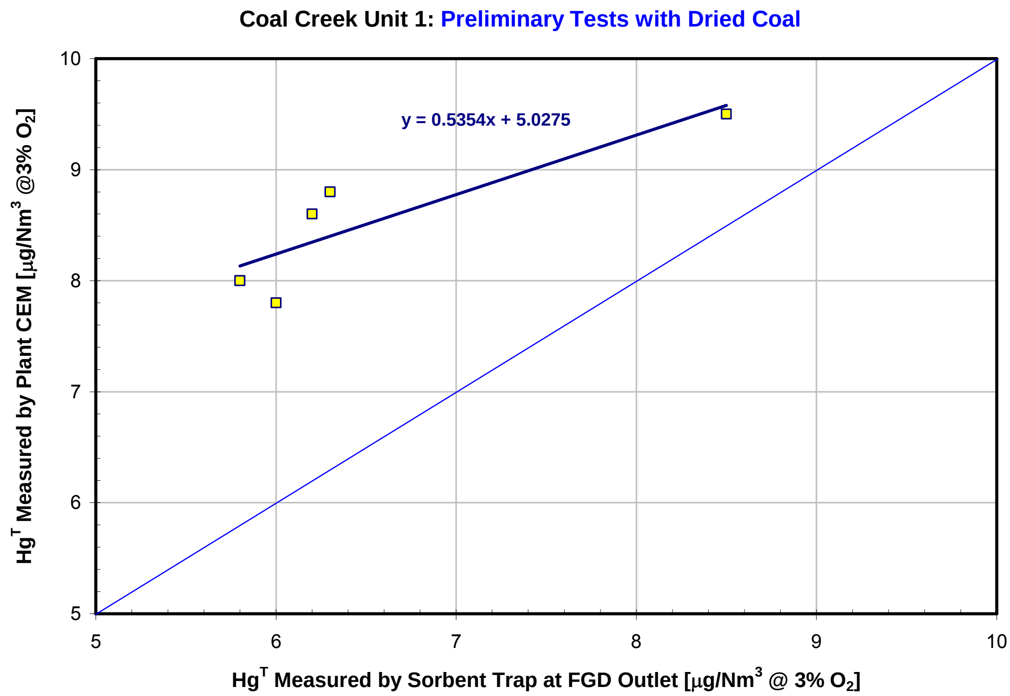

Figure 92: Total Hg Measured by Plant CEM and Sorbent Traps

Table 25: Total Mercury Measured by Sorbent Traps and Plant CEM

Total Mercury (Hg^T)			Sorbent Trap		Plant Hg CEM
Date	Start Time	End Time	FGD Outlet	FGD Bypass	Stack
			$\mu g/Nm^3$ at $3\%O_2$		
3/31/2010	9:12	11:42	8.50	13.70	**9.50**
3/31/2010	13:04	15:34	6.20	11.40	**8.60**
3/31/2010	16:00	17:00	6.30	11.50	**8.80**
4/1/2010	9:00	11:30	5.80	11.20	**8.00**
4/1/2010	13:00	15:30	6.00	10.80	**7.80**

Considering above-discussed uncertainties, more accurate method of determining absolute reduction in Hg concentration and mass emissions involves data reported by the plant Hg CEM monitor. Since plant Hg CEM was calibrated in October 2009 no Hg CEM data is available for direct comparison with the sorbent trap measurements conducted during wet coal baseline tests.

Total mercury concentration measured by the plant Hg CEM is presented in Figures 93 and 94. Figure 93 presents variation in Hg^T concentration over the mid October 2009 to early March 2010 time period. With wet coal, Hg^T varied from 12 to 14 $\mu g/Nm^3$ at 3% O_2. After the coal drying system was put in service, Hg^T decreased. The decrease in Hg^T was moderate (approximately 12.5 percent because air jig was not running during this time period and segregation coal stream was not cleaned (i.e., sulfur and mercury segregated from the feed stream in a FBD were not removed. Uncleaned segregation coal stream was mixed with the product stream).

