PRELIMINARY FIELD EVALUATION OF MERCURY CONTROL USING COMBUSTION MODIFICATIONS

Annual Report

January 23, 2003 – January 22, 2004

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Abstract

In this project General Electric Energy and Environmental Research Corporation conducts a preliminary field evaluation of a novel technology, referred to as Hg/NO_x, that can reduce emissions of both mercury (Hg) and oxides of nitrogen (NO_x) from coal-fired power plants. The evaluation takes place in Green Station Unit 2 operated by Western Kentucky Energy. Reduction of Hg and NO_x emissions in Unit 2 is achieved using coal reburning.

Activities during first project year (January 23, 2003 – January 22, 2004) included measurements of baseline Hg emissions in Unit 2 and pilot-scale testing.

Baseline testing of Hg emissions in Green Unit 2 has been completed. Two fuels were tested with OFA system operating at minimum air flow. Mercury emissions were measured at ESP inlet and outlet, and at the stack using Ontario Hydro revised method. Testing demonstrated that baseline Hg reductions at ESP outlet and stack were 30-45% and 70-80%, respectively.

Pilot-scale testing demonstrated good agreement with baseline measurements in Unit 2. Testing showed that fuel composition had an effect on the efficiency of Hg absorption on fly ash. Maximum achieved Hg removal in reburning was close to 90%. Maximum achieved Hg reduction at air staging conditions was 60%. Testing also demonstrated that lowering ESP temperature improved efficiency of Hg removal.

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Executive Summary

In this project General Electric Energy and Environmental Research Corporation (EER) conducts a preliminary field evaluation of a novel technology, referred to as Hg/NO_x, that can reduce emissions of both mercury (Hg) and oxides of nitrogen (NO_x) from coal-fired power plants. The evaluation takes place in Green Station Unit 2 located near Henderson, Kentucky and operated by Western Kentucky Energy. Reduction of Hg and NO_x emissions in Unit 2 is achieved using coal reburning.

Reburning is a commercial two-stage fuel injection technology which reduces NO_x by staging the fuel injection into the furnace to produce a slightly fuel-rich environment above the existing burner zone, where NO_x concentrations can typically be reduced by 50-60%. Recent EER's experimental data demonstrated that fly ash formed "in-situ" in the reburning process could absorb Hg from flue gas as fly ash is collected in a Particulate Control Device.

The program comprises field and pilot-scale tests, engineering studies and consists of five tasks. Activities during first year of the project (January 23, 2003 – January 22, 2004) included measurements of baseline Hg emissions in Unit 2 and pilot-scale testing.

Baseline testing of Hg emissions in Green Unit 2 has been completed. Two fuels were tested with OFA system operating at minimum air flow. Mercury emissions were measured at ESP inlet and outlet, and at the stack using Ontario Hydro revised method. Testing demonstrated that baseline Hg reductions at ESP outlet and stack were 30-45% and 70-80%, respectively.

Pilot-scale testing was conducted in 300 kW Boiler Simulator Facility (BSF) to evaluate effects of process conditions and fuel type on Hg emissions. The same fuels fired in Unit 2 were evaluated in pilot-scale testing. Temperature gradient in BSF was adjusted to simulate thermal environment in Unit 2. High carbon fly ash was formed using two approaches: air staging and coal reburning. Process variables in tests included location of overfire air injection, amount of overfire air, amount of the reburning fuel, and ESP temperature. Concentrations of total Hg and elemental Hg (Hg^0) were measured at ESP outlet.

Pilot-scale testing demonstrated good agreement with baseline measurements in Unit 2. Testing showed that fuel composition had an effect on the efficiency of Hg absorption on fly ash. Maximum achieved Hg removal in reburning was close to 90%. Maximum achieved Hg reduction at air staging conditions was 60%. Testing also demonstrated that lowering ESP temperature improved efficiency of Hg removal.

1.0 Introduction

In this project General Electric Energy and Environmental Research Corporation (EER) conducts a preliminary field evaluation of a novel technology, referred to as Hg/NO_x, that can reduce emissions of both mercury (Hg) and oxides of nitrogen (NO_x) from coal-fired power plants. The evaluation takes place in Green Station Unit 2 located near Henderson, Kentucky. Green Station is owned and operated by Western Kentucky Energy (WKE). Reduction of Hg and NO_x emissions in Unit 2 is achieved using coal reburning.

The combined Hg/NO_x control method utilizes coal reburning (injection of reburning coal and overfire air) and an Electrostatic Precipitator (ESP) to capture the fly ash. In reburning technology, most of the coal (70-80%) is burned in the primary combustion zone of the boiler, where NO_x is typically generated. The remaining coal is injected downstream to provide a reburning zone with a fuel-rich environment where about 50-60% of the NO_x from the primary combustion zone is reduced to N_2. During the reburning process, carbon in the reburn coal will not burn out as completely as it would in a boiler environment with a high level of excess air. Thus, coal reburning increases the level of unburned carbon in the fly ash. This carbon is used to control Hg emissions. Most of the coal Hg content is transferred to the gas phase in the primary combustion zone of the boiler. Mercury in flue gas is absorbed by carbon present in the fly ash in the ESP. This fly ash can be landfilled or optionally treated in an ash burnout unit to recover heat. Carbon bed can be used to absorb Hg released from fly ash in the burnout unit. Mercury absorption in carbon bed can be done more economically than in the boiler. Since fly ash generated at Green Station is landfilled, Hg recovery in ash treatment system could not be investigated in this project.

The program comprises field and pilot-scale tests and engineering studies and consists of the following five tasks:

1. Baseline field measurements
2. Pilot-scale testing
3. Systems design
4. Preliminary field evaluation
5. Data reduction, management and reporting.

Task #1 provides baseline data on Hg emissions in Unit 2 before reburning system retrofit. Data collected in Task #1 will be also used to compare with pilot-scale data obtained in

Task #2 to evaluate scalability of pilot-scale data. Pilot-scale facility in Task #2 will be configured to match time-temperature profile found in Unit 2. The same fuels fired in full-scale will be tested in pilot-scale. Baseline data on Hg emissions and pilot-scale results will be evaluated in Task #3 to determine optimum conditions for Hg removal in Unit 2 when reburning system is operational. Armed with the pilot scale information, a field optimization program in Unit 2 will be structured in Task #4 to achieve the conditions identified in the pilot-scale using the advanced combustion systems. The goals of these tests are to identify stable conditions that yield high Hg capture, low NO_x emissions, low byproducts (CO, LOI) and are acceptable operating conditions for WKE operators.

