Fuel Capability Demonstration Test Report 3 for the JEA Large-Scale CFB Combustion Demonstration Project

Illinois 6 Coal Fuel

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Prepared by Black & Veatch for:

JEA

Building Community

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1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
  - Particulate matter (PM)
  - Oxides of nitrogen (NO_x)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Ammonia (NH_3)
  - Lead (Pb)
  - Mercury (Hg)
  - Fluorine (F)
  - Dioxin
  - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests firing an Illinois 6 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to the steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F when firing Pittsburgh 8 coal.

The fuel capability demonstration test for the unit firing the coal was conducted over a three (3) day period beginning on June 7, 2004 and completed on June 9, 2004. During that three (3) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load , 60% load, and 40% load.

The following log represents the sequence of testing:

- Day 1 — June 7 and June 8, 2004:
  - Unit at 100% load - Began ramp down to 180 MW (60%) at approximately 1800 hours.
  - Unit stabilized at 2323 hours.
  - Boiler performance testing commenced at 0100 hours, June 8, 2004; completed at 0500 hours - no equipment issues.

  (June 8, 2004)
  - At 0623 hours, began ramp up to 100% load - turbine load set and maintained at approx. 300 MW at 0835 hours.
  - Flue gas testing and boiler performance testing commenced at 0900 hours.
  - Boiler performance testing completed at 1600 hours.
  - The A1 fuel feeder went off-line at approximately 1030 hours. A decision was made to leave the fuel feeder off-line, redistribute the fuel, and continue the test. The unit was allowed to stabilize. The test continued at 1200 hours. The boiler performance test and the flue gas test were both completed at approximately 1600 hours.

- Day 2 — June 8 - 9, 2004:
  - Began ramp down of unit to 40% load - turbine load set and maintained at approx. 120 MW at approximately 2230 hours.
  - Unit began 2-hour stabilization period at 120 MW at 2230 hours.

  (June 9, 2004)
  - Boiler performance testing commenced at 0100 hours after stabilization period completed; test completed at 0500 hours - no equipment issues.

- Day 2 (cont'd) — June 9, 2004:
  - Began ramp up of unit to 100% load at approximately 0600 hours - turbine load set and maintained at approx. 300 MW.
  - Boiler performance testing commenced at 1000 hours after stabilization period completed; test completed at 1400 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

  June 9, 2004 (continued)
  - Began ramp down to 80% load at 1800 hours; A1 feeder out of service.
  - Unit reached 240 MW at 1830 hours, began stabilization period.
  - Test commenced at 1930 hours; test completed at 2330 hours, no equipment problems.
  - Test #3 complete.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Fly ash
FF	Fabric Filter
gpm	gallons per minute
gr/acf	grains per actual cubic foot

Abbreviation	Definition
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside
Pb	Lead

Abbreviation	Definition
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1
W_{fe}	Fuel feed rate (lb/hr)

Abbreviation	Definition
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, per cent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, per cent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions (NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

No design performance data for the boiler firing the Illinois 6 fuel were provided by Foster-Wheeler. For the purposes of this report, the results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler, as follows:

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test were compared with the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the ‘closed’ position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The boiler and SDA SO2 removal efficiencies are summarized in Table 2. The results of the part-load tests are summarized in Table 3. Although the boiler performance values did not meet the design values provided by Foster-Wheeler, the boiler output was adequate to keep the turbine at the required output. During the first 100% MCR test (June 8, 2004), the A1 feeder tripped. A decision was made to leave the A1 feeder out of service and continue with the testing. No other equipment problems were experienced.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	June 8, 2004 Test (**corrected to MCR, see Note 4)	June 9, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Pittsburgh 8 Coal)	88.3 ** (Note 1)	88.0 **(Note 1)
Capacity Calculation (percent)	NA	101.5	100.0
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,974,013 **	1,926,677 **
Pressure (psig)	2,500	2,400	2,400
Temperature (°F)	1,000	998 **	999 **
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,897,211	1,859,959
Pressure (psig)	547.7	571.5	573.0
Temperature (°F)	1,000	1,005	1,011
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,897,091	1,851,738
Pressure (psig)	608.6	570.9	572.3
Enthalpy (Btu/lb)	1,304.5	1,293.6	1,285.6
Feedwater to Economizer			
Temperature (°F)	487.5	484.1	484.6
Illinois 6 Fuel Analysis (As-Received)			
Carbon %	64.48	64.93	64.70
Hydrogen %	4.40	4.31	4.57
Sulfur %	2.71	3.17	3.32
Nitrogen %	1.24	1.27	1.26
Chlorine %	0.15	0.15	0.15
Oxygen %	7.34	7.14	7.37
Ash %	8.57	7.08	6.59
Moisture %	11.11	12.10	12.19
HHV (Btu/lb)	11,603	11,649	11,664
Fuel Flow Rate (lb/hr)	NA	232,730	232,535
Limestone Composition (% By Weight)			
$CaCO_3$	92.0	96.6	96.77
$MgCO_3$	3.0	1.3	1.39
Inerts	4.0	2.1	1.84
Total Moisture	1.0	0.16	0.22

	Design Maximum-Continuous Rating (MCR)	June 8, 2004 Test (**corrected to MCR, see Note 4)	June 9, 2004 Test (**corrected to MCR, see Note 4)
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	64,005	73,001
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.086	0.103
Uncontrolled SO2, lb/MMBtu (HHV)	7.49	5.44	5.69
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2763	0.2887
Stack SO2 lb/MMBtu, (HHV)	0.15	0.107	0.08
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0019	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0198	0.024
Opacity, percent	10	1.5	1.0
Ammonia (NH3) Slip, ppmvd	2.0	< 0.5206	
Ammonia feed rate, gal/hr	NA	5.53	6.76
Lead, lb/MMBtu	2.60×10^{-5} (max)	$< 4.352 \times 10^{-7}$	
Mercury (fuel), µg/g	NA	0.50	
Mercury, lb/TBtu (at stack)	10.5 (max)	0.345	
Total Mercury Removal Efficiency, percent	No requirement	95 (see Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 4.582 \times 10^{-5}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of Attachment A, FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	June 8, 2004 Test	June 9, 2004 Test
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	94.9	95.0
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	3.17	3.7
Percent of Total SO2 Removed	97.1	98.0	98.6
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	61.0	72.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.68	2.43

TABLE 3 - TEST RESULTS - PARTIAL LOADS

	June 9	June 8	June 9
Percent Load	80%	60%	40%
Unit Capacity (MW)	240	180	120
Capacity Calculation (percent)	82.21	55.50	38.27
Total Main Steam Flow, lb/hr	1,541,871	1,087,192	715,411
Main Steam Temperature, deg F	1,001	1,002	1,001
Main Steam Pressure, psig	2,400	1,700	1,200
Cold Reheat Steam Temperature, deg F	561	575	561
Hot Reheat Steam Temperature, deg F	1,007	966	1,004
NOx, lb/MMBtu	0.064	0.053	0.078
CO, lb/MMBtu	0.031	0.0338	0.138
SO2, lb/MMBtu	0.079	0.144	0.108
Opacity, percent	1.3	1.6	1.4

2.3.1 Unit Capacity - During the three (3) day testing period, the boiler was successfully operated at a turbine load of approximately 300 MW, for day 1 and day 2, and at partial turbine loads of approximately 240 MW, 180 MW, and 120 MW on the days indicated in Article 1.1, Test Schedule. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 88.3 % and 88.0% on Day 1 and Day 2, respectively, of the testing period. The average of these efficiencies was 88.1 and was equal to the design value for firing Pittsburgh 8 coal guaranteed by Foster-Wheeler.

2.3.3 Steam Temperature - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 998.5 deg F, which is slightly below the design tolerances of the unit. The turbine generator output correction for an initial main steam temperature reduction of 1.5 F would be a reduction of only about 0.06 MW. Additionally, the corrected hot reheat steam temperature measured at the turbine inlet was 1,008 deg F, which is within the design tolerances of the unit. The main steam temperatures and the hot reheat temperatures for the 80% and 40% partial load operating conditions were within the design tolerances previously listed in Section 2.1. The hot reheat temperature for the 60% partial load condition was 966 deg F which is approximately 24 deg F below the minimum tolerance indicated in Section 2.1 of 990 deg F. The unit, however, was able to maintain load, the effect being a slightly worse overall plant heat rate.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected for deviations from the design MCR feedwater temperature. Although the corrected main steam flow rates determined for the 100% load operation cases were less than the design flow rates established by Foster-Wheeler, the main steam flow rates were adequate to maintain the steam turbine at the desired plant output. The primary reason plant output could be maintained is that the Foster Wheeler design flow rates included an approximately 2.5% design margin on main steam flow above that required by the turbine generator, to compensate for plant performance degradation over time. The main steam flow rates at the partial load operation cases were adequate to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing the coal was 2.88. The calculated calcium to sulfur ratios for Day 1 and Day 2 are approximately 2.68 and 2.43, respectively. These values represent SO2 removal efficiencies for the boiler of greater than 90 % which are acceptable values for a CFB. SO2 reductions of greater than 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. No significant operational restrictions were observed during testing at the 100% MCR condition.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, fly ash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT/ESC. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT/ESC and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly Ash (Figures 2, 3, and 4):</u>

Fly Ash samples were taken by two different methods.

1) Fly ash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Fly ash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

Bed Ash (Figure 6):

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data at the 100%, 80%, 60% and 40% performance load tests were collected by the CEMS.

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.086 lb/MMBtu and 0.103 lb/MMBtu, respectively. During Day 2 of the test, operational problems with the ammonia injection system prevented plant operations from limiting NOx levels.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2 concentration at the air heater outlet was expected to be 0.78 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 7.49 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

   The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.28 lb/MMBtu and 0.11 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 94.9% and 95% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 5.44 lb/MMBtu and 5.69 lb/MMBtu, respectively, for a decreased SO2 input of 27% and 24% below the design performance coal SO2 input of 7.49 lb/MMBtu.

   The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.107 lb/MMBtu and 0.08 lb/MMBtu, respectively. These values were 29% and 47% lower than the 0.15 lb/MMBtu permitted emission rate.

c. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.0019 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.0198 lb/MMBtu and 0.024 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and Fluorine were sampled only at the stack by CAE. The average values are indicated in Table 1.

4.3.4.1 Mercury Removal
Mercury in the stack flue gas was expected to be less than or equal to 10.5 lb/TBtu HHV fuel heat input at 100% MCR. The average values for the test were 0.345 lb/TBtu. The average mercury value at the inlet to SDA/FF for the test was 7.098 lb/TBtu, for a 95 percent removal efficiency across the SDA/FF. The mercury tests were conducted utilizing the Ontario Hydro Test Method. Refer to the report prepared by CAE, Attachment C, Table 2-5 and Table 2-8.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions testing were not required for evaluation of the coal.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 1.8%, which is much less than the maximum opacity value.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by

KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**88.29**
Test Date:	**June 8, 2004**		
Test Start Time:	**9:00 AM**		
Test End Time:	**4:00 PM (BREAK IN TEST FROM 11 AM TO 2 PM)**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	232,730	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.6482	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0444	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0726	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0127	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0325	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0684	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.1215	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	11,657	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	64,005	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9668	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0137	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0196	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0019	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.983		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reported.
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	305	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0134	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0134	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.0119	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	28,844	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0388	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0388	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.0346	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	43,437	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	103	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	34	LB/HR	
1.5.4	Fan Outlet Temperature, °F	103	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	1,437,205	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	99	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	43,361	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	182	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	36,540	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	200	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 (100% Load)	Boiler Efficiency:	88.29
Test Date:	June 8, 2004		
Test Start Time:	9:00 AM		
Test End Time:	4:00 PM (BREAK IN TEST FROM 11 AM TO 2 PM)		
Test Duration, hours:	4		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	84.26	°F	ta
1.6.2	Ambient wet bulb temperature, °F	74.56	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.14	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0161	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	314.00	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0466	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	568.82	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0041	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1950.5	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	484.1	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,972,754	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,588.1	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	675.2	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,727.5	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	313.8	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	1,259	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.2	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	998.0	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,974,013	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	945.12	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	312.27	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	120	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	570.89	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	601.75	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	571.53	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,004.75	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,897,091	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

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Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 102.47