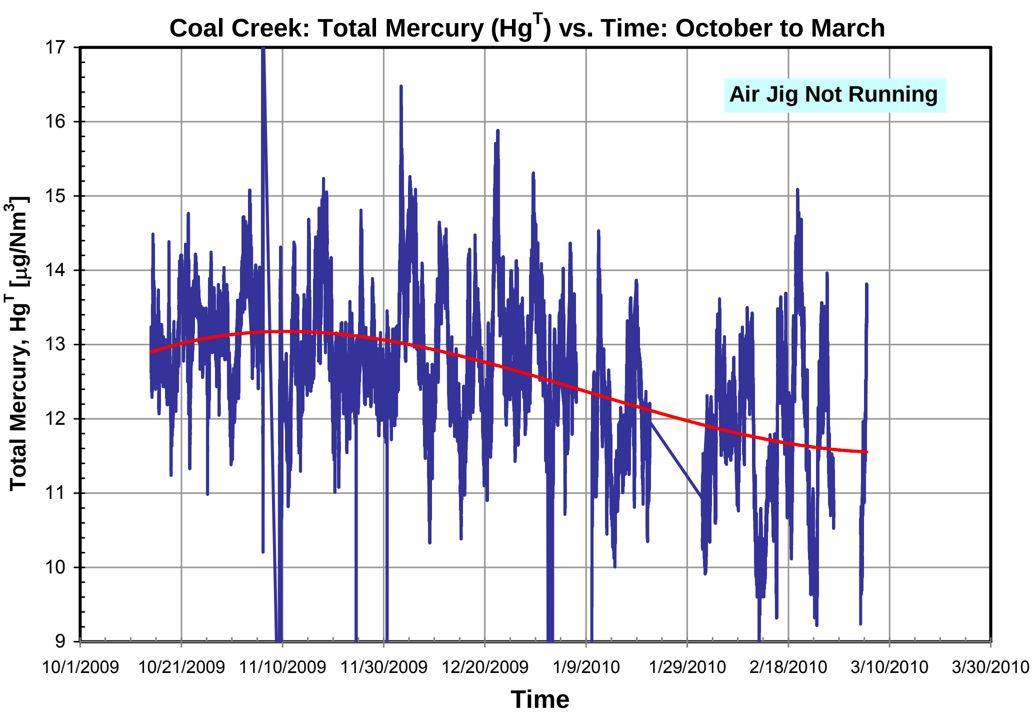

Figure 93: Variation in Stack Hg^T Concentration: October 2009 to March 2010

Variation in Hg^T concentration measured by the plant Hg CEM during March 2010 is presented in Figure 94. As data show, with air jig in service, stack Hg^T concentration decreased significantly. For preliminary tests 2A and 2B conducted with dried coal, stack Hg^T decreased below 9 μg/Nm3 at 3% O_2, resulting in approximately 36 percent reduction in mercury.