Activities during first year of the project included measurements of baseline Hg emissions in Unit 2 and pilot-scale testing of fuels fired at Green Station.

The following sections describe in details activities during the first year of the project and plans for future work.

2.0 Characterization of Baseline Mercury Emissions in Unit 2

Goal of this task was to collect data on Hg emissions in Unit 2 before reburning retrofit. These data will be used to quantify reduction in emissions after reburning system retrofit and to evaluate scalability of pilot-scale data. Overfire (OFA) system was installed and tested in Unit 2 in February 2003. The OFA system can be operated in conjunction with reburning system (after Unit 2 is retrofitted with the reburning system) or separately. Mercury emissions in Unit 2 during baseline testing were measured with and without OFA system in operation.

Following sections give description of Unit 2 and activities during baseline testing.

2.1 Unit 2 Description

Western Kentucky Energy's Green Station Unit 2 is an opposed-wall-fired steam generator manufactured by Babcock and Wilcox. It was designed with a peak generating capacity of 250 MWe (gross). At its maximum continuous rating, the unit was originally designed to produce 1,840,000 lb/hr of main steam with superheater outlet conditions of 1,005 °F (814 K) at 1,975 psig. The unit also has a reheat steam capacity of 1,650,000 lb/hr at 1,005 °F (814 K) and 530 psig. The minimum control load is 120 MW. A side view schematic of the Green Unit 2 is shown in Figure 1. The furnace cross section has a depth of 13.5 m and a width of 12 m.

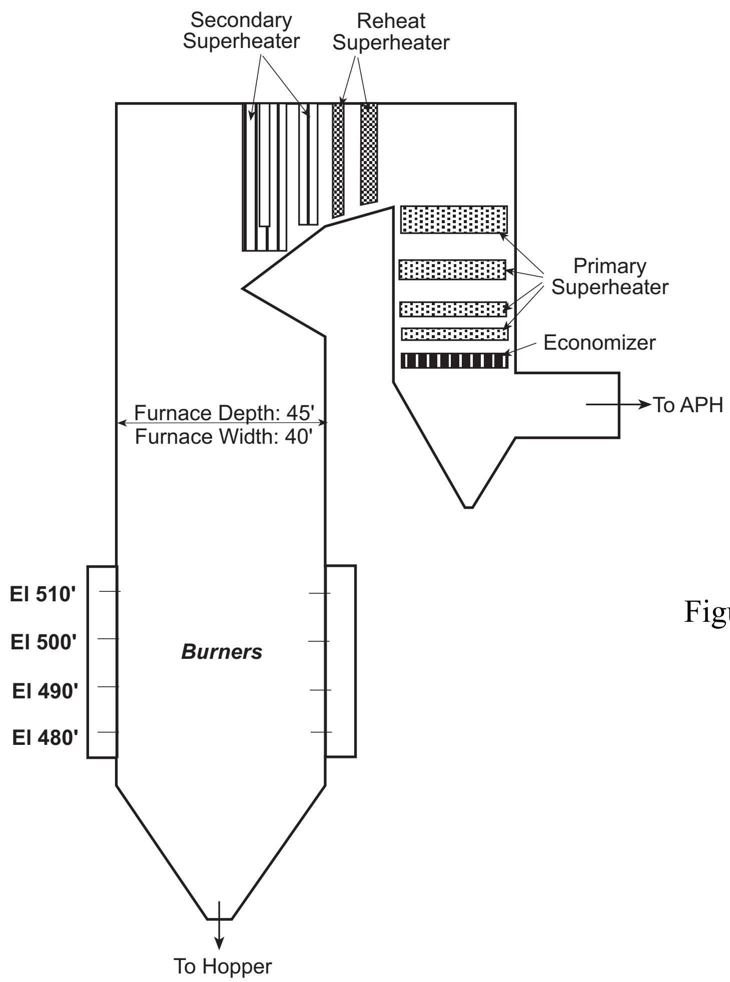

Figure 1. Side elevation of Green Unit 2.

The oxygen set point in Unit 2 is typically 3.0 to 3.5 percent at the economizer exit. As boiler load drops, boiler excess O_2 is increased to maintain reheat steam temperature. Loss-on-ignition (LOI) for the fly ash is reported to be less than 2 percent when firing bituminous coal. When the unit is fired with coal blends, however, LOI can be as high as 20 to 30 percent.

The overfire air system consists of 10 ports located at Elevation 165 m. Five ports are located on the front wall and five ports are located on the rear wall. Heated combustion air is supplied from the secondary air ducts on the hot side of the air heater. The overfire air ports are EER's double concentric design that contains an inner and outer nozzle. In most operating modes, the inner nozzle supplies between 12% and 15% of the total air. The remaining air is supplied through the outer nozzle. The air fraction to either nozzle can be controlled automatically from the control room.

2.2 Mercury Test Program

The test program consisted of 5 tests with the boiler operating under nominal full load conditions. Table 1 shows a matrix of the test program. The boiler was configured in the normal firing configuration, that is, with the upper row of burners in service and cooling air flowing through the overfire air injectors. The total cooling air accounted for 11-12% of the total combustion air. Thus, baseline tests corresponded to Unit 2 operating at slightly air staged conditions. Tests 1, 2, and 3 were conducted with the boiler firing the coal blend (see *Attachment I* Table I-1 for details on fuel composition). Tests 4 and 5 were conducted with the boiler firing 100% coal. For Test 5, OFA was increased to 22% to measure the impact of a moderate staging on Hg emissions.

Table 1. Mercury program test matrix.

		Fuel	OFA	Ontario Hydro Sampling			Other Sampling
Day	Test No			ESP Inlet	ESP Outlet	Stack	
30-Sep	1	Fuel #3	11%	X	X		Coal, hopper ash, and fly ash
1-Oct	2	Fuel #3	11%	X		X	Coal, hopper ash, and fly ash
1-Oct	3	Fuel #3	11%		X	X	Coal, hopper ash, and fly ash
2-Oct	4	Fuel #1	11%		X	X	Coal, hopper ash, and fly ash
2-Oct	5	Fuel #1	22%		X	X	Coal, hopper ash, and fly ash

Relative Hg measurement locations are shown in Figure 2. Manual Hg sampling using the Ontario Hydro Method was performed at three locations: the ESP inlet, the ESP outlet, and the stack. Fuel samples were collected from the silos, fly ash was collected from the economizer exit duct, and hopper ash was collected from the ESP hoppers during each test. EER also performed O_2 profiling at the ESP inlet because of the possibility of O_2 stratification as the flow makes a ninety-degree turn into the ESP. To closely monitor boiler operations, EER also measured O_2 on a dry basis continuously during each test at the economizer exit duct. All measurements were made on the boiler's East side duct.