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1 ASSUMED FUEL FLOW RATE, lb/h	231,964	lb/h	
3.2 ASSUMED SULFUR EMISSIONS, fraction	0.0416	fraction	Can get reading from CEMS system
3.3 Sulfur Capture, fraction	0.9584		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory		0	lb/h	
4.2 Corrected Ash Carbon Content				
4.2.1	Bottom Ash, fraction	0.0134	lb/lb BA	
4.2.2	Fly Ash, fraction	0.0388	lb/lb FA	
4.3 Bottom Ash Flow Rate				
4.3.1	Total bottom ash including bed change	28,844.3195350	lb/h	
4.4 Limestone Flow Rate				

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	2.6332	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.849230993	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	64005	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 - Cfa')) ·
4.4.4	Calculated Calcium to Sulfur Ratio	2.633225458	mole Ca/mole S	
	Limestone Flow Rate from PI Data, lb/hr	**64,005**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000135296	percent	
4.4.6	Calculated Fly Ash Flow Rate	43,437	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000002)	percent	
4.5 Total Dry Refuse				
4.5.1	Total Dry Refuse Hourly Flow Rate	72,282	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.3116	lb/lb AF fuel	
4.6 Heating Value Of Total Dry Refuse				
4.6.1	Average Carbon Content Of Ash	0.0287	fraction	
4.6.2	Heating Value Of Dry Refuse	415.63	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone			
5.1.1	Carbon Burned	0.6392	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.6712	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**88.29**
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Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.871	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.0229	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	6.7191	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.4594	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5685	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	8.6590	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.1818	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	11.7023	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6643	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	12.4028	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.4945	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.6433	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0110	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.6556	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.5718	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1183	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.655555556	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-0.000391512	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1464		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8070		
5.2.14	Weight Dry FG At Air Heater OUTLET	11.6606	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6590	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.2891	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01001	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.2250	percent volume	
5.2.16.4	Nitrogen from air, volume percent	73.1208	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1074	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.2477	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	12.3611	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.4863	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0486	fraction
5.2.19.2	Nitrogen, fraction weight	0.7413	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2102	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.177	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.4594	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4129	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	8.1420	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1710	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	11.0296	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7744	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	11.7193	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.5430	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.5921	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.6702	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1260	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-0.000395503	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1559	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8040	
5.3.12	Weight Dry FG At Air Heater INLET	11.0426	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.9170	lb/lb mole

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**88.29**
Test Date:	**June 8, 2004**		
Test Start Time:	**9:00 AM**		
Test End Time:	**4:00 PM (BREAK IN TEST FROM 11 AM TO 2 PM)**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.0873	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01061	percent volume
5.3.14.3	Oxygen from air, volume percent	3.2526	percent volume
5.3.14.4	Nitrogen from air, volume percent	72.8845	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1138	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.6512	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	11.7323	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.6680	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7323	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2219	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0085	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0351	fraction
5.3.18.2	Nitrogen, fraction weight	0.6893	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2090	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0080	fraction
5.3.18.6	Moisture, fraction weight	0.0586	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.824	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.4594	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4664	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	8.3199	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1747	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	11.2610	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7349	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	11.9544	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.5257	lb/lb mole

		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	13.8021	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0104	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	72.9690	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1115	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	9.5070	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**88.29**
Test Date:	**June 8, 2004**		
Test Start Time:	**9:00 AM**		
Test End Time:	**4:00 PM (BREAK IN TEST FROM 11 AM TO 2 PM)**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.2521	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.9782	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.6349	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1232	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-0.000334646	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-0.000607987	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		5.281574E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		5.594396E+00
			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		5.8529701E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		6.2759588E+00
			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		5.1313970E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		5.1843010E+00
			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		5.9158924E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		6.3311225E+00

Jacksonville Electric Authority

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Test Date:	**June 8, 2004**		
Test Start Time:	**9:00 AM**		
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Test Duration, hours:	**4**		

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	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.7351689E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	3.8133958E+00		

General equation for constituent enthalpy:
h = C0 + C1 * T + C2 * T² + C3 * T³ + C4 * T * T³ + C5 * T² * T³
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	56.74	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	6.01	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	591.45	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	5.07	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1202.03	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)² + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	70.47	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	137.43	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	1.18	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	448.98	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	3.85	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	129.51	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	1.11	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	6.31	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	7.92	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	14.23	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.12	percent

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**88.29**
Test Date:	**June 8, 2004**		
Test Start Time:	**9:00 AM**		
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Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	11.54	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	155.78	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	50.25	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	19.65	Btu/lb

10.3 HHV Percent Loss, as tested 0.17 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	203.28	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	0.59	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-209.40	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-5.52	Btu/lb AF Fuel

11.5 HHV Percent Loss -0.05 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.25 percent

12.1.1	Radiation & Convection Heat Loss	29.70	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	591.45
13.1.2	137.43
13.1.3	448.98
13.1.4	129.51
13.1.5	14.23
13.1.6	19.65
13.1.7	-5.52
13.1.8	29.70
	1,365.43

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 (100% Load)	Boiler Efficiency:	88.29
Test Date:	June 8, 2004		
Test Start Time:	9:00 AM		
Test End Time:	4:00 PM (BREAK IN TEST FROM 11 AM TO 2 PM)		
Test Duration, hours:	4		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		As Tested Percent Loss
13.1.9	Dry Flue Gas	5.07
13.1.10	Moisture In Fuel	1.18
13.1.11	H2O From H2 In Fuel	3.85
13.1.12	Unburned Combustibles In Refuse	1.11
13.1.13	Dry Refuse	0.12
13.1.14	Moisture In Combustion Air	0.17
13.1.15	Calcination/Sulfation	-0.05
13.1.16	Radiation & Convection	0.25
		11.71
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***88.29***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.28	Btu/lb
14.1.2	Blow Down, Btu/lb	741.43	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	288.63	Btu/lb
14.1.5	Main Steam, Btu/lb	1459.85	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	283.83	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1292.26	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1519.65	Btu/lb

14.2 Heat Output 2,387,171,472 Btu/h

2,388,856,787

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,703,905,132	Btu/h
15.1.2	Fuel Burned - CALCULATED	231,965	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-0.000611546	percent

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency: 87.95**
Test Date:	**June 9, 2004**	
Test Start Time:	**10:30 AM**	
Test End Time:	**4:00 PM**	
Test Duration, hours:	**4**	

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	232,535	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.6482	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0444	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0726	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0127	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0325	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0684	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.1215	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	11,657	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	60,698	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9668	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0137	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0196	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0019	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.983		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reported.
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	362	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0134	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0134	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.0119	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	16,177	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0388	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0388	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.0346	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	54,251	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	103	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	36	LB/HR	
1.5.4	Fan Outlet Temperature, °F	103	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	1,431,294	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	99	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	44,431	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	183	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	37,514	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	202	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 (100% Load)		Boiler Efficiency:	87.95
Test Date:	June 9, 2004			
Test Start Time:	10:30 AM			
Test End Time:	4:00 PM			
Test Duration, hours:	4			

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	83.60	°F	ta
1.6.2	Ambient wet bulb temperature, °F	74.52	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.14	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0163	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	324.11	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0466	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	581.46	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0030	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1948.9	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	484.6	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,924,448	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,580.5	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	674.8	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,719.2	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	317.1	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	2,230	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.4	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	999.5	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,926,677	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	863.00	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	330.88	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	8,221	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	572.29	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	589.56	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	573.00	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,011.23	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,851,738	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2 (100% Load)**	**Boiler Efficiency:**	**87.95**
Test Date:	**June 9, 2004**		
Test Start Time:	**10:30 AM**		
Test End Time:	**4:00 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	102.57	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	230,408	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0415	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9585		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory 0 lb/h

4.2 Corrected Ash Carbon Content

4.2.1	Bottom Ash, fraction	0.0134	lb/lb BA
4.2.2	Fly Ash, fraction	0.0388	lb/lb FA

4.3 Bottom Ash Flow Rate

4.3.1	Total bottom ash including bed change	16,176.9039730	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	2.5140	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.862600112	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	60698	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 - Cfa')) ·
4.4.4	Calculated Calcium to Sulfur Ratio	2.514032348	mole Ca/mole S	
	Limestone Flow Rate from PI Data, lb/hr	**60,698**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-3.8693E-05	percent	
4.4.6	Calculated Fly Ash Flow Rate	54,251	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000012)	percent	

4.5 Total Dry Refuse

4.5.1	Total Dry Refuse Hourly Flow Rate	70,428	lb/h
4.5.2	Total Dry Refuse Per Pound Fuel	0.3057	lb/lb AF fuel

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0330	fraction
4.6.2	Heating Value Of Dry Refuse	478.00	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.6381	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.6686	lb/lb AF fuel

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Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between
the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.860	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.0199	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	6.7090	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.4499	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5674	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	8.6452	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.1830	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	11.6778	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6598	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	12.3795	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.4867	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.6150	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0110	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.6556	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.5998	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1186	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.655555556	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-3.34389E-07	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1462		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8073		
5.2.14	Weight Dry FG At Air Heater OUTLET	11.6311	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6582	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.2592	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01001	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.2236	percent volume	
5.2.16.4	Nitrogen from air, volume percent	73.1224	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1076	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.2773	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	12.3328	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.4811	lb/lb mole	

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0486	fraction
5.2.19.2	Nitrogen, fraction weight	0.7415	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2099	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.169	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.4499	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4121	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	8.1292	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1720	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	11.0065	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7696	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	11.6973	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.5348	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.5620	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.7000	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1262	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-5.7704E-07	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1556	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8054	
5.3.12	Weight Dry FG At Air Heater INLET	11.0048	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8714	lb/lb mole

		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.0554	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01061	percent volume
5.3.14.3	Oxygen from air, volume percent	3.2515	percent volume
5.3.14.4	Nitrogen from air, volume percent	72.8871	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1140	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.6813	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	11.6956	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.6230	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7347	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2218	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0062	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0351	fraction
5.3.18.2	Nitrogen, fraction weight	0.6913	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2088	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0058	fraction
5.3.18.6	Moisture, fraction weight	0.0589	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.824	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.4499	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0027	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4657	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	8.3073	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0127	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.1215	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3968	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0005	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1758	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	11.2383	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7301	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	11.9328	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.5176	lb/lb mole
		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	13.7700	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0104	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	72.9715	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1117	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	9.5365	percent volume
		100.0000	percent volume

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		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.2216	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.9795	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.6640	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1235	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	4.61822E-07	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	1.30248E-05	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		5.511438E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		5.617889E+00
			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		6.1040600E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		6.3022782E+00
			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		5.3646269E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		5.2062217E+00
			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		6.1703045E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		6.3576787E+00

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	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.9033769E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	3.8294948E+00		

General equation for constituent enthalpy:

$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$

T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	59.20	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	6.04	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	618.33	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	5.30	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1206.67	Btu/lb	$hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)^2 + 1062.2 - PTC$
6.2	Saturated Water Enthalpy at tA8	70.57	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	137.98	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	1.18	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	450.78	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	3.87	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	146.11	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	1.25	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	4.56	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	10.43	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	14.99	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.13	percent

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10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	11.51	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	160.89	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	50.31	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	20.71	Btu/lb

10.3 HHV Percent Loss, as tested 0.18 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	194.08	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	0.57	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-209.41	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-14.76	Btu/lb AF fuel

11.5 HHV Percent Loss -0.13 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.26 percent

12.1.1	Radiation & Convection Heat Loss	29.96	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	618.33
13.1.2	137.98
13.1.3	450.78
13.1.4	146.11
13.1.5	14.99
13.1.6	20.71
13.1.7	-14.76
13.1.8	29.96
	1,404.09

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Test End Time:	**4:00 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		As Tested Percent Loss
13.1.9	Dry Flue Gas	5.30
13.1.10	Moisture In Fuel	1.18
13.1.11	H2O From H2 In Fuel	3.87
13.1.12	Unburned Combustibles In Refuse	1.25
13.1.13	Dry Refuse	0.13
13.1.14	Moisture In Combustion Air	0.18
13.1.15	Calcination/Sulfation	-0.13
13.1.16	Radiation & Convection	0.26
		12.05

13.2 Boiler Efficiency (100 - Total Losses), percent 87.95

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.82	Btu/lb
14.1.2	Blow Down, Btu/lb	740.58	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	291.97	Btu/lb
14.1.5	Main Steam, Btu/lb	1460.84	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	302.88	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1284.18	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1523.12	Btu/lb

14.2 Heat Output 2,362,240,699 Btu/h

2,363,757,533

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,685,754,725	Btu/h
15.1.2	Fuel Burned - CALCULATED	230,408	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	2.50693E-05	percent

ATTACHMENT C

CAE Test Report

Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
100% ILLINOIS NO. 6 COAL

Performed for:
BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-3
Revision 0: Draft Release (July 12, 2004)

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

Reviewed by,

Robert A. Preksta
Project Manager
(412) 787-9130
bpreksta@cleanair.com

Timothy D. Rodak
Manager, Pittsburgh Regional Office

CONTENTS

PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of 100% Illinois coal to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3).