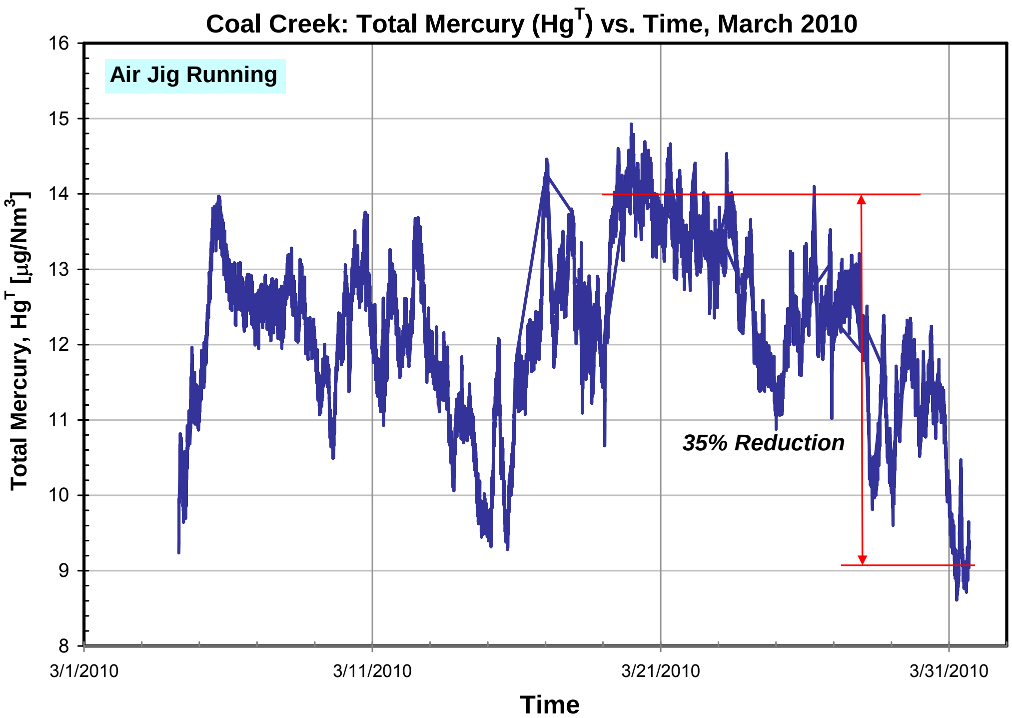

Figure 94: Variation in Stack Hg^T Concentration: March 2010

For preliminary tests 3A and 3B with dried coal, stack Hg^T concentration decreased to 7.8 to 8.0 $\mu g/Nm^3$ at 3% O_2 (see Table 25), resulting in approximately 42.8 to 44.3 percent reduction in mercury. On average, stack Hg^T concentration measured by the plant CEM during preliminary tests with dried coal decreased by approximately 40 percent, compared to wet coal baseline.

Taking into account that flue gas flow rate, measured by the plant CEM, is approximately 3 percent lower with partially dried coal compared to wet coal baseline, mass emissions of mercury will be reduced by approximately 41 percent relative to the wet coal baseline.

9. COMMERCIALIZATION

A Commercialization plan was agreed to and signed as part of the original agreement between Great River Energy and the Department of Energy. Nearly half the global coal reserves are low-rank and from the start, there has been much global interest. In 2009 an agreement was signed by GRE and WorleyParsons giving the engineer exclusive right to license DryFining^{TM}, the trademark name for the technology.

In 2007, Great River Energy and partners looked at design and construction of a coal to liquids facility utilizing North Dakota lignite. The price of oil dropped and the plans were put on hold had progressed to the point where DryFining^{TM} was selected in combination with Siemens gasifiers in an independent study by the owners engineers. DryFining^{TM} has also been integrated (on paper) with an oxy-firing system.

Great River Energy has elected to also utilize the Prototype Dryer and with modification will become the production dryer for Spiritwood, a Combined Heat & Power Plant (CHP) 150 miles from Coal Creek Station. It will continue to process 600,000 tons per year at Coal Creek and the beneficiated lignite will then be shipped by rail to that facility. A barley malting plant exists at Spiritwood now and plans are also being formulated to integrate a cellulosic ethanol plant as well. The three plants will utilize the steam produced to their best advantage. Operation should commence in 2011.

To date, Great River Energy has had 63 confidentiality agreements signed mostly by vendors and suppliers of equipment however, 15 by utilities. We've had agreements signed from companies in Canada, Australia, China, India, Indonesia, and Europe. Three preliminary evaluations have been completed; two in Texas and one in Canada at two separate stations. Preliminary analysis shows comparative improvements can be realized at those stations. Both utilities are presently determining whether to go on to Phase 2 (a more detailed evaluation of the costs and benefits of installation).

The 2 ton per hour Pilot Plant has characterized many coals through central North America; from Texas to Canada. Three Powder River Basin coals have also been characterized. All coals dry however some do not segregate as readily. Coals with inorganically bound minerals are more likely to segregate.

The pilot plant will continue to characterize other coals and plans are in place to do more in the summer of 2010. A secondary market is believed to be those plants who switched from a higher sulfur eastern bituminous to low sulfur western PRB but lost a level of performance due to the lower heating value. DryFining™ should be able to recover that margin.

Based on the positive operational results and savings achieved, Great River Energy has made a commitment to make DryFining™ commercially available to other utilities that can benefit from cleaner and drier coal.

DryFining™ is a process integration, rather than a piece of equipment, and significant engineering and customization is required for a successful implementation. To this end, Great River Energy has entered into a commercialization agreement with WorleyParsons, as the exclusive licensor and process integrator of DryFining™ technology. WorleyParsons is an experienced engineering, procurement and construction management (EPCM) organization with offices throughout the world.

The commercialization approach consists (see Figure 95) of a phased, stage-gated process beginning with a confidentiality agreement and high level screening questionnaire to ascertain the basic fuel characteristics and sources of waste heat and space for integration. If positive, the first formal stage entails entering into a professional services agreement with WorleyParsons for a Phase

I - Feasibility Assessment encompassing fuel sample testing, plant walk down and collection of detailed operational data in order to develop a preliminary layout, estimate, and performance analysis.