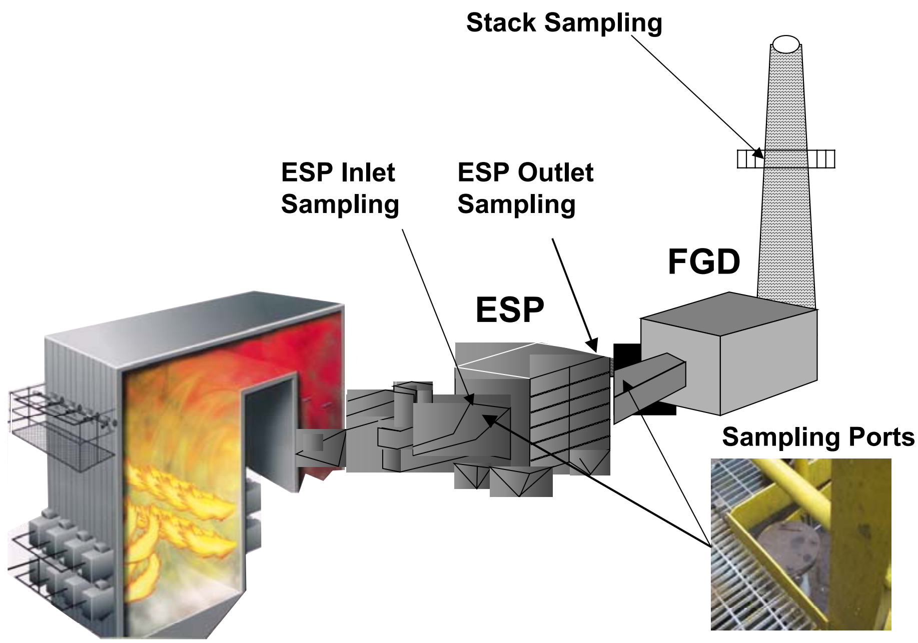

Figure 2. Sampling locations.

2.3 Data Collection and Sampling Procedures

Pertinent data from plant operations were collected to document the operating conditions of the boiler as part of the Hg test program. This section of the report summaries the sampling procedures that were used in the test program, and the data collection protocols that were followed. The following is a summary of the data collection activities.

- Boiler operating data from the plant information system
- NO_x, CO_2 and SO_2 from the plant CEMS at the stack
- Plant O_2 from plant sensors at the economizer outlet
- O_2 from 12 point sampling grid at the East economizer outlet
- O_2 stratification checks at the East ESP Inlet
- Hg concentrations by Ontario Hydro Method
- Coal samples
- Fly ash samples.

Following sections present summary of the boiler operating data, O_2 measurements, coal and fly ash sampling, and Hg emissions.

2.4 Boiler Operating Data

Boiler operating data were downloaded from the plant's digital information network at the end of each test day. The data points included measured steam, fuel, flue gas, and combustion air flows and properties, power output, CEMS data, and plant O_2 data. Each point was logged by the PI system at one-minute intervals and averaged across the exact sampling period for each test. A summary of the operating data is included in *Attachment I* Table I-2.

To characterize the operating conditions of the boiler, the data were used to calculate boiler efficiency and the actual fuel and air flows. Boiler efficiency was calculated using the ASME PTC 4.1 Heat Loss Efficiency Method. For these calculations, fuel analysis was provided from the actual samples taken during the tests (Table I-1), and the carbon loss was measured from the actual fly ash samples collected during the tests. A heat balance was then used to calculate the actual fuel flow and the plant O_2 measurements were used to calculate the actual airflow. Stoichiometric values for the burner zone and for the OFA zone as well as the percent OFA are included in the *Attachment I* Table I-2.

2.5 Continuous O_2 Monitoring /O_2 Profiling

A 12-point sampling grid was installed in the East duct of the economizer exit duct to monitor O_2 concentrations during the tests. Sintered metal filters were installed on the end of each probe to remove ash particles from the flue gas. The gas extracted from each point was metered to ensure uniform sampling. A moisture knockout device was used to remove moisture from the flue gas sample. The dry flue gas sample was then pumped to the mobile CEMS laboratory for analysis of O_2 concentration. The analyzer was calibrated using an EPA Protocol 1 calibration gas before and after each test. A bias check was performed prior to test number 1 to insure the integrity of the sampling line and leak checks were conducted on a daily basis.

Figure 3 shows oxygen profile across East side duct. Oxygen traversing was done on four occasions: prior to the beginning of the test program and on each of test days. Traversing was done across distance of 180 cm which comprises half the duct length. Figure 3 demonstrates that relatively small O_2 bias (about 10%) exists across the flow indicating that flow is well mixed. This suggests that Hg bias at the location of Hg measurements at ESP inlet is also small. Due to the intense flue gas mixing in ESP and wet scrubber, it is expected that Hg bias at the location of

Hg measurements at ESP outlet and stack to be even smaller. A velocity traverses made at these three locations during Ontario Hydro sampling confirmed the flow uniformity (see Section 2.8).

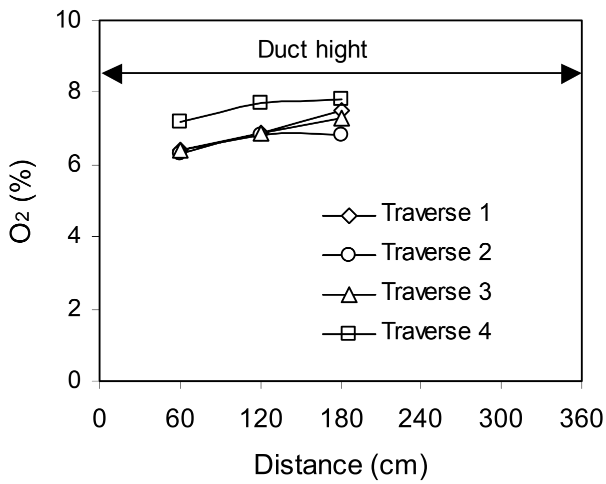

Figure 3. Oxygen profile across East side duct.