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on June 8 and 9, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black and Veatch
R. Huggins – Black and Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-10. Process data collected during the test program is contained in Appendix H.

PROJECT OVERVIEW

Table 1-1:
Summary of Air Emission Field Test Program

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/08/04	09:00	10:26	
2	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/08/04	11:59	13:19	
3	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/08/04	14:52	16:12	
1	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/08/04	09:00	10:00	
2	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/08/04	11:59	12:59	
3	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/08/04	14:52	15:52	
1	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	6/08/04	09:26	11:53	
2	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	6/08/04	13:03	15:15	
3	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	6/08/04	15:50	18:03	
1	Unit 2 - Stack	USEPA Method 5/29	Particulate/Lead	6/08/04	09:00	11:14	
2	Unit 2 - Stack	USEPA Method 5/29	Particulate/Lead	6/08/04	11:59	14:12	
3	Unit 2 - Stack	USEPA Method 5/29	Particulate/Lead	6/08/04	14:52	17:02	
1	Unit 2 - Stack	Ontario Hydro	Mercury	6/08/04	09:00	11:42	
2	Unit 2 - Stack	Ontario Hydro	Mercury	6/08/04	13:03	15:15	
3	Unit 2 - Stack	Ontario Hydro	Mercury	6/08/04	15:50	18:02	
4	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/09/04	10:30	11:39	
5	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/09/04	12:08	14:07	
6	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	6/09/04	14:58	16:22	
4	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/09/04	10:30	11:30	
5	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/09/04	12:08	13:08	
6	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/09/04	14:58	15:38	(1)
7	Unit 2 - SDA Inlet	USEPA Method 6C	SO2	6/09/04	15:58	16:58	(2)
1	Unit 2 - Stack	USEPA Method 13B	Total Fluorides	6/09/04	10:30	11:33	
2	Unit 2 - Stack	USEPA Method 13B	Total Fluorides	6/09/04	12:08	13:10	
3	Unit 2 - Stack	USEPA Method 13B	Total Fluorides	6/09/04	14:04	15:10	
1	Unit 2 - Stack	CTM-027	Ammonia	6/09/04	12:25	13:27	
2	Unit 2 - Stack	CTM-027	Ammonia	6/09/04	13:41	14:54	
3	Unit 2 - Stack	CTM-027	Ammonia	6/09/04	15:14	16:21	

Notes:
(1) SDA Inlet SO_2 Run 6 suspeneded due to problem with Spray Drier.

071204 123150

(2) Gas conditions and volumetric flow data from EPA Method 17 Run 6 were used to convert the SO_2 concentration (ppmdv) into the mass emission rate (lb/hr).

Table 1-2:
Summary of Test Results

Source / Constituent	Sampling Method	Average Emission
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 1-3	EPA M6C	135
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2773
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2671
Sulfur Dioxide (ppmdv), Runs 4-6	EPA M6C	140
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2917
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2786
Particulate (gr/dscf), Runs 1-3	EPA M17	8.0746
Particulate F_d-based, (lb/MMBtu), Runs 1-3	EPA M17/19	14.6439
Particulate F_c-based, (lb/MMBtu), Runs 1-3	EPA M17/19	14.3929
Particulate (gr/dscf), Runs 4-6	EPA M17	10.4218
Particulate F_d-based, (lb/MMBtu), Runs 4-6	EPA M17/19	18.9577
Particulate F_c-based, (lb/MMBtu), Runs 4-6	EPA M17/19	18.6988
Mercury (lb/hr)	Ontario Hydro	1.961E-02
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	7.125E-06
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	7.044E-06
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0010
Particulate (lb/hr)	EPA M5	5.6322
Particulate F_d-based, (lb/MMBtu)	EPA M5/19	0.0019
Particulate F_c-based, (lb/MMBtu)	EPA M5/19	0.0019
Fluoride (lb/hr)	EPA M13B/19	<0.1309
Fluoride F_d-based, (lb/MMBtu)	EPA M13B/19	<4.630E-05
Fluoride F_c-based, (lb/MMBtu)	EPA M13B/19	<4.394E-05
Lead (lb/hr)	EPA M29	<1.273E-03
Lead F_d-based, (lb/MMBtu)	EPA M29/19	<4.368E-07
Lead F_c-based, (lb/MMBtu)	EPA M29/19	<4.319E-07
Mercury (lb/hr)	Ontario Hydro	<9.821E-04
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	<3.467E-07
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	<3.426E-07
Mercury (% Removal)	Ontario Hydro/19	94.9
Ammonia (ppmdv)	CTM-027	<0.5206
Ammonia (lb/hr)	CTM-027	<0.8612
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	<0.0003
Ammonia F_c-based, (lb/MMBtu)	CTM-027/19	<0.0003

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,817 dscf/MMBtu for samples collected on June 8 and 9,882 dscf/MMBtu for samples collected on June 9, 2004. A carbon-based fuel factor (F_c) of 1,7927 scf/MMBtu for samples collected on June 8 and 1,795scf/MMBtu for samples collected on June 9, 2004.
2. Total mercury emission results are shown on above table. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of F_d-based lb/MMBtu.

PROJECT OVERVIEW

PROJECT MANAGER'S COMMENTS

Ontario Hydro Test Results

Each Ontario Hydro sampling train consists of five (5) sample fractions. These fractions, starting from the sampling nozzle, consist of:

1. 0.1N HNO_3 (Front-half Rinse)
2. Filter
3. KCl (Impingers 1 through 3)
4. HNO_3-H_2O_2 (Impinger 4)
5. KMnO4 (Impingers 5 through 7)

An aliquot of each reagent and an unused filter where analyzed for mercury prior to use in the field as an added quality assurance program. All reagent s and the filter blank were below the minimum detection limit for mercury. Results of the pre-blank analysis are contained in Appendix D.

Dry and Carbon Based Fuel Factors

The fuel factors (dry and carbon based) used calculate the lb/MMBtu results were determined from coal samples collected on June 6 and 7, 2004. Each sample was designated as the coal fired the next day i.e., the coal sample collected on June 6 is designated as fired in unit on June 7. The F_d and F_c factors were calculated based on the "As Received" analysis. A copy of the calculations is included with the coal analysis in Appendix H of this report.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 3

Run No.	**1**	**2**	**3**	**Average**
Date (2004)	June 8	June 8	June 8	
Start Time	9:00	11:59	14:52	
End Time	10:00	12:59	15:52	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	**9,817**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	**1,792**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)	4.2	4.4	4.4	**4.3**
Carbon dioxide (dry volume %)	15.1	14.8	15.2	**15.0**
Actual water vapor in gas (% by volume)	9.79	10.29	9.74	**9.94**
Volumetric flow rate, actual (acfm)	1,080,783	1,099,384	1,129,746	**1,103,304**
Volumetric flow rate, standard (scfm)	689,381	692,083	708,445	**696,636**
Volumetric flow rate, dry standard (dscfm)	621,886	620,893	639,469	**627,416**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	153	114	138	**135**
Mass Emission Rate (lb/hr)	950	704	880	**845**
Mass Emission Rate (ton/year)	4,162	3,084	3,856	**3,701**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.3121	0.2346	0.2853	**0.2773**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.3014	0.2286	0.2713	**0.2671**

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 4 through 7

Run No.	4	5	7	Average
Date (2004)	June 9	June 9	June 9	
Start Time	10:30	12:08	15:58	
End Time	11:30	13:08	16:58	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,882	9,882	9,882	**9,882**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,795	1,795	1,795	**1,795**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)				
Carbon dioxide (dry volume %)	15.0	15.1	15.1	**15.0**
Actual water vapor in gas (% by volume)	9.5	9.5	8.6	**9.2**
Volumetric flow rate, actual (acfm)	1,111,343	1,088,895	1,002,215	**1,067,485**
Volumetric flow rate, standard (scfm)	687,036	680,627	633,596	**667,086**
Volumetric flow rate, dry standard (dscfm)	622,032	615,757	579,002	**605,597**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	131	194	96	**140**
Mass Emission Rate (lb/hr)	814	1190	556	**853**
Mass Emission Rate (ton/year)	3,564	5,213	2,436	**3,738**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2743	0.4015	0.1994	**0.2917**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.2617	0.3834	0.1907	**0.2786**

Note: Run 6 aborted due to Spray Drier problem.

RESULTS

Table 2-3: Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jun 8	Jun 8	Jun 8	
Start Time (approx.)		09:00	11:59	14:52	
Stop Time (approx.)		10:26	13:19	16:12	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.8	4.7	4.7	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.2	14.4	14.5	**14.4**
T_s	Sample temperature (°F)	330	332	335	**332**
B_w	Actual water vapor in gas (% by volume)	9.79	10.29	9.74	**9.94**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	1,080,783	1,099,384	1,129,746	**1,103,304**
Q_s	Volumetric flow rate, standard (scfm)	689,381	692,083	708,445	**696,636**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	621,886	620,893	639,469	**627,416**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	7.9579	8.1966	8.0692	**8.0746**
$E_{lb/hr}$	Particulate Rate (lb/hr)	42,433	43,636	44,243	**43,437**
$E_{kg/hr}$	Particulate Rate (kg/hr)	19,244	19,790	20,065	**19,699**
$E_{T/yr}$	Particulate Rate (Ton/yr)	185,856	191,126	193,783	**190,255**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	14.4924	14.8350	14.6043	**14.6439**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	14.3513	14.5765	14.2509	**14.3929**

RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		4	5	6	Average
Date (2004)		Jun 9	Jun 9	Jun 9	
Start Time (approx.)		10:30	12:08	14:58	
Stop Time (approx.)		11:39	14:07	16:22	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,882	9,882	9,882	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,795	1,795	1,795	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.8	4.7	4.5	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.2	14.3	14.4	**14.3**
T_s	Sample temperature (°F)	346	339	330	**339**
B_w	Actual water vapor in gas (% by volume)	9.46	9.53	8.62	**9.20**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	1,111,343	1,088,895	1,002,215	**1,067,485**
Q_s	Volumetric flow rate, standard (scfm)	687,036	680,627	633,596	**667,086**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	622,032	615,757	579,002	**605,597**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	9.9480	12.2715	9.0458	**10.4218**
$E_{lb/hr}$	Particulate Rate (lb/hr)	53,057	64,789	44,908	**54,251**
$E_{kg/hr}$	Particulate Rate (kg/hr)	24,062	29,383	20,366	**24,604**
$E_{T/yr}$	Particulate Rate (Ton/yr)	232,389	283,776	196,695	**237,620**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	18.2366	22.3572	16.2793	**18.9577**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	17.9703	22.0125	16.1135	**18.6988**

RESULTS

Table 2-5:
Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		June 8	June 8	June 8	
Start Time (approx.)		09:26	13:03	15:50	
Stop Time (approx.)		11:53	15:15	18:03	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.6	5.0	5.1	**4.9**
CO_2	Carbon dioxide (dry volume %)	14.4	14.0	14.0	**14.1**
T_s	Sample temperature (°F)	330	333	335	**333**
B_w	Actual water vapor in gas (% by volume)	10.38	10.52	10.71	**10.54**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	1,044,290	1,042,578	1,044,756	**1,043,875**
Q_s	Volumetric flow rate, standard (scfm)	659,033	656,253	654,634	**656,640**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	590,652	587,193	584,546	**587,464**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	2.253E-02	1.723E-02	1.908E-02	**1.961E-02**
$E_{T/yr}$	Rate (Ton/yr)	9.867E-02	7.545E-02	8.358E-02	**8.590E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	8.001E-06	6.310E-06	7.065E-06	**7.125E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.910E-06	6.259E-06	6.964E-06	**7.044E-06**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	2.100E-02	1.640E-02	1.898E-02	**1.879E-02**
$E_{T/yr}$	Rate (Ton/yr)	9.199E-02	7.184E-02	8.312E-02	**8.232E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.459E-06	6.008E-06	7.027E-06	**6.831E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.375E-06	5.959E-06	6.926E-06	**6.753E-06**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	3.791E-04	4.405E-04	3.749E-05	**2.857E-04**
$E_{T/yr}$	Rate (Ton/yr)	1.660E-03	1.929E-03	1.642E-04	**1.251E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.346E-07	1.613E-07	1.388E-08	**1.033E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.331E-07	1.600E-07	1.368E-08	**1.023E-07**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	1.147E-03	3.843E-04	6.560E-05	**5.322E-04**
$E_{T/yr}$	Rate (Ton/yr)	5.023E-03	1.683E-03	2.873E-04	**2.331E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	4.073E-07	1.407E-07	2.429E-08	**1.908E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	4.027E-07	1.396E-07	2.394E-08	**1.887E-07**