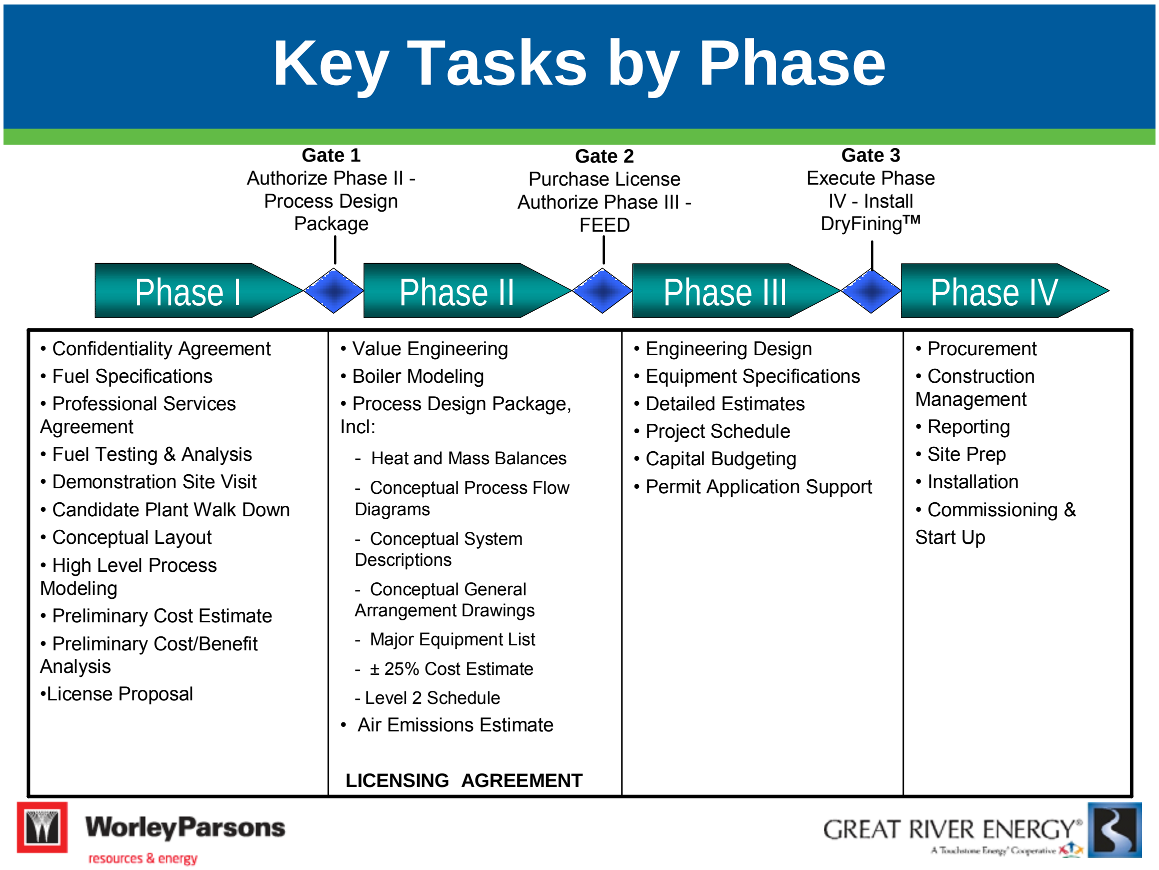

Figure 95: Commercialization Approach: Key Tasks by Phase

At the conclusion of each phase the prospective client has enough information to make an informed decision as to whether or not to proceed to the next level of engineering and investment.

The Phase II – Process Design Package delivers heat and mass balances, general arrangement drawings, major equipment list, and a ±25% total installed cost estimate. At the end of Phase II, the Technology License Fee is due in order to receive a Process Design Package.

Phases III and IV are the normal Front End Engineering Design and Implementation Phases leading to full installation and commissioning.

To date, WorleyParsons is receiving interest from all parts of the world including North America, Southeast Asia and Australia where low rank coals are predominant.