2.6 Coal Sampling

Coal samples were taken during the second half of each test period. To achieve the most representative sample, coal was acquired from the bottom of the four coal silos. A composite sample was then assembled by combining an equal mass from each of the individual silo samples. The samples were labeled to include the test number, sampling time, and sampling location and sent to an independent laboratory for determinations of ultimate, proximate, and heating value as well as Hg concentration. Table I-1 in *Attachment I* shows composition of tested fuels.

2.7 Fly Ash Samples

Fly ash samples were collected in-situ from the East side economizer exit duct. The fly ash sampling system consisted of a multi hole probe that ran the width of the economizer exit duct, a high volume sampler that was used to pull flue gas, and a cyclone to capture the ash into a plastic jar. At the completion of each test, the samples were placed in an airtight container, labeled, and shipped to a laboratory for analysis. The ash samples were analyzed for LOI using a Hot Foil™ LOI Analyzer. The LOI data for tests 1-5 are shown in *Attachment I* Table I-2.

2.8 Mercury Emissions

Mercury emissions were measured using the Ontario Hydro Method, Revised July 7, 1999. Two tests were conducted at ESP inlet, four at ESP outlet, and four at the stack. A preliminary velocity traverses were made at each location in order to determine the uniformity and magnitude of the flow prior to testing. Several traverse point at each location were checked for cyclon flow and none was found to be present. Three traverse points were sampled at each of ESP locations and twelve points were sampled at the stack. For each run at ESP inlet and outlet samples of flue gas of 55 min duration were taken isokinetically at each of the traverse points for a total sampling time of 150 min. At the stack samples of 10 min duration were taken isokinetically at each of the twelve traverse points for a total sampling time of 120 min. Tables 2-1 – 2-3 show results of Ontario Hydro measurements.

Table 2-1. Summary of results for ESP inlet duct.

Test Number	1	2
Duct Flow Rate (acfm)	357,272	384,070
%O_2 (%Vol)	4.6	4.4
Duct Temperature (F)	310	313
Particle Bound Mercury Emissions ($\mu g/m^3$)	0.19	0.079
Elemental Mercury Emissions ($\mu g/m^3$)	0.607	0.735
Oxidized Mercury Emissions ($\mu g/m^3$)	7.122	7.127
Total Mercury Emissions ($\mu g/m^3$)	7.919	7.941

Table 2-2. Summary of results for ESP outlet duct.

Test Number	1	3	4	5
Duct Flow Rate (acfm)	260,175	271,313	264,213	280,834
%O_2 (%Vol)	4.6	4.6	4.6	4.2
Duct Temperature (F)	316	316	294	299
Particle Bound Mercury Emissions ($\mu g/m^3$)	0.016	0.009	0.005	0.004
Elemental Mercury Emissions ($\mu g/m^3$)	1.145	1.131	2.26	1.958
Oxidized Mercury Emissions ($\mu g/m^3$)	4.909	3.658	9.109	7.527
Total Mercury Emissions ($\mu g/m^3$)	6.070	4.798	11.374	9.489

Figures 4 and 5 show Hg emissions for fuels #1 and #3 at different locations. Typical of bituminous coals, most Hg in the gas phase at ESP inlet and outlet is present in the oxidized form. Total mercury at the stack is significantly lower than that before wet scrubber and present mostly in the elemental form.

Table 2-3. Summary of results for the stack.

Test Number	2	3	4	5
Duct Flow Rate (acfm)	783,470	799,894	816,248	827,442
$\%O_2$ (%Vol)	4.2	4.2	4.6	4.4
Duct Temperature (F)	121	123	121	127
Particle Bound Mercury Emissions ($\mu g/m^3$)	0.026	0.077	0.016	0.081
Elemental Mercury Emissions ($\mu g/m^3$)	1.489	1.278	2.433	2.165
Oxidized Mercury Emissions ($\mu g/m^3$)	0.662	0.481	1.142	0.806
Total Mercury Emissions ($\mu g/m^3$)	2.177	1.836	3.591	3.052

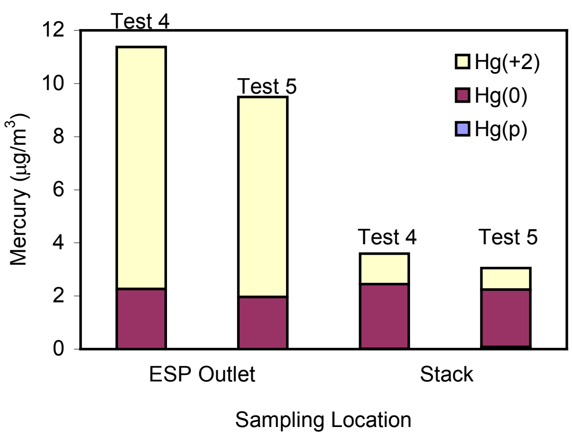

Figure 4. Mercury emissions for fuel #1.

Figures 6 and 7 show efficiencies (defined as a difference between theoretical Hg concentration in the gas phase calculated using coal feed rate and coal Hg content and that measured) of Hg removal for fuels #1 and #3. Testing showed (Figure 7) that Hg removal at ESP inlet was small. Mercury concentration at ESP inlet agreed with the theoretical value within ±15%. This suggests that practically all Hg present in coal is released into flue gas during combustion process and very little Hg if any is absorbed on bottom fly ash. Mercury removal at ESP outlet for fuels #1 and #3 was 30-45% and 70-80% at the stack. These data agree well with average Hg removal efficiencies of 46% and 81% reported by utilities for bituminous coal for similar configurations in respond to EPA Information Collection Request (L. Lindau, M.

Durham, J. Bustard, C. Martin "Mercury: myths and realities", Modern Power Systems, March 2003, p. 30).

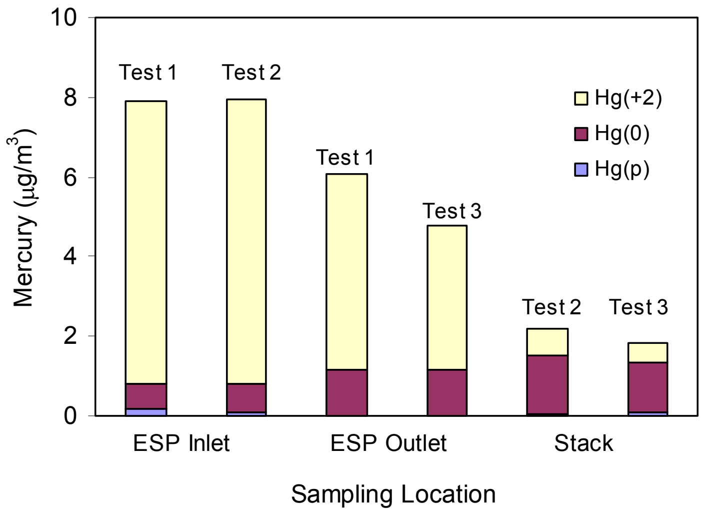

Figure 5. Mercury emissions for fuel #3.