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Jun 8	Jun 8	Jun 8	
Start Time (approx.)		09:00	11:59	14:52	
Stop Time (approx.)		11:14	14:12	17:02	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.2	5.4	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.7	13.9	13.6	**13.7**
T_s	Sample temperature (°F)	231	232	231	**232**
B_w	Actual water vapor in gas (% by volume)	14.16	14.36	14.15	**14.22**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	959,107	1,010,648	996,438	**988,731**
Q_s	Volumetric flow rate, standard (scfm)	734,258	772,458	762,561	**756,426**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	630,266	661,565	654,694	**648,841**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0008	0.0010	0.0012	**0.0010**
$E_{lb/hr}$	Particulate Rate (lb/hr)	4.0681	5.8250	7.0036	**5.6322**
$E_{kg/hr}$	Particulate Rate (kg/hr)	1.8449	2.6417	3.1762	**2.5543**
$E_{T/yr}$	Particulate Rate (Ton/yr)	17.8181	25.5135	30.6758	**24.6691**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0014	0.0019	0.0024	**0.0019**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0014	0.0019	0.0023	**0.0019**

RESULTS

Table 2-7:
Unit 2 – Stack - Fluoride

Run No.		1	2	3	Average
Date (2004)		Jun 9	Jun 9	Jun 9	
Start Time (approx.)		10:30	12:08	14:04	
Stop Time (approx.)		11:33	13:10	15:10	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,882	9,882	9,882	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,795	1,795	1,795	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.6	5.2	**5.4**
CO_2	Carbon dioxide (dry volume %)	14.2	14.0	14.5	**14.2**
T_s	Sample temperature (°F)	239	231	215	**228**
B_w	Actual water vapor in gas (% by volume)	14.80	14.99	15.30	**15.03**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	974,643	974,975	926,246	**958,621**
Q_s	Volumetric flow rate, standard (scfm)	738,273	746,631	725,948	**736,951**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	629,007	634,737	614,851	**626,198**
Hydrogen Fluoride (HF) Results					
C_{sd}	HF Concentration (ppmdv)	<0.1008	<0.0970	<0.0018	**<0.0665**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.1974	<0.1918	<0.0034	**<0.1309**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<6.969E-05	<6.797E-05	<1.221E-06	**<4.630E-05**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<6.612E-05	<6.456E-05	<1.149E-06	**<4.394E-05**

RESULTS

Table 2-8:
Unit 2 – Stack – Lead

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jun 8	Jun 8	Jun 8	
Start Time (approx.)		09:00	11:59	14:52	
Stop Time (approx.)		11:14	14:12	17:02	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.2	5.4	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.7	13.9	13.6	**13.7**
T_s	Sample temperature (°F)	231	232	231	**232**
B_w	Actual water vapor in gas (% by volume)	14.16	14.36	14.15	**14.22**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	959,107	1,010,648	996,438	**988,731**
Q_s	Volumetric flow rate, standard (scfm)	734,258	772,458	762,561	**756,426**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	630,266	661,565	654,694	**648,841**
Lead Results - Total					
C_{sd}	Concentration (lb/dscf)	<6.186E-11	<2.375E-11	<1.369E-11	**<3.310E-11**
$E_{lb/hr}$	Rate (lb/hr)	<2.339E-03	<9.426E-04	<5.380E-04	**<1.273E-03**
$E_{T/yr}$	Rate (Ton/yr)	<1.025E-02	<4.129E-03	<2.356E-03	**<5.577E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<8.188E-07	<3.103E-07	<1.813E-07	**<4.368E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<8.091E-07	<3.061E-07	<1.805E-07	**<4.319E-07**

RESULTS

Table 2-9:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		June 8	June 8	June 8	
Start Time (approx.)		09:00	13:03	15:50	
Stop Time (approx.)		11:42	15:15	18:02	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,817	9,817	9,817	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,792	1,792	1,792	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.8	6.0	5.7	**5.8**
CO_2	Carbon dioxide (dry volume %)	13.2	13.2	13.5	**13.3**
T_s	Sample temperature (°F)	226	227	228	**227**
B_w	Actual water vapor in gas (% by volume)	13.71	13.34	13.85	**13.64**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	961,886	969,765	981,726	**971,126**
Q_s	Volumetric flow rate, standard (scfm)	741,616	746,739	754,577	**747,644**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	639,907	647,113	650,047	**645,689**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<5.879E-04	<1.852E-03	<5.062E-04	**<9.821E-04**
$E_{T/yr}$	Rate (Ton/yr)	<2.575E-03	<8.113E-03	<2.217E-03	**<4.302E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<2.081E-07	<6.569E-07	<1.752E-07	**<3.467E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<2.079E-07	<6.476E-07	<1.723E-07	**<3.426E-07**
RE	Removal Efficiency (Fd-based, lb/MMBtu)	97.4%	89.7%	97.5%	**94.9%**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<2.100E-05	<2.081E-05	<2.109E-05	**<2.097E-05**
$E_{T/yr}$	Rate (Ton/yr)	<9.197E-05	<9.115E-05	<9.238E-05	**<9.183E-05**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.431E-09	<7.381E-09	<7.299E-09	**<7.370E-09**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.424E-09	<7.277E-09	<7.178E-09	**<7.293E-09**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<4.199E-05	1.145E-04	4.429E-04	**<1.998E-04**
$E_{T/yr}$	Rate (Ton/yr)	<1.839E-04	5.013E-04	1.940E-03	**<8.751E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<1.486E-08	4.060E-08	1.533E-07	**<6.958E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<1.485E-08	4.002E-08	1.507E-07	**<6.854E-08**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	5.564E-04	1.727E-03	5.273E-05	**7.788E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.437E-03	7.566E-03	2.310E-04	**3.411E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.969E-07	6.126E-07	1.825E-08	**2.759E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.967E-07	6.040E-07	1.795E-08	**2.729E-07**

[1] A less than symbol (<) indicates that one or more factions were below the laboratory minimum detection limit.

RESULTS

Table 2-10:
Unit 2 – Stack - Ammonia

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jun 9	Jun 9	Jun 9	
Start Time (approx.)		12:25	13:41	15:14	
Stop Time (approx.)		13:27	14:54	16:21	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,882	9,882	9,882	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,795	1,795	1,795	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.6	5.4	5.2	**5.4**
CO_2	Carbon dioxide (dry volume %)	14.0	14.3	14.2	**14.2**
T_s	Sample temperature (°F)	224	214	212	**217**
B_w	Actual water vapor in gas (% by volume)	14.42	14.48	14.25	**14.39**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	986,624	908,645	903,817	**933,028**
Q_s	Volumetric flow rate, standard (scfm)	760,646	713,209	712,324	**728,726**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	650,930	609,910	610,786	**623,876**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	0.5292	0.4454	<0.5870	**<0.5206**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	0.9131	0.7201	<0.9504	**<0.8612**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	3.9993	3.1541	<4.1628	**<3.7721**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	0.0003	0.0003	<0.0003	**<0.0003**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	0.0003	0.0002	<0.0003	**<0.0003**

DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

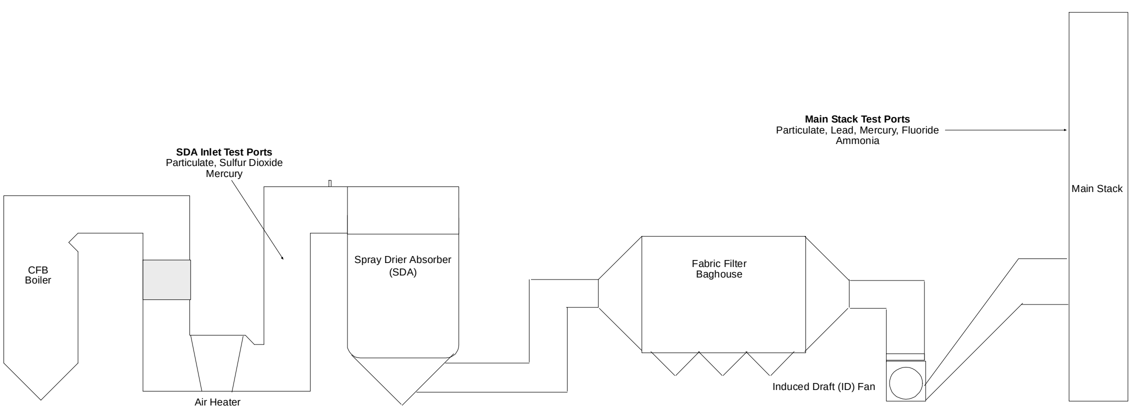


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

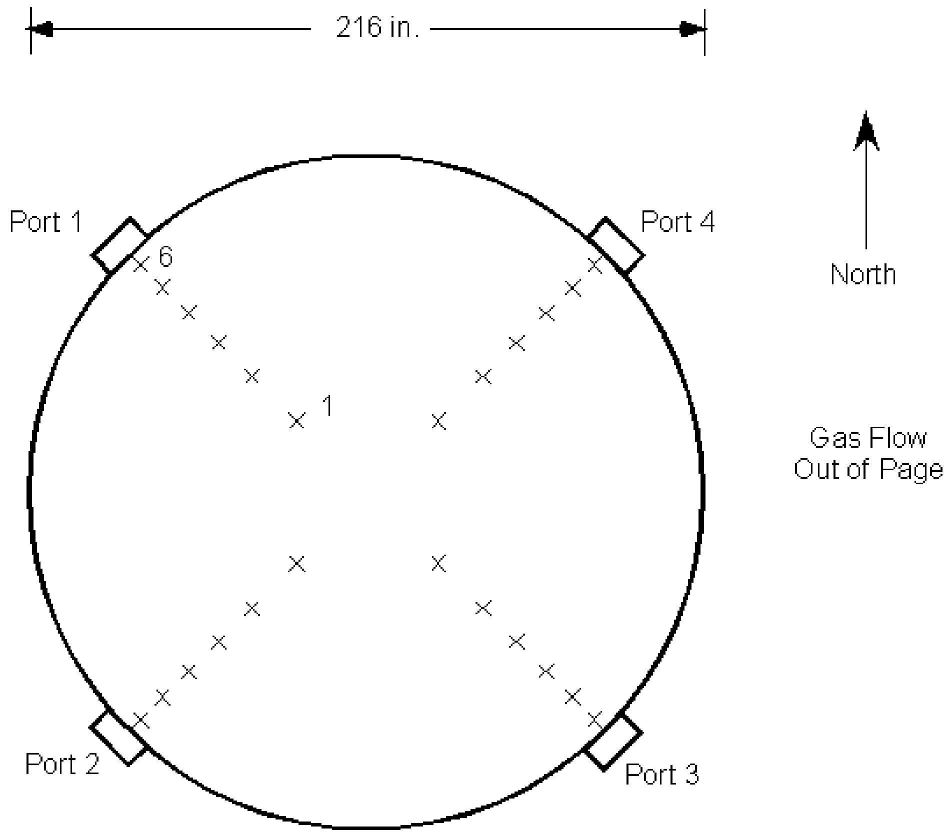
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-7	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-6	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-3	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-3	4	3	5	60	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-3	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