> “*DryFining*TM *turned out to be the most economical solution for achieving long-term environmental compliance. It is a rare opportunity to combine environmental improvement, heat rate improvement, operational improvement and expense reduction in one package. Rather than increasing our O&M budget to achieve environmental improvements, we estimate more than $30 million per year in expense reductions in fuel, auxiliary power and consumables.”*
>
> **John Weeda, Plant Manager Coal Creek**

10. SUMMARY AND CONCLUSIONS

A process that uses plant waste heat sources to evaporate a portion of the fuel moisture from the lignite feedstock in a moving bed fluidized bed dryer (FBD) was developed in the U.S. by a team led by Great River Energy (GRE).

The objectives of GRE's Lignite Fuel Enhancement project are to demonstrate a 8.5%-point reduction in lignite moisture content (about ¼ of the total moisture content) by using heat rejected from the power plant, apply technology at full scale at Coal Creek Station (CCS), and commercialize coal drying technology. The research was conducted with Department of Energy funding under DOE Award Number: DE-FC26-04NT41763.

Phase 1: Prototype Coal Drying System

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station using phased approach. In Phase 1 of the Lignite Fuel Enhancement project, a full-scale prototype coal drying system, consisting of a nominal 75 t/hr fully instrumented two-stage fluidized bed coal dryer, baghouse, crusher, and coal handling system was designed, constructed, and integrated with Coal Creek Unit 2 heat sources and coal handling system. The prototype FBD operated over a range of operating conditions almost continuously from February 2006 to summer of 2009. During this period, it processed more than 650,000 tons of raw coal at throughputs as high as 105 tons/hr, and confirmed the capability of the full-scale dryer to reduce fuel moisture to the target level. Performance of the prototype coal drying system and effect of dried coal on unit performance and emissions were determined in a series of controlled tests. Also, the prototype FBD confirmed that the density segregation effects observed during pilot testing translated to the full-scale device. Results are provided in Section 3.2 of the report and in Reference 1.

Phase 2: Commercial Coal Drying System

The objectives of Phase 2 of the GRE's Lignite Fuel Enhancement project included design, construction and integration of a full scale commercial coal drying system with Coal Creek Units 1 and 2 heat sources and coal handling system, and determination of effect of dried lignite on unit performance, emissions, and operation. Commercial coal drying system at Coal Creek includes four commercial size moving bed fluidized bed dryers per unit, crushers, conveying system to handle raw lignite, segregated, and product streams, particulate control system, and control system. The system is fully instrumented for process monitoring and control. System commissioning was completed in December 2009.

Two series of controlled tests were conducted at Coal Creek Unit 1 with wet and dried lignite to determine effect of dried lignite on unit performance, emissions and operation. Wet lignite was fired during the first, baseline, test series (wet coal baseline) conducted in September 2009. The second test series was performed in March/April 2010 after commercial coal drying system was commissioned, using dried and cleaned lignite where segregation stream was cleaned by air jigs before being mixed with the product stream (preliminary tests with dried lignite).

Functional tests of coal dryer 11 were conducted in January 2010 to establish preliminary information on the dryer and baghouse operation and performance during controlled test conditions. Tests were performed with higher than design coal feed rate and heat input to the dryer at 70 and 85 percent of design value. Results, including drying performance and segregation of sulfur and ash, are described in Section 5.2 of the report.

September 2009 test data were used to establish baseline performance and emissions levels. Test protocol and collected data are described in Section

6 of the report. Test unit (Unit 1) was operated at steady state conditions during the test. Turbine cycle was isolated by switching auxiliary steam extractions to Unit 2. Unit performance (boiler efficiency and net unit heat rate) were determined using several methods. Performance results are summarized in Section 7.4 of the report.

Preliminary tests with dried coal were performed in March/April 2010. During the test Unit 2 was in outage and, therefore, Unit 1 (test unit) was carrying entire station load and, also, providing auxiliary steam extractions. This resulted in higher station service and turbine cycle heat rate. Although, some of these effects could be corrected out, this would introduce uncertainty in calculated unit performance and effect of dried lignite on unit performance. Operating conditions during wet coal baseline and preliminary tests with dried coal are presented in Section 7.1 of the report.

Baseline tests with dried coal are planned for second half of 2010 when both units at Coal Creek will be in service to establish baseline performance with dried coal and determine effect of coal drying on unit performance. Also, it is expected that by that time there will be sufficient operating experience with the coal drying system to assess effect of dried lignite on unit operation.