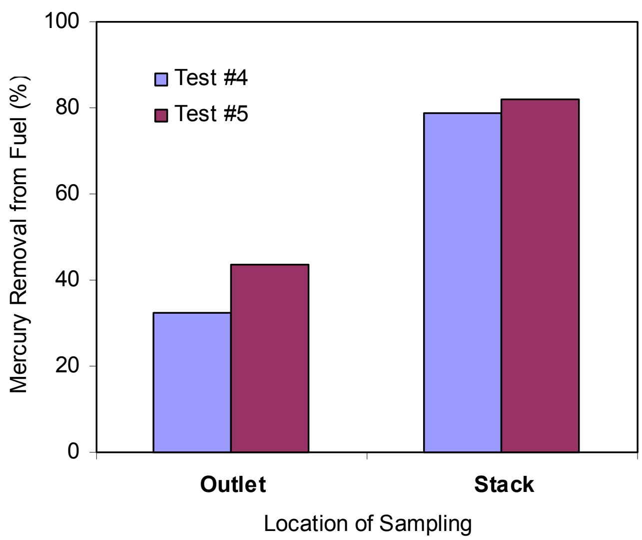

Figure 6. Mercury removal efficiencies for fuel #1.

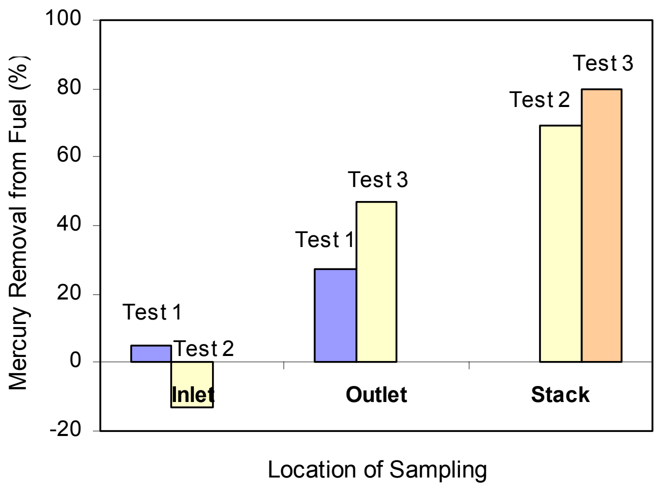

Figure 7. Mercury removal efficiencies for fuel #3.

Efficiency of Hg removal across FGD (defined as a difference between Hg concentration at ESP outlet and stack) was in the range of 65-70%. Reduction in concentration of the oxidized Hg was about 90%. However, about 20% of the oxidized Hg was reduced to elemental across the scrubber. As a result, elemental Hg at the stack was about 70% of total Hg emissions.

3.0 Pilot-Scale Testing

Pilot-scale testing was conducted in Boiler Simulator Facility (BSF) to determine effects of process conditions and fuel composition on Hg removal. The following sections give BSF description and present results of pilot-scale testing.

3.1 Boiler Simulator Facility

The BSF (Figure 8) is a down-fired combustion research facility with a nominal firing rate of 300 kW. It is designed to simulate the thermal characteristics of a utility boiler. As shown in Figure 8, the BSF consists of a burner, vertical radiant furnace, and horizontal convective pass. The facility's variable swirl diffusion burner is equipped to fire coal, oil, or natural gas. The furnace is constructed of eight modular refractory lined spool sections with access ports. The furnace has an inside diameter of 0.55 m and a height of 5.4 m. The radiant section is equipped with adjustable heat removal panels. Configuration of these panels is adjusted such that the BSF matches the residence time-temperature profile and furnace exit gas temperature of a specific full-scale boiler. The convective pass is equipped with air-cooled tube bundles designed to simulate the superheater and economizer sections of a coal-fired boiler.

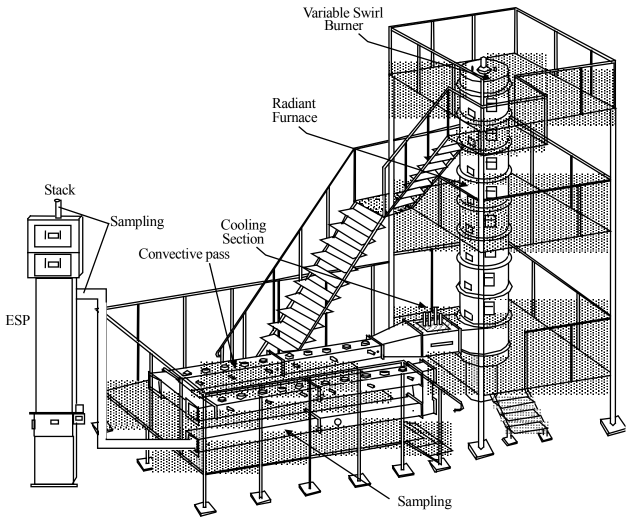

Figure 8. Boiler Simulator Facility (BSF).

Temperature gradient in BSF was adjusted to simulate thermal environment in Unit 2. Figure 9 compares axial temperature profile in the BSF and Unit 2. Unit 2 temperature profile was calculated using EER's thermal model that was successfully used in the past to predict temperature environment in coal-fired boilers. Figure 9 shows good agreement between full- and pilot-scale temperature profiles at temperatures below 1200 K at which Hg oxidation and adsorption on fly ash is expected to take place.