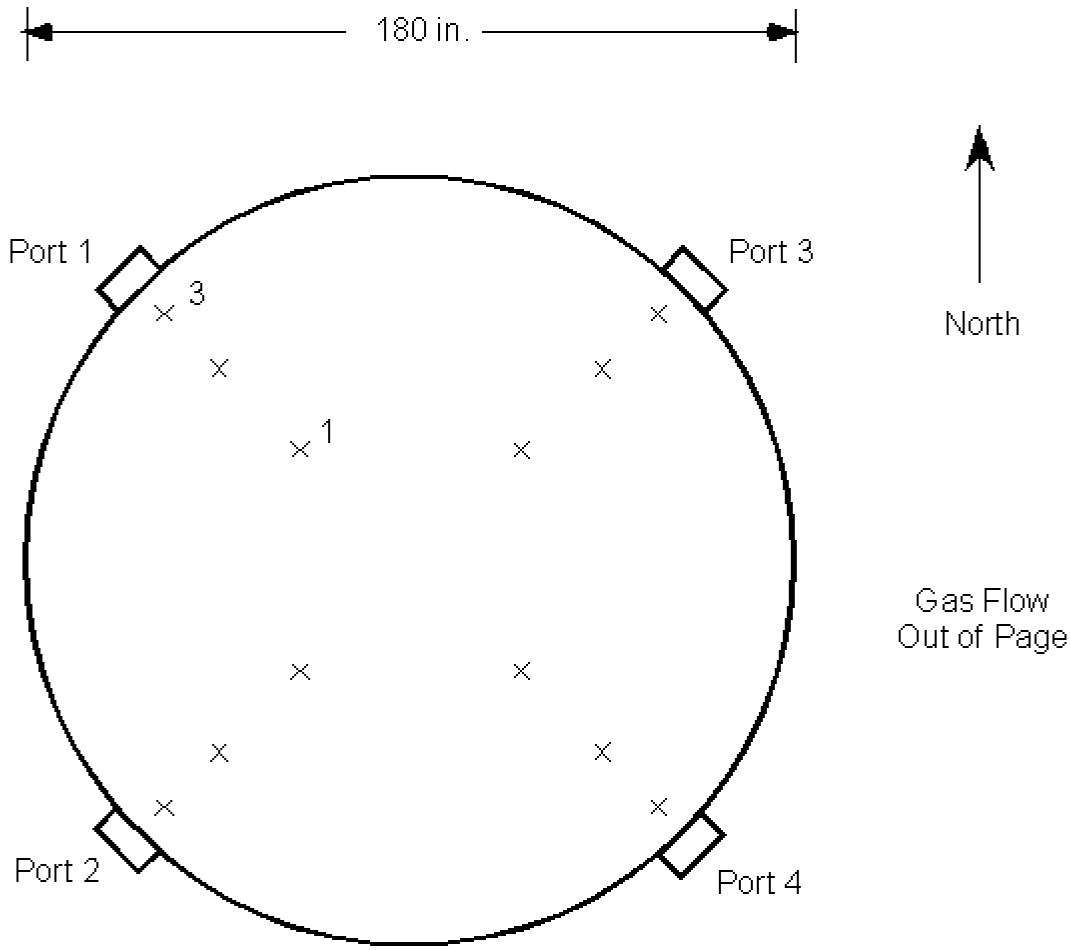
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 — Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 — Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 23, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

Title 40 CFR Part 60 Appendix A	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 23	"Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources"
Method 29	"Determination of Metals Emissions from Stationary Sources"
Conditional Test Method	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
Draft Methods	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Hydro Ontario Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY PI DATA

		Date:	June 8, 2004	June 9, 2004
		Start:	1130 hours	1000 hours
		End:	1530 hours	1600 hours
Substance	**Characteristic Being Measured**	**Values Used in Efficiency Calculation**		
Primary Air	Avg. Out A and B, Deg F		127.19	129.49
	Average, deg F		103.21	103.29
	Count		480.00	422.00
	Standard Deviation		3.87	4.41
Secondary Air	Total SA flow, klb/hr		0.83	0.79
	Average, Total SA Flow, klb/hr		0.14	0.14
	Count		240.00	211.00
	Standard Deviation		0.09	0.09
	Avg. Out A and B, Deg F		118.99	126.49
	Average, deg F		99.16	99.28
	Count		480.00	422.00
	Standard Deviation		5.07	5.61
Fuel	Total Flow, klb/hr		236.33	232.57
	Average, deg F		232.73	232.62
	Count		240.00	211.00
	Standard Deviation		1.12	0.31
PAHTR Gas Out	Gas Out, deg F, A train		317.18	333.82
	Gas Out, deg F, B train		325.79	342.60
	Average, deg F		324.71	333.19
	Count		480.00	422.00
	Standard Deviation		5.17	6.46
SAHTR Gas Out	Gas Out, deg F, A train		290.45	311.72
	Gas Out, deg F, B train		302.04	326.82
	Average, deg F		301.43	311.94
	Count		480.00	422.00
	Standard Deviation		11.67	12.91
PAH Gas In	Gas In, deg F, A & B train		564.06	602.21
	Average, deg F		567.43	582.31
	Count		240.00	211.00
	Standard Deviation		1.57	13.15
SAH Gas In	Gas In, deg F A & B train		566.74	604.68
	Average, deg F		570.20	584.28
	Count		240.00	211.00
	Standard Deviation		1.56	13.01
PAH Air Out	Air Out, deg F A & B train		465.98	494.35
	Average, deg F		469.16	481.81
	Count		240.00	211.00
	Standard Deviation		1.31	9.49

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
SA Airheater Air Out	Air Out, deg F A & B train	423.62	457.91
	Average, deg F	428.61	446.98
	Count	240.00	211.00
	Standard Deviation	3.73	8.47
Stripper/ Coolers - A, B, C, D	Ash leaving temperature, deg F, A	270.70	318.54
	Ash leaving temperature, deg F, B	115.46	116.68
	Ash leaving temperature, deg F, C	129.20	463.75
	Ash leaving temperature, deg F, D	281.80	436.20
	Average, deg F	305.42	368.08
	Count	480.00	422.00
	Standard Deviation	12.82	88.02
SDA Hopper	Temperature, deg F		
	Average, deg F	158.46	181.67
	Count	240.00	211.00
	Standard Deviation	6.80	6.40
Limestone Feed Rate 1	Feedrate, feeders 1, 2, 3, lb/hr	56,622.52	57,116.93
	Average, lb/hr	64,005.39	59,301.70
	Count	240.00	211.00
	Standard Deviation	7.45	5.76
SO2, in flue Gas	AH inlet, ppm		
	Average, ppm mv	41.09	30.65
	Count	240.00	211.00
	Standard Deviation	24.86	19.49
Intrex Blower Air Flow	Flow to A, B, C, lb/hr	44,334.18	44,204.36
	Average, lb/hr	43,360.97	44,624.64
	Count	1,440.00	1,266.00
	Standard Deviation	373.51	193.54
Intrex Seal Pot Blower	PA Flow to Intrex A, B, C, lb/hr	36,792.76	36,972.43
	Average, lb/hr	36,539.68	37,620.46
	Count	240.00	211.00
	Standard Deviation	280.55	336.88
Intrex Blower Exit Air Temp	Average, deg F	181.91	182.58
	Count	240.00	211.00
	Standard Deviation	4.15	1.81
Seal Pot Blower Exit Air Temp	Average, deg F	200.11	201.76
	Count	240.00	211.00
	Standard Deviation	2.87	1.95
Feedwater Temperature to Econ	Average, deg F	484.13	484.77
	Count	240.00	211.00
	Standard Deviation	0.65	0.97
Feedwater Pressure to Econ	Average, psig	1,950.46	1,950.48
	Count	240.00	211.00
	Standard Deviation	9.29	7.66

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
(DSH)SH-1 Spray Flow	Average, lb/hr	1,259.08	2,331.04
	Count	240.00	211.00
	Standard Deviation	0.89	1.70
SH-1 Spray Temperature	Average, deg F	313.78	317.58
	Count	240.00	211.00
	Standard Deviation	1.05	1.85
SH-1 Spray Pressure	Average, psig	2,727.50	2,718.56
	Count	240.00	211.00
	Standard Deviation	5.42	4.47
Drum Pressure	Average of three pressure values, psig	2,600.83	2,580.15
	Average, psig	2,588.08	2,580.00
	Count	720.00	633.00
	Standard Deviation	6.58	5.38
Main Steam Temperature	Average, deg F	998.03	999.81
	Count	240.00	211.00
	Standard Deviation	2.81	2.12
Main Steam Pressure	Average of two pressure values, psig	2,411.87	2,399.54
	Average, psig	2,400.20	2,400.50
	Count	480.00	422.00
	Standard Deviation	5.63	4.01
Reheater Outlet Temperature	Average of three temp values, deg F	1,005.56	1,006.09
	Average, deg F	1,004.75	1,011.72
	Count	720.00	633.00
	Standard Deviation	3.08	1.98
Reheater Outlet Pressure	Average of two pressure values, psig	580.57	569.42
	Average, psig	571.53	573.77
	Count	480.00	422.00
	Standard Deviation	25.22	25.76
CRH Ent Attemp Temp	Average, deg F	601.75	588.07
	Count	240.00	211.00
	Standard Deviation	1.33	11.01
CRH Ent Attemp Press	Average, psig	570.89	573.08
	Count	240.00	211.00
	Standard Deviation	4.64	7.02
RH Spray Flow	Average, lb/hr	119.91	9,339.18
	Count	240.00	211.00
	Standard Deviation	0.07	10.33
RH Spray Temp	Average, deg F	312.27	333.42
	Count	240.00	211.00
	Standard Deviation	0.51	3.70

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
RH Spray Pressure	Average, psig	945.12	851.91
	Count	240.00	211.00
	Standard Deviation	2.17	99.27
Htr 1 FW Entering Temp	Data	419.00	418.21
	Data	485.08	484.01
	Average, deg F	451.07	451.88
	Count	480.00	422.00
	Standard Deviation	33.10	32.95
Htr 1 FW Entering Pressure	Data	1,957.90	1,964.61
	Data	1,957.90	1,964.61
	Average, psig	1,950.46	1,950.48
	Count	480.00	422.00
	Standard Deviation	9.28	7.65
Htr 1 FW Leaving Temp	Average, deg F	484.13	484.77
	Count	240.00	211.00
	Standard Deviation	0.65	0.97
Htr 1 FW Leaving Pressure	Average, psig	1,950.46	1,950.48
	Count	240.00	211.00
	Standard Deviation	9.29	7.66
Htr 1 Extraction Stm Temp	Average, deg F	627.60	631.57
	Count	240.00	211.00
	Standard Deviation	1.56	1.86
Htr 1 Extraction Stm Pressure	Average, psig	573.83	576.51
	Count	240.00	211.00
	Standard Deviation	4.50	6.91
Htr 1 Drain Temp	Average, deg F	423.28	424.08
	Count	240.00	211.00
	Standard Deviation	0.58	0.92
Htr 1 Drain Pressure	Average, psig	573.83	576.51
	Count	240.00	211.00
	Standard Deviation	4.50	6.91
Feedwater to Econ	Pressure, psig	1,957.90	1,964.61
	Temperature, deg F	485.08	484.01
	Density, lb / cu. ft.	50.38	50.43
Primary Air to SC A	Total of three flow values, lb/hr	32,007.69	32,773.35
	Average, k lb/hr	33,142.63	33,542.34
	Count	240.00	211.00
	Standard Deviation	1.32	1.08
Primary Air to SC B	Total of three flow values, lb/hr	7,798.89	7,426.83
	Average, lb/hr	7,444.43	7,875.16
	Count	240.00	211.00
	Standard Deviation	0.15	0.29

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air to SC C	Total of three flow values, lb/hr	15,445.22	19,346.09
	Average, lb/hr	14,857.70	18,921.61
	Count	240.00	211.00
	Standard Deviation	0.26	0.41
Primary Air to SC D	Total of three flow values, lb/hr	33,256.10	35,647.35
	Average, lb/hr	35,165.13	35,695.59
	Count	240.00	211.00
	Standard Deviation	1.75	0.80
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values, lb/hr	1,045,784.54	1,046,699.63
	Average, lb/hr	1,056,665.39	1,053,967.82
	Count	240.00	211.00
	Standard Deviation	153.58	131.47
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values, lb/hr	34,510.33	36,149.94
	Average, lb/hr	34,440.37	35,914.11
	Count	240.00	211.00
	Standard Deviation	0.26	0.20
Total air Flow, klb/hr	Average, lb/hr	2,447,151.01	2,437,159.84
	Count	240.00	211.00
	Standard Deviation	12.20	5.72