NO_x, SO_2, and CO_2 Emissions

NO_x, SO_2, and CO_2 concentration in flue gas was measured by the plant CEM. In addition, CO_2 concentration in flue gas at the stack was calculated using stoichiometry, information on coal composition, excess O_2 level at the boiler and APH exit (or scrubber inlet), and humidity of ambient air. Data on NO_x and SO_2 emissions rates were provided by the plant CEM.

Mass emissions of SO_2 were calculated using emissions rate provided by the plant CEM and values of CEM heat input. Actual values of F_c factor were used instead of default value. F_c values were calculated using measured values of CO_2 concentration in flue gas at the stack and coal HHV. Results show that for preliminary tests conducted with dried coal F_c value was significantly higher compared to the default value and F_c value corresponding to the wet coal baseline. The CO_2 mass emissions rate was calculated using calculated CO_2 concentration, and flue gas flow rate, stack temperature and pressure measured by the plant CEM monitor. Results concerning emissions parameters measured or calculated for tests performed with wet and dried lignite at Coal Creek are summarized in Table 26.

For preliminary tests performed with dried coal (lignite) NO_x concentration and emissions rate decreased by 29 and 31.8 percent, respectively relative to the wet coal. SO_2 concentration, emissions rate and mass emissions decreased by approximately 52 and 54 percent, respectively relative to the wet coal.

Table 26: Effect of Dried Lignite on Emissions Parameters: Coal Creek

Parameter (Measured or Calculated at Stack)	**Units**	**Wet Coal Baseline**	**Prelimary Dried Coal Tests**	**% Change Realtive to Wet Coal**	**Absolute Change Relative to Wet Coal**
Measured NO_x Concentration	ppmv	148	105	**-29.0**	-43
NO_x Emissions Rate	lb/MBtu	0.284	0.194	**-31.8**	-0.090
Measured SO_2 Concentration	ppmv	216	103	**-52.3**	-113
SO_2 Emissions Rate	lb/MBtu	0.577	0.265	**-54.1**	-0.312
SO_2 Mass Emissions	lb/hr	3,315	1,522	**-54.1**	-1,793
Calculated H_2O Concentration	% vol	14.40	12.40	**-13.9**	**-2.00**
Measured CO_2 concentration	% vol	11.88	12.35	**4.0**	**0.47**
Calculated CO_2 concentration	% vol	13.06	13.04	**-0.2**	-0.02
Measured CO_2 concentration	% wt	18.10	18.77	**3.7**	**0.68**
Calculated CO_2 concentration	% wt	19.90	19.82	**-0.4**	-0.08
CO_2 Mass Emissions (Measured CO_2)	klb/hr	1,229	1,232	**0.2**	3
CO_2 Mass Emissions (Calculated CO_2)	klb/hr	1,352	1,301	**-3.8**	-51
CEM CO_2 Mass Emissions	klb/hr	1,249	1,251	**0.2**	2
CO_2/Carbon in Coal	%wt/%wt	0.484	0.471	**-2.9**	-0.014
F_c Factor	scf/MBtu	1,922	1,985	**3.3**	63
Flue gas flow rate	kacfm	2,017	1,860	**-7.8**	-157
	klbs/hr	6,793	6,562	**-3.4**	-231
Calculated CEM Heat Input	MBtu/hr	5,694	5,525	**-3.0**	-169

CO_2 concentration measured by the plant monitor for preliminary tests conducted with dried coal increased 4 percent relative to the wet coal baseline. This increase can be attributed to 2%-point lower moisture content in the flue gas and 0.8%-point higher carbon content in as-received lignite, compared to the wet coal. Also, measured CO_2 concentration values could have been affected by instrument drift. Annual RATA test was performed before September 2009 wet coal baseline test.

Calculated values of CO_2 concentration were higher compared to measurements. CO_2 mass emissions rate determined from calculated values of CO_2 concentration for preliminary tests with dried coal were approximately 3.8 percent lower compared to the wet coal. Specific CO_2 emissions expressed as weight percentage of CO_2 in the flue gas divided by carbon content in coal (also expressed on percentage basis) for dried coal were approximately 2.9 percent lower relative to the wet coal.

Corrections for change in coal composition on emissions (and performance) are needed for accurate comparison of CO_2 emissions (and performance). As an alternative, CO_2 emission can be calculated from the mass and energy balance for the unit. This approach requires accurate information on turbine cycle performance.