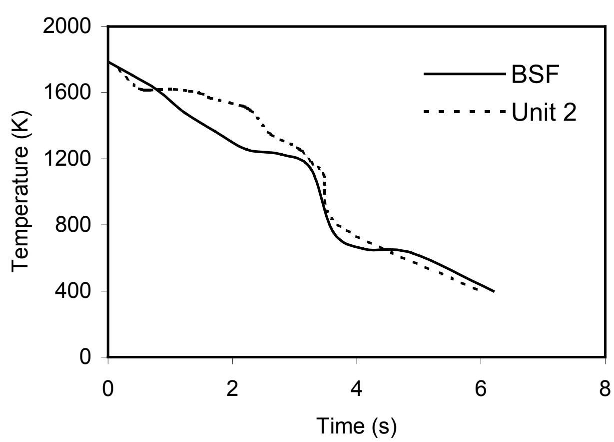

Figure 9. Axial temperature profiles in BSF and Unit 2.

The ESP for the BSF is a single-field down-fired cylindrical unit with an axial corona electrode.

Process performance was characterized by continuous emissions monitors (CEMs), which provided an online analysis of flue gas composition. The CEMs consisted of a water-cooled sample probe, sample conditioning system (to remove water and particulate), and gas analyzers. Species analyzed, detection principles, and detection limits were as follows:

- O_2: paramagnetism, 0.1%
- NO_x: chemiluminescence, 1 ppm
- CO: nondispersive infrared, 1 ppm
- CO_2: nondispersive infrared, 0.1%

High purity dry nitrogen was used to zero the analyzers. Certified span gases were used to calibrate and check linearity of the analyzers. A chart recorder was used to obtain a hard copy of analyzer outputs. A personal computer based data acquisition system (LabTech Notebook) was used for storage and analysis of test data. Mercury measurements were conducted using a CEM Sir Galahad from PS Analytical.

3.2 Results of Pilot-Scale Testing

Combustion tests were performed to evaluate effects of process conditions and fuel type on Hg emissions. Characteristics of tested fuels are shown in *Attachment I* Table I-3. Concentrations of total Hg and elemental Hg (Hg^0) were measured at ESP outlet. Concentration of oxidized Hg (Hg^{+2}) was determined as a difference between Hg and Hg^0.

High carbon fly ash was formed using two approaches: air staging and coal reburning. In air staging, part of the combustion air (usually 15-30% of total) is redirected from the main combustion zone into overfire (OFA) zone. In reburning, part of the fuel (usually 10-30% of total) is injected downstream of the main combustion zone (reburning zone); overfire air is injected downstream of the reburning zone to complete fuel combustion. In both approaches fuel combustion occurs in more fuel-rich environment than at typical combustion conditions resulting in incomplete fuel combustion and increased carbon in ash content (characterized as Loss on Ignition, or LOI). However, in reburning combustion of secondary (reburning) fuel takes place at lower temperatures than in air staging which potentially can affect properties of fly ash and its reactivity towards Hg.

Process variables in tests included location of OFA injection, amount of OFA, amount of reburning fuel, and ESP temperature. The ESP temperature was adjusted by changing facility load.

Figure 10 shows Hg removal for three tested fuels as a function of LOI at air staging conditions. Figure 10 demonstrates that at air staging conditions efficiency of Hg removal increases as LOI increases from 0% up to 5-6%, but then stays about that same as LOI increases to 16%. Mercury removal efficiencies for all three tested fuels were similar at the same LOI. It should be noted, however, that because of different reactivity of fuels the same combustion conditions generated fly ash with different LOI. Thus, although data presented in Figure 10 can be used to establish target LOI required to achieve desired Hg removal efficiency, combustion conditions that produce target LOI are affected by coal composition. Maximum achieved Hg reduction in air staging tests was 60%. The ESP temperature in air staging tests was 350 ^oF (450 K).

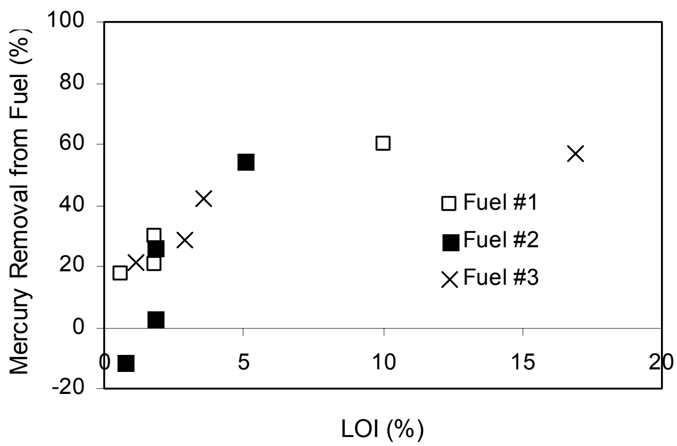

Figure 10. Mercury removal as a function of LOI at air staging.

Effects of reburning and ESP temperature on Hg removal were evaluated for fuels #1 and #3. Figure 11 shows Hg removal efficiency as a function of LOI at ESP temperatures in the range of 310-360 ^oF (427-455 K).

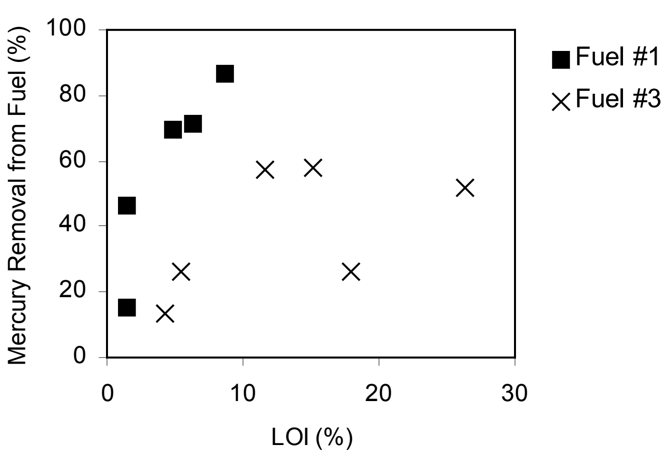

Figure 11. Mercury removal as a function of LOI at reburning conditions at ESP temperatures of 310-360 ^oF.

Figure 11 demonstrates that Hg removal efficiencies for fuel #1 are higher than that for fuel #3 at the same LOI. Maximum LOI generated in reburning tests for fuel #3 was ~26% while for fuel #1 it was ~9%. This is result of higher reactivity of fuel #1 due to its higher volatiles content (Table I-3). Maximum achieved Hg removal efficiency for fuel #1 was close to 90% while for fuel #3 it was 60%. It suggests that in reburning fuel properties have a significant effect on fly ash reactivity towards Hg.