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve SA330	Below Turbine	closed	closed	closed	closed

#1 Heater shell Drain leaking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

Hole #	Description	Approximate Location	Temp Check
24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain Heat Soak Valve	Below Turbine	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - Illinois 6 Coal

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY - FUEL ANALYSES

Fuel	Test #3		June 8 - 9, 2004		
Lab Number	71-237672	71-237673	Average	Count	Std Deviation
Date	8-Jun-04	9-Jun-04			
Time	4 hours	4 hours			
Proximate Analysis					
Moisture, wt%	12.10	12.19	12.15	2	0.06
Ash, wt%	7.08	6.59	6.84	2	0.35
Volatile, wt%	34.77	34.61	34.69	2	0.11
Fixed Carbon, wt%	46.05	46.61	46.33	2	0.40
Ultimate Analysis					
Carbon, wt%	64.93	64.70	64.82	2	0.16
Hydrogen, wt%	4.31	4.57	4.44	2	0.18
Nitrogen, wt%	1.27	1.26	1.27	2	0.01
Sulfur, wt%	3.17	3.32	3.25	2	0.11
Moisture, wt%	12.10	12.19	12.15	2	0.06
Ash, wt%	7.08	6.59	6.84	2	0.35
Oxygen, wt%	7.14	7.37	7.26	2	0.16
Higher Heating, Btu/lb	11,649	11,664	11656.50	2	10.61
Total Chlorine, wt%	0.15	0.15	0.15	2	0.00
Total Fluorine, wt%	67.00	62.00	64.50	2	3.54
Total Mercury, ug/g	0.050	0.040	0.05	2	0.01
Total Lead, ug/g	12.000	12.000	12.00	2	0.00
Moisture (oven), wt%	12.10	12.19	12.15	2	0.06
Mineral analysis					
SiO_2, wt%	46.61	46.12	46.37	2	0.35
Al_2O_3, wt%	19.47	19.03	19.25	2	0.31
Ti_2O, wt%	1.10	1.06	1.08	2	0.03
Fe_2O_3, wt%	23.22	23.05	23.14	2	0.12
CaO, wt%	2.63	2.84	2.74	2	0.15
MgO, wt%	0.79	0.74	0.77	2	0.04
K_2O, wt%	2.31	2.16	2.24	2	0.11
Na_2O, wt%	0.70	0.68	0.69	2	0.01
SO_3, wt%	2.23	3.10	2.67	2	0.62
P_2O_5, wt%	0.16	0.16	0.16	2	0.00
SrO, wt%	0.03	0.03	0.03	2	0.00
BaO, wt%	0.03	0.04	0.04	2	0.01
Mn_3O_4, wt%	0.04	0.04	0.04	2	0.00
Undetermined, wt%	0.68	0.95	0.82	2	0.19
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	14.97	14.53	14.75	2	0.31
Particulate Left Mesh, 1/4", wt%	33.41	33.29	33.35	2	0.08
Particulate Left Mesh, #4, wt%	37.48	37.29	37.39	2	0.13
Particulate Left Mesh, #8, wt%	55.21	55.49	55.35	2	0.20
Particulate Left Mesh, #14, wt%	71.47	71.85	71.66	2	0.27
Particulate Left Mesh, #28, wt%	82.16	83.87	83.02	2	1.21
Particulate Left Mesh, #50, wt%	87.37	88.13	87.75	2	0.54
Particulate Left Mesh, #100, wt%	92.51	93.06	92.79	2	0.39
Bottom, wt%	7.49	6.94	7.22	2	0.39

ATTACHMENT H

Limestone Analyses

JEA Northside Unit 2
Test #2-50/50 Blend
SUMMARY LIMESTONE ANALYSES

January 27, 2004

Limestone	Test #3			June 8 - 9, 2004		
Lab number	71-237674	71-237675		Average	Count	Std Deviation
Date	8-Jun-04	9-Jun-04				
Time	4 hours	4 hours				
Inerts, wt%	2.07	1.84		1.955	2	0.16263456
CaCO3, wt%	96.59	96.77		96.68	2	0.12727922
MgCO3, wt%	1.34	1.39		1.365	2	0.03535534
Moisture, %	0.16	0.22		0.19	2	0.04242641
Na, ug/g	70.00	72.00		71	2	1.41421356
K, ug/g	90.00	90.00		90	2	0
Pb, ug/g	11.00	12.00		11.5	2	0.70710678
Hg, ug/g	0.040	0.060		0.05	2	0.01414214
F, ug/g	60.00	46.00		53	2	9.89949494
Cl, ug/g	110.000	105.000		107.5	2	3.53553391
Particulate size distribution						
Particulate Left Mesh, #8, wt%	26.13	15.45		20.79	2	7.55190042
Particulate Left Mesh, #14, wt%	13.58	8.56		11.07	2	3.54967604
Particulate Left Mesh, #28, wt%	16.09	11.33		13.71	2	3.36582828
Particulate Left Mesh, #48, wt%	9.57	10.48		10.025	2	0.64346717
Particulate Left Mesh, #100, wt%	13.41	20.79		17.1	2	5.21844805
Bottom, wt%	21.22	33.39		27.305	2	8.60548953
Calcium Carbonate Equivalent	98.18	98.42		98.3	2	0.16970563

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Test #3			June 8 - 9, 2004		
Lab Number	71-237680	71-237681		Average	Count	Std Deviation
Date	8-Jun-04	9-Jun-04				
Time	4 hours	4 hours				
Unburned carbon, wt%	1.26	1.42		1.34	2	0.1131
Organic carbon, wt%	0.65	1.05		0.85	2	0.2828
Loss on Ignition @ 950 deg F	5.11	3.66		4.39	2	1.0253
CaSO4, %wt	43.69	47.58		45.64	2	2.7506
Sulfur, wt%	10.40	11.32		10.86	2	0.6505
Mineral analysis						
SiO2, wt%	3.14	3.89		3.52	2	0.5303
SO3, wt%	25.98	28.28		27.13	2	1.6263
Fe2O3, wt%	0.97	1.40		1.19	2	0.3041
CaO, wt%	59.43	58.92		59.18	2	0.3606
MgO, wt%	0.86	0.81		0.84	2	0.0354
Na2O, wt%	0.01	0.02		0.02	2	0.0071
K2O, wt%	0.05	0.04		0.05	2	0.0071
Al2O3, %wt	1.83	1.90		1.87	2	0.0495
TiO2, %wt	0.13	0.16		0.15	2	0.0212
P2O5, %wt	0.05	0.02		0.04	2	0.0212
SrO, %wt	0.10	0.09		0.10	2	0.0071
BaO, %wt	0.01	0.01		0.01	2	0.0000
Mn3O2, %wt	0.01	0.01		0.01	2	0.0000
Undetermined, %wt	7.43	4.45		5.94	2	2.1072
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	0.00	0.00		0.00	2	0.0000
Particulate Left Mesh, 1/4", wt%	0.42	0.00		0.21	2	0.2970
Particulate Left Mesh, #4, wt%	0.26	0.98		0.62	2	0.5091
Particulate Left Mesh, #8, wt%	4.34	4.53		4.44	2	0.1344
Particulate Left Mesh, #14, wt%	8.54	9.41		8.98	2	0.6152
Particulate Left Mesh, #28, wt%	20.85	15.61		18.23	2	3.7052
Particulate Left Mesh, #48, wt%	20.37	25.88		23.13	2	3.8962
Particulate Left Mesh, #100, wt%	25.02	24.04		24.53	2	0.6930
Bottom, wt%	20.20	19.55		19.88	2	0.4596

ATTACHMENT J

Fly Ash (Air Heater and PJFF) Analyses

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY - FLY ASH ANALYSES

Fly Ash	June 8 - 9, 2004 Air Heater			June 8 - 9, 2004 Air Heater (Iso Kinetic)		
	Average	Count	Std Deviation	Average	Count	Std Deviation
Unburned carbon, wt%	3.88	2	1.9940	6.79	2	0.6788
Organic carbon, wt%	2.94	2	1.3435	5.46	2	1.1031
LOI @ 1742 °F (950 °C)	6.81	2	4.6386	11.92	2	0.5445
CaSO4, wt%	43.20	2	5.4377	25.53	2	1.2233
Sulfur, wt%	10.28	2	1.3081	6.08	2	0.3677
Ash analysis						
SiO2, wt%	8.40	2	0.7354	14.37	2	0.0636
Al2O3, wt%	3.46	2	0.3111	6.02	2	0.0778
TiO2, wt%	0.18	2	0.0000	0.29	2	0.0071
Fe2O3, wt%	6.25	2	0.5303	5.68	2	0.7142
CaO, wt%	47.63	2	2.5244	43.55	2	0.2758
MgO, wt%	0.70	2	0.0354	0.67	2	0.0000
K2O, wt%	0.24	2	0.0424	0.76	2	0.0212
Na2O, wt%	0.02	2	0.0000	0.19	2	0.0071
SO2, wt%	25.69	2	3.2668	15.19	2	0.9192
P2O5, wt%	0.03	2	0.0000	0.03	2	0.0000
SrO, wt%	0.07	2	0.0000	0.07	2	0.0071
BaO, wt%	0.03	2	0.0212	0.01	2	0.0000
Mn3O4, wt%	0.02	2	0.0000	0.01	2	0.0000
Undetermined	7.30	2	4.2285	13.20	2	0.0990
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	2	0.0000	0.00	2	0.0000
Particulate Left Mesh, #14, wt%	0.03	2	0.0354	0.00	2	0.0000
Particulate Left Mesh, #28, wt%	0.07	2	0.0990	0.00	2	0.0000
Particulate Left Mesh, #48, wt%	0.12	2	0.0283	0.00	2	0.0000
Particulate Left Mesh, #100, wt%	0.17	2	0.0990	0.36	2	0.0707
Bottom, wt%	99.62	2	0.2616	99.64	2	0.0707

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY - FLY ASH ANALYSES

Fly Ash	June 8 - 9, 2004 Bag House		
	Average	Count	Std Deviation
Unburned carbon, wt%	6.89	2	0.3253
Organic carbon, wt%	5.63	2	0.5798
LOI @ 1742 °F (950 °C)	13.27	2	0.3182
CaSO4, wt%	25.01	2	0.6930
Sulfur, wt%	6.57	2	0.0849
Ash analysis			
SiO2, wt%	15.12	2	0.7990
Al2O3, wt%	6.35	2	0.2970
TiO2, wt%	0.31	2	0.0071
Fe2O3, wt%	4.68	2	0.7354
CaO, wt%	41.98	2	2.4112
MgO, wt%	0.69	2	0.0000
K2O, wt%	0.79	2	0.0707
Na2O, wt%	0.23	2	0.0212
SO2, wt%	16.35	2	0.2121
P2O5, wt%	0.02	2	0.0000
SrO, wt%	0.06	2	0.0000
BaO, wt%	0.01	2	0.0000
Mn3O4, wt%	0.02	2	0.0000
Undetermined	13.41	2	0.2687
Particulate size distribution			
Particulate Left Mesh, #4, wt%	0.00	2	0.0000
Particulate Left Mesh, #14, wt%	0.00	2	0.0000
Particulate Left Mesh, #28, wt%	0.00	2	0.0000
Particulate Left Mesh, #48, wt%	0.00	2	0.0000
Particulate Left Mesh, #100, wt%	0.05	2	0.0707
Bottom, wt%	99.95	2	0.0707

ATTACHMENT K

Ambient Data, June 8, 2004 & June 9, 2004

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY MET DATA

	Date:	June 8, 2004	June 9, 2004
	Start:	1130 hours	1000 hours
	End:	1530 hours	1600 hours

Characteristic Being Measured	Values Used in Efficiency Calculation	
Dry Bulb Temperature, North / South, deg F	84.26	83.46
Count	952	960
Standard Deviation	3.83	3.15
Wet Bulb Temperature, North / South, deg F	74.56	75.04
Count	952	960
Standard Deviation	1.21	0.75
Atmospheric Pressure, in Hg	30.14	30.24
Atmospheric Pressure, psia	14.75	14.80
Count	7	6
Standard Deviation	0.01	0.01