For preliminary tests with dried coal mass and volumetric flow rates of flue gas were 3.4 and 7.8 percent lower compared to the wet coal. Lower flow resulted in lower fan power requirements and allowed higher portion of flue gas to be scrubbed in the FGD, resulting in reductions in sulfur and mercury. CEM heat input, calculated by using actual values of F_c factor, was approximately 3 percent lower for dried coal compared to the wet coal.

Hg Speciation and Emissions

Flue gas mercury concentration and changes in speciation were determined during wet coal baseline tests and preliminary tests with dried coal using sCEMs and sorbent traps as discussed in Section 6 of the report.

With dried coal, average Hg^T concentration measured by the sCEMs at the wet FGD inlet decreased by approximately 14 percent relative to the wet coal. Hg speciation at the FGD inlet increased from 27 to 42 percent. The reduction in Hg^T concentration and the added benefit of Hg oxidation which promotes additional Hg capture in the FGD is most likely a direct result of reduced volumetric flow rate of flue gas (increased residence time), and flue gas temperatures (faster quenching of the flue gas) under dried coal conditions.

Also, with dried coal average Hg^T concentration measured at the FGD outlet decreased by approximately 27 percent relative to the wet coal. This corresponds to increase in native Hg^T removal across the FGD from 15 to 35 percent. The FGD removed most of the Hg^{2+} from the flue gas, reducing its concentration from 27 to 7 percent for the wet coal, and from 42 to 6 percent for the dried coal. This corresponds to an increase in native removal of Hg^{2+} across the FGD from 74 to 86 percent. Native Hg^T removal across APH, ESP, and FGD for the dried coal, measured by the sCEMs, was 38 percent, approximately 23 percent higher compared to the wet coal.

With dried coal, re-emission of Hg^0 was reduced from 33 percent for wet coal to 17 percent for dried coal further reducing Hg emissions. Therefore, with dried coal, smaller amount of additive for Hg^0 retention in the FGD liquor would be needed to control re-emissions of Hg^0.

With dried coal, the reduction in Hg^T concentration, measured by sorbent traps at the FGD outlet was almost 44 percent, relative to the wet coal. However, due to mixing of untreated FGD bypass stream with treated flue gas stream leaving the FGD, Hg^T concentration in the stack is higher compared to the FGD outlet. Although it is possible to develop a correlation between Hg^T concentration at the stack and FGD outlet to determine reduction in stack mercury emissions, this will undoubtedly introduce additional uncertainties in the calculation.

Considering above-discussed uncertainties, a more accurate method of determining absolute reduction in Hg concentration and mass emissions involves use of data reported by the plant Hg CEM monitor. The average reduction in Hg^T concentration measured by the plant Hg CEM monitor was approximately 40 percent. Accounting for 3 percent reduction in the flue gas flow rate, gives reduction in mass emissions rate of 41 percent relative to the wet coal baseline.

11. REFERENCES

1. Bullinger, C. W. and Sarunac, N., "Lignite Fuel Enhancement Final Technical Report: Phase 1," DOE Award Number: DE-CF26-04NT41763, November, 2006.
2. Katalambula, H. and Gupta, R., "Low-grade coals: A review of some prospective upgrading technologies," Energy & Fuels 2009, 23, (7), 3392-3405.
3. Sarunac, N., "Effect of Coal Drying on Unit Performance and Operation," Prepared for the Cooperative Power, Energy Research Center Report, October 1997.
4. Bullinger, C., Ness, M., Sarunac, N. and Levy, E. K., "Coal Drying Improves Performance and Reduces Emissions," Presented at the 27th International Conference on Coal Utilization & Fuel Systems, Clearwater, Florida, March 4-7, 2002.
5. Ness, M., Krumwiede, J., and Weinstein, R., "Pilot Fluidized Bed Coal Dryer: Operating Experience and Preliminary Results," Presented at the 29th International Conference on Coal Utilization & Fuel Systems, Clearwater, Florida, April 18 - 22, 2004.
6. Bullinger, C., Ness, M, Sarunac, N., "Coal Creek Prototype Fluidized Bed Coal Dryer: Performance Improvement, Emissions Reduction, and Operating Experience," Presented at the 31st International Conference on Coal Utilization & Fuel Systems, Clearwater, Florida, May 21-25, 2006.
7. Sarunac, N., and Levy, E. K., "RPHMT (Air Preheater Metal Temperature Code) Version 1.1, User's Guide for Mainframe Computer Applications", EPRI Project RP1681/2153, April 1989.