Figure 12 shows efficiency of Hg removal for fuel #1 at reburning conditions at different ESP temperatures. For comparison, data on the effect of LOI and ESP temperature on Hg removal obtained by Consol (Final technical Report to ICCI, Project 98-1/1.2B-2, W. A. Rosenhoover, CONSOL Inc.) are also shown. In that project fly ashes obtained from Illinois utility and industrial boilers were injected into 1.5 MM Btu/hr combustor duct and collected in ESP. Mercury removals were measured across the duct and ESP. The flue gas temperature was controlled using both humidification with an in-duct atomization nozzle and the pilot plant heat exchanger. CONSOL data showed that Hg absorption on fly ash was affected by LOI and improved as ESP temperature decreased.

Figure 12 demonstrates that ESP temperature has an effect on Hg removal: Hg removal at 250-270 ^{o}F (394-405 K) at LOI ~5% was ~80% while at 440-450 ^{o}F (500-505 K) it was only ~15%. This suggests that lowering ESP temperature can be an effective approach to increase Hg adsorption on fly ash.

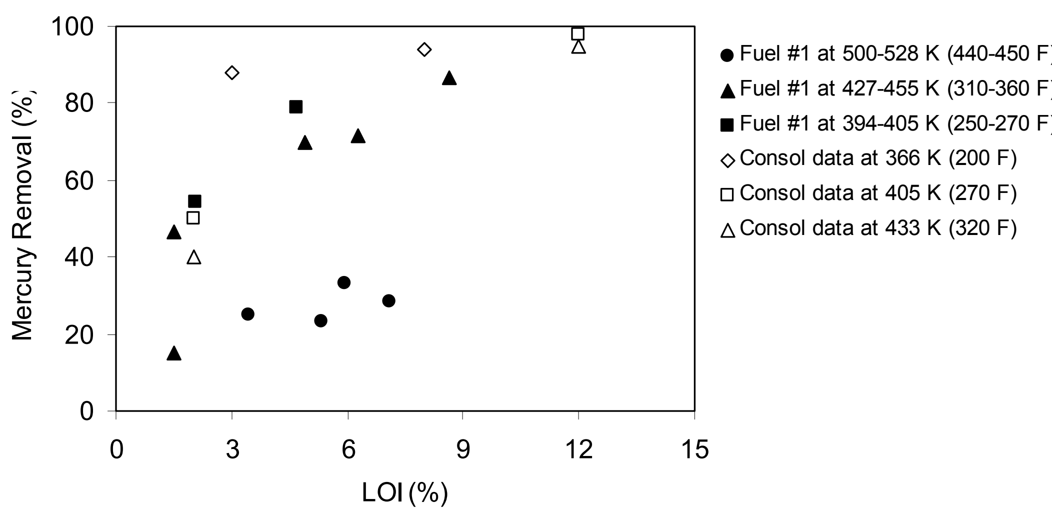

Figure 12. Mercury removal for fuel #1 at reburning conditions at different ESP temperatures as a function of LOI. Data obtained by Consol on re-injection of high carbon fly ash are also shown.

Data on effects of LOI and ESP temperatures were used to develop empirical correlation between Hg removal, LOI, and ESP temperature. Figure 13 shows comparison between experimental data and correlation predictions. Figure 13 demonstrates good agreement between calculated and experimental data for wide ranges of LOIs and temperatures.

Figure 14 shows experimental data on Hg removal obtained in BSF (presented in Figure 12) at ESP temperatures of 250–450 ^{o}F (390 – 500 K) and adjusted using empirical correlation to the temperature of 350 ^{o}F (450 K). Figure 14 shows good agreement between experimental data and correlation predictions. It also shows that uncertainty of experimental data is about ±10%.

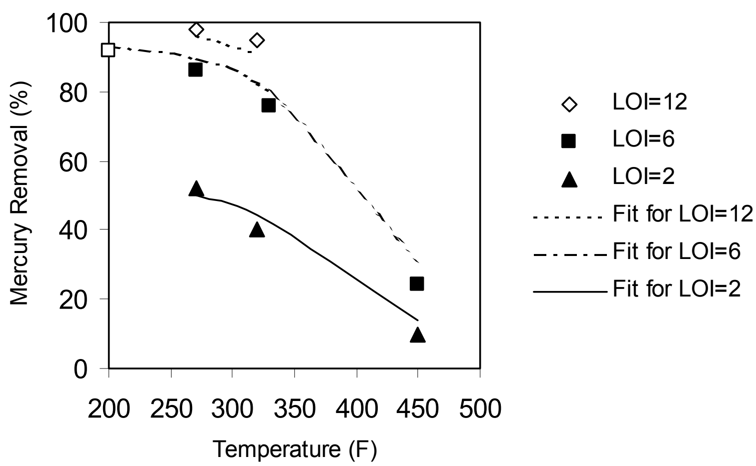

Figure 13. Effect of ESP temperature on Hg removal. Filled symbols represent present data, open symbols Consol data, lines correlation predictions.

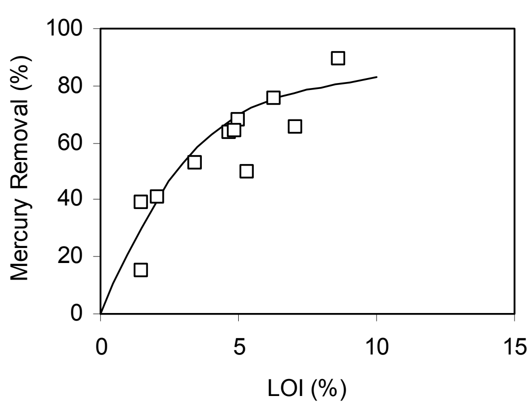

Figure 14. Mercury removal in reburning as a function of LOI. ESP temperature is 350 ^{o}F (450 K).

4.0 Comparison Of Full- and Pilot-Scale Data

Figures 15 and 16 show comparison of Hg removal efficiencies measured at ESP outlet in full- and pilot-scale for fuels #1 and #3. Figures 15 and 16 show that full-scale data are in agreement with pilot-scale measurements for both fuels suggesting that BSF adequately simulates thermal environment of Green Unit 2. Figure 15 also demonstrates that significant improvement in Hg removal can be achieved for fuel #1 by increasing LOI to 6-10%. Comparison (Figure 16) of baseline and pilot-scale measurements for fuel #3 suggests that LOI increase above 8-9% achieved in baseline measurements will not result in a significant Hg removal improvement. It demonstrates that fuel properties play a significant role in defining efficiency of Hg absorption on fly ash.

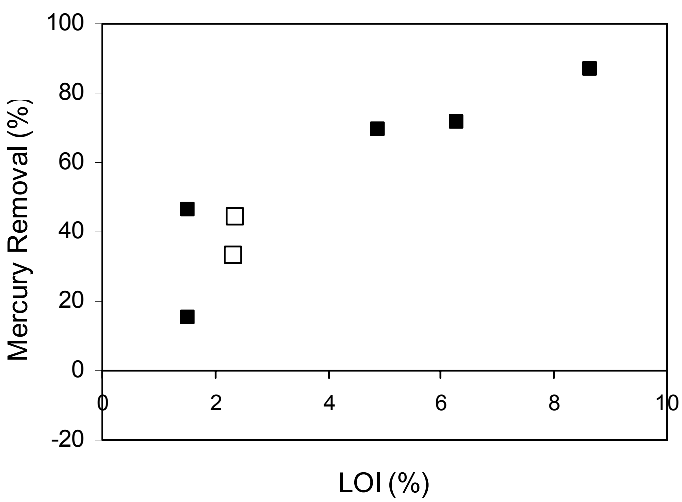

Figure 15. Comparison of pilot- (filled symbols) and full-scale (open symbols) data for OFA tests for fuel #1.

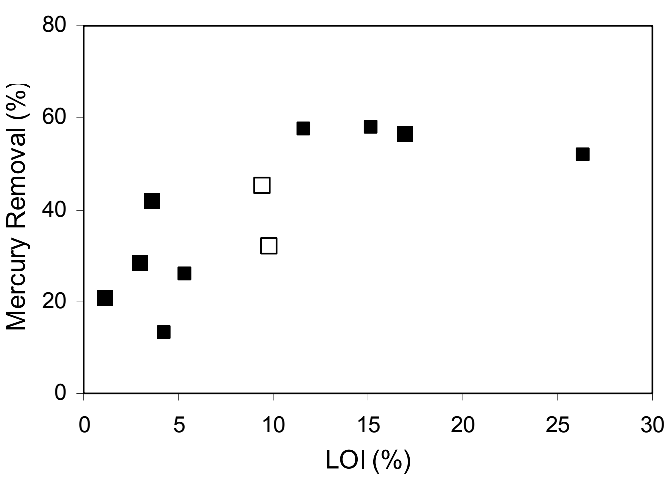

Figure 16. Comparison of pilot- (filled symbols) and full-scale (open symbols) data for OFA tests for fuel #3.

Figures 17 and 18 show good agreement on Hg partition measured in full- and pilot-scale testing. Data demonstrate that at ESP outlet oxidized Hg comprises about 80% of total Hg.

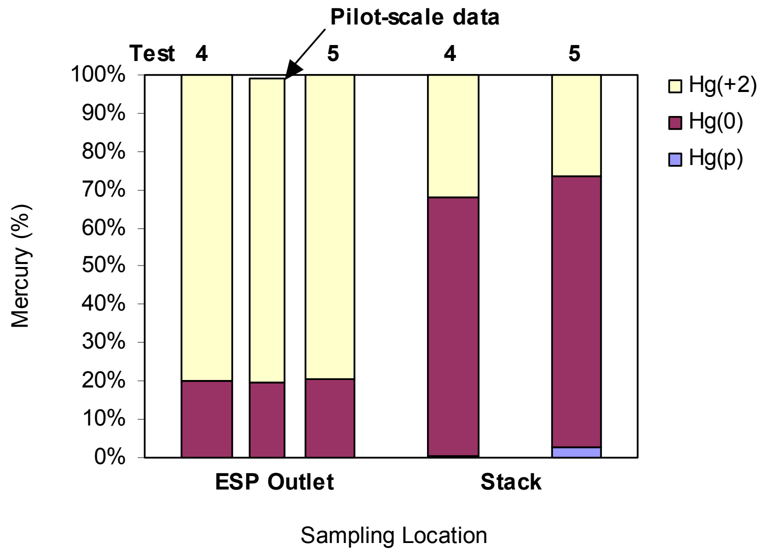

Figure 17. Mercury partition in full- and pilot-scale tests for fuel #1.

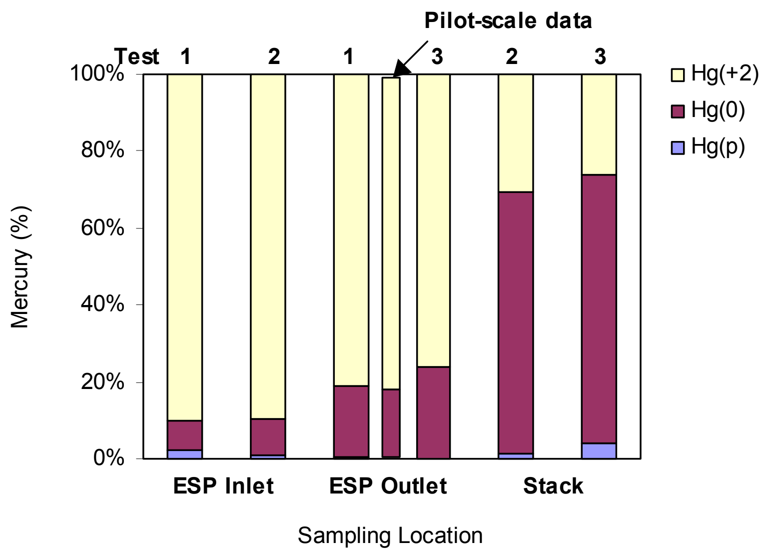

Figure 18 Mercury partition in full- and pilot-scale tests for fuel #3.

5.0 Summary

Baseline testing of Hg emissions in Green Unit 2 has been completed. Two fuels were tested with OFA system operating at minimum air flow. Mercury emissions were measured at 11% overfire air at ESP inlet and outlet, and at the stack using Ontario Hydro revised method. Testing demonstrated that Hg reductions at ESP outlet and stack were 30-45% and 70-80%, respectively. Testing also demonstrated that OFA system operation at 22% air resulted in 10% and 5% incremental increase in Hg removal efficiencies at ESP outlet and stack, respectively. However, more tests are needed to verify statistical significance of these increases.

Pilot-scale testing demonstrated good agreement with baseline measurements in Unit 2. Testing showed that fuel composition had an effect on the efficiency of Hg absorption on fly ash. Maximum achieved Hg removal in reburning was close to 90%. Maximum achieved Hg reduction at