ATTACHMENT L

Partial Loads Ambient Data, June 8, 2004, & June 9, 2004

JEA Northside Unit 2
Test #3
Illinois 6 Coal
SUMMARY - MET DATA, JUNE 8, 9, 2004

Date	Time (hrs)	Temperature, deg F (dry bulb)	Temperature, deg F (wet bulb) Calculated	Dew Point, deg F	Relative Humidity, %	Pressure, in Hg	Pressure, psiA	RH calc to determine wet bulb
JUNE 9, 2004 (80% LOAD TEST)								
9-Jun-04	1956	78.1	76.80	75.9	93	30.06	14.71	93
9-Jun-04	2056	77.0	76.00	75.0	94	30.08	14.72	94
9-Jun-04	2156	77	76.00	75.0	94	30.10	14.73	94
9-Jun-04	2256	75.0	74.30	73.9	96	30.11	14.74	96
9-Jun-04	2356	75.9	74.80	73.9	94	30.10	14.73	94
JUNE 8, 2004 (60% LOAD TEST)								
8-Jun-04	0056	72.0	71.50	71.1	97	30.14	14.75	97
8-Jun-04	0156	72.0	72.00	72.0	100	30.12	14.74	100
8-Jun-04	0256	71.1	71.10	71.1	100	30.11	14.74	100
8-Jun-04	0356	70.0	69.50	69.1	97	30.11	14.74	97
8-Jun-04	0456	70.0	69.50	69.1	97	30.12	14.74	97
JUNE 9, 2004 (40% LOAD TEST)								
9-Jun-04	0056	75.9	74.30	73.0	91	30.17	14.76	91
9-Jun-04	0156	75.0	74.00	73.0	94	30.16	14.76	94
9-Jun-04	0256	75.9	74.40	73.0	91	30.13	14.74	91
9-Jun-04	0356	73.9	73.40	73.0	97	30.11	14.74	97
9-Jun-04	0456	75.0	74.00	73.0	94	30.11	14.74	94

FIGURES

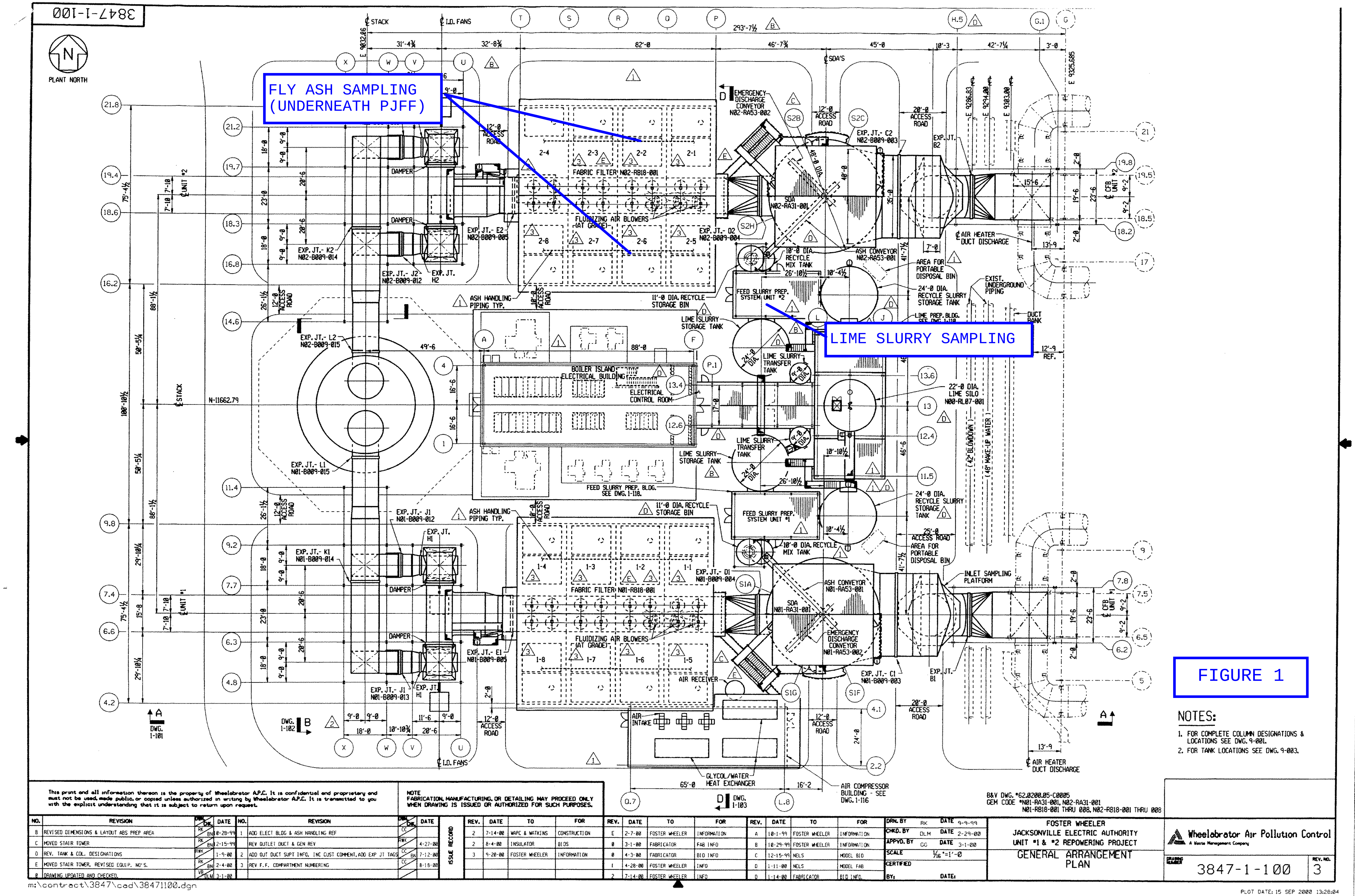
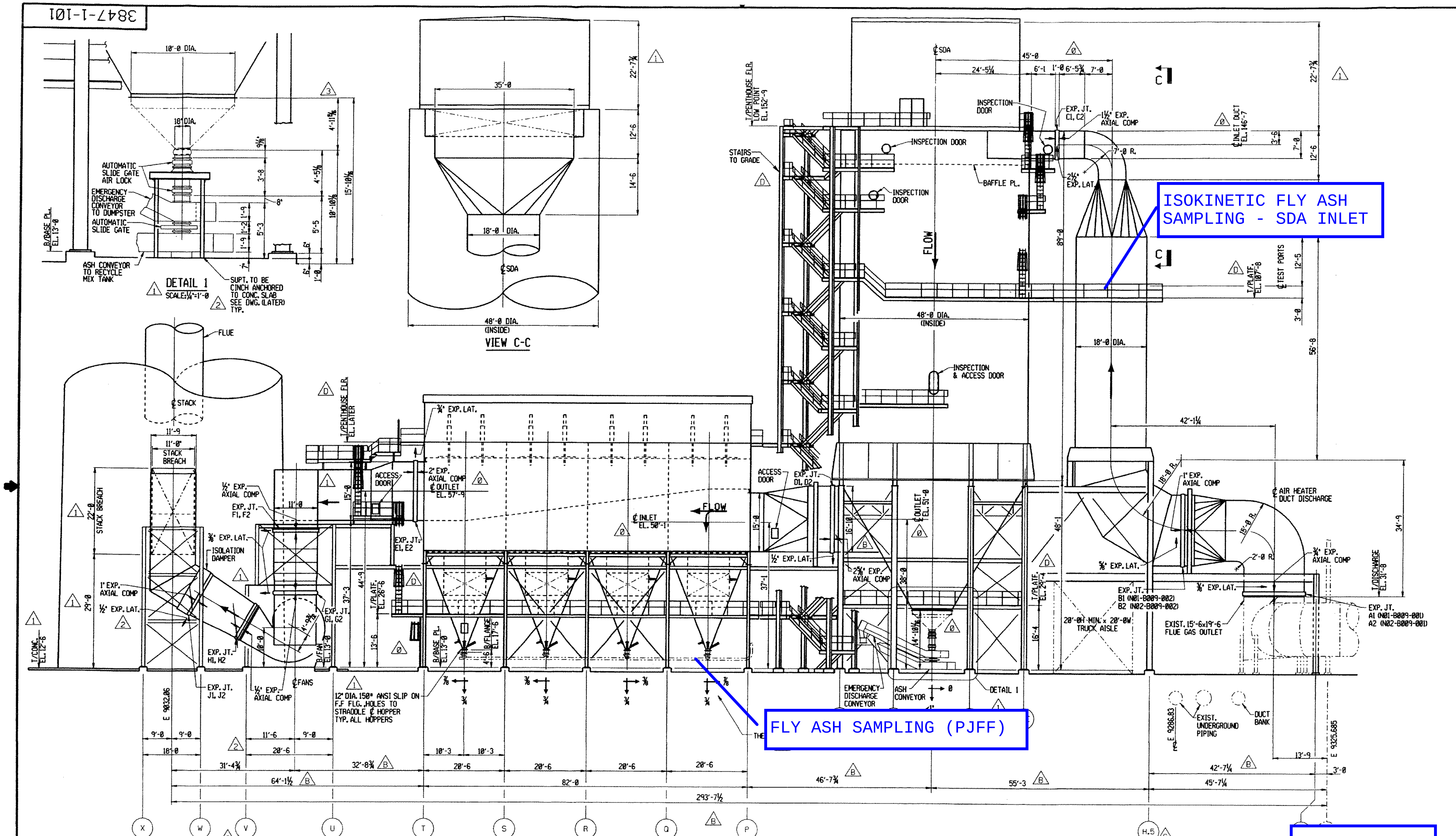


FIGURE 1

DWG40998 03-MAR-2004 14:48:45

P062713.62.0200.05-C0005 St:NE 11/21/00 MM-01186

DWG40998 03-MAR-2004 14:47:11



ELEVATION A-A
(3847-1-100)

FIGURE 2

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B&V DWG. #62.0200.05-C0006
GEM CODE #N01-RA31-001, N02-RA31-001
N01-RB18-001 THRU 008, N02-RB18-001 THRU 008

NO.	REVISION	DRN./CHK.	DATE
B	REVISED DIMENSIONS & TRUCK AISLE	RK / BN	0-28-99
C	REVISED COLUMN DESIGNATION	RK / BN	1-9-00
D	REVISED ACCESS ADDED ELEVATIONS	RK / BN	2-4-00
0	DWG UPDATED AND CHECKED	RWK / DM	3-1-00
1	REV DUCT DIM & ADD DETAIL 1	CC	

NO.	REVISION	DRN./CHK.	DATE
1	REVISED OUTLET DUCT & GENERAL REV.	RWK	4-27-00
2	ADD OUTLET DUCT SUPT INFO & INCORPORATE CUSTOMER COMMENT		
	ADD EXP MOVEMENTS AND EXP JT TAGS	CC / BN	7-12-00
3	REV. DIMENSIONS AT DETAIL 1	CC	7-19-00

ISSUE RECORD

REV.	DATE	TO	FOR
3	8-4-00	INSULATOR	BIDS
3	9-20-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
D	2-7-00	FOSTER WHEELER	INFORMATION
0	3-1-00	FABRICATOR	FAB INFO
1	4-28-00	FOSTER WHEELER	INFO
2	7-14-00	FOSTER WHEELER	INFO
2	7-14-00	WAPC & WATKINS	CONSTRUCTION

REV.	DATE	TO	FOR
A	10-1-99	FOSTER WHEELER	INFORMATION
B	10-29-99	FOSTER WHEELER	INFORMATION
B	12-15-99	NELS	MODEL BID
B	1-11-00	NELS	MODEL FAB
C	1-14-00	FABRICATOR	BID INFO.

DRN. BY	RK	DATE	9-9-99
CHKD. BY	DLM	DATE	2-29-00
APPVD. BY	CG	DATE	3-1-00
SCALE	3/32"=1'-0		
CERTIFIED			
BY:		DATE:	

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

GENERAL ARRANGEMENT
ELEVATION

Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-1-101
REV. NO. 3

m:\contract\3847\cad\38471101.dgn

PLOT DATE: 15 SEP 2000 13:28:26
LAST PLOTTED BY:RK

P062713.62.0200.05-C0006 St:NE 11/21/00 MM-01186

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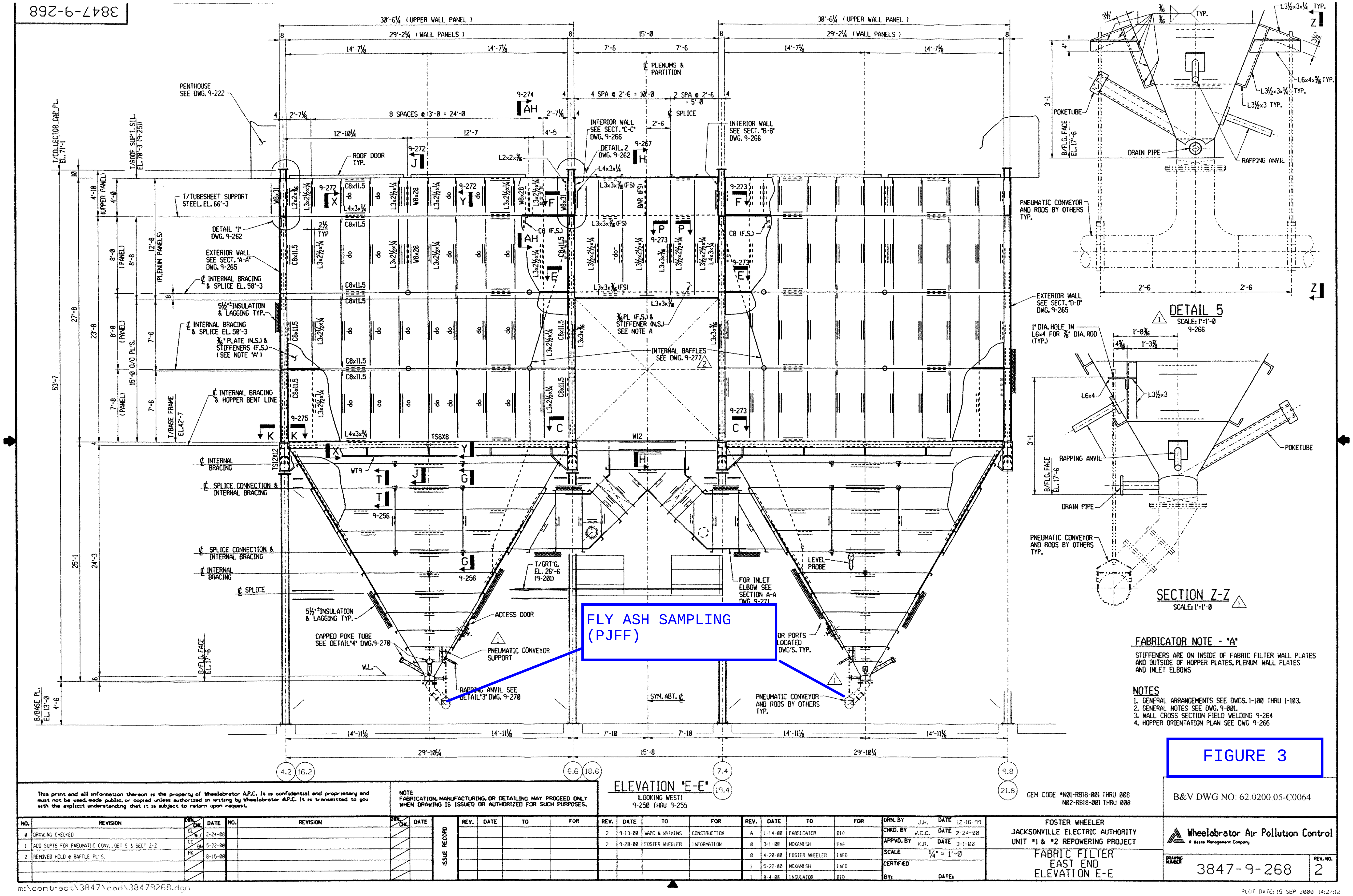

FIGURE 3

B&V DWG NO: 62.0200.05-C0064

P062713.62.0200.05-C0064 St:NE 11/21/00 MM-01179

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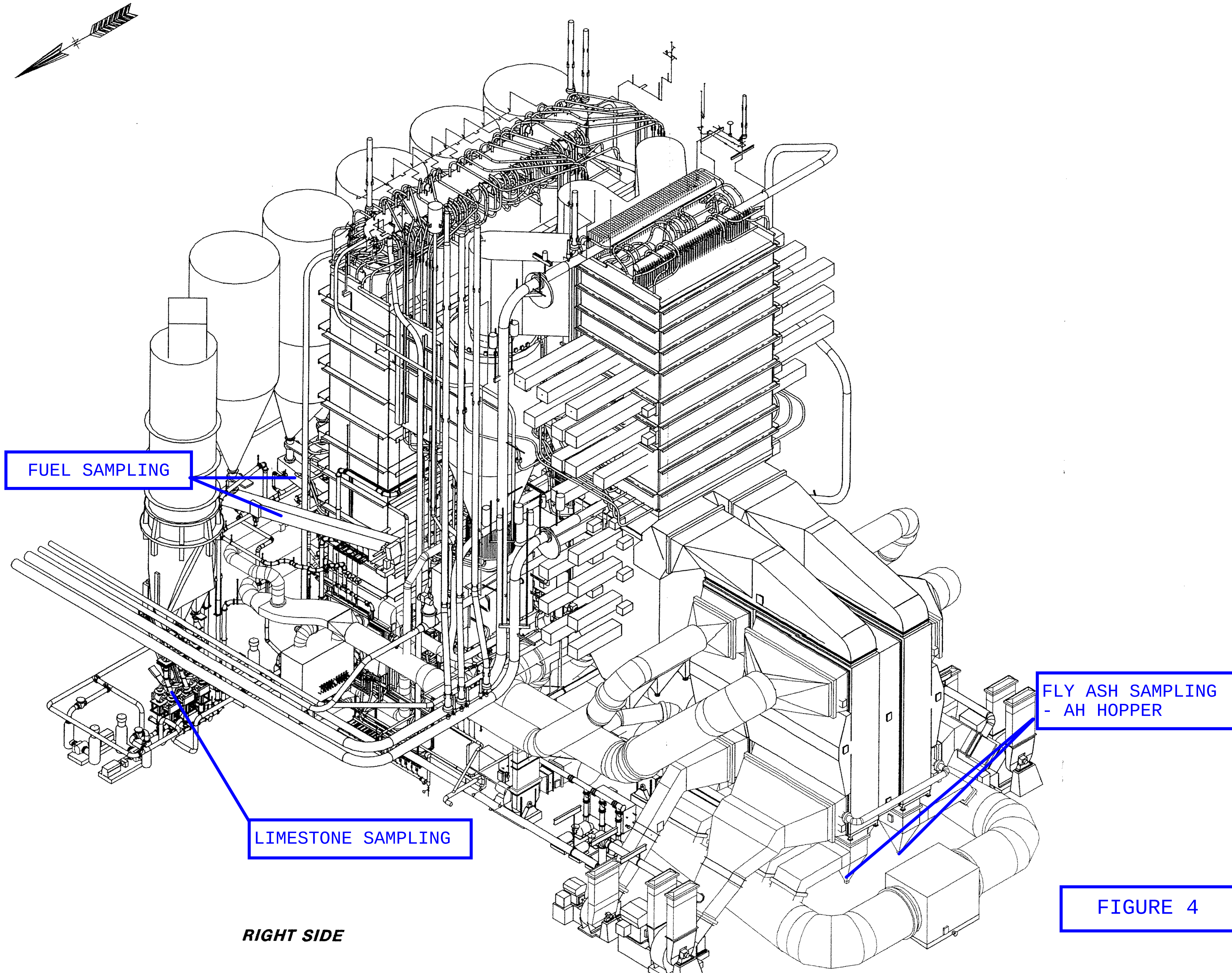


FIGURE 4

NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. FOR ADDITIONAL NOTES & REFERENCE DRAWINGS SEE DRAWING 43-7587-5-50

B&V Dwg No: 62.3401.05-C0012

REV.	DATE	DR.	DESCRIPTION
C	6-23-00	JHM	UPDATED DRAWING
B	5-26-99	JHM	DESIGN UPDATE
A	3-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
ISO VIEW (RIGHT SIDE)

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.:
B&V Drawing No.: 62.3401.05-C0012

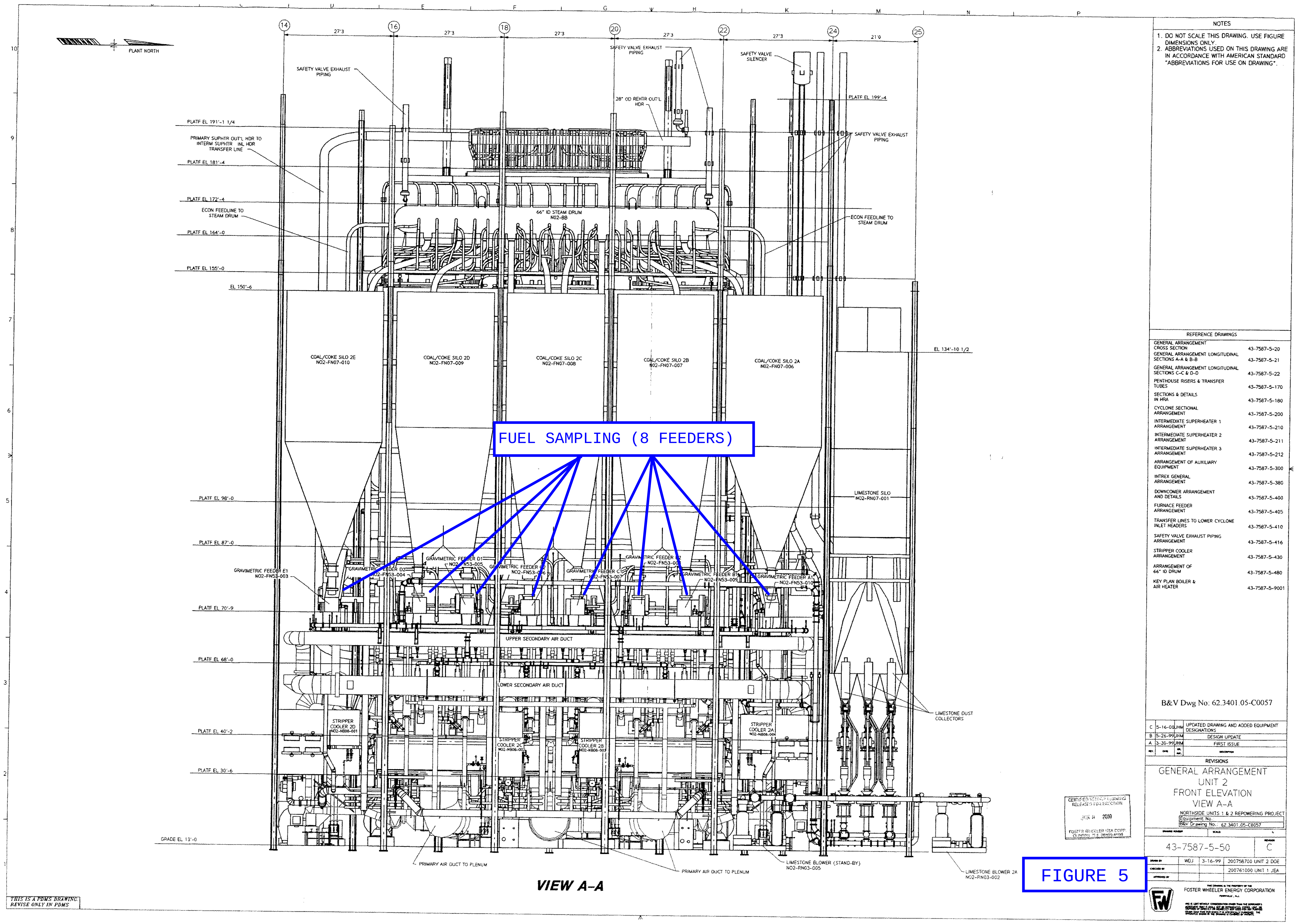
DRAWING NUMBER: 43-7587-5-53 — REVISION: C

DRAWN BY	JHM	3-16-99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

THIS IS A PDMS DRAWING. REVISE ONLY IN PDMS

FOSTER WHEELER ENERGY CORPORATION

DWG40998 03-MAR-2004 14:30:16



DWG40998 03-MAR-2004 14:18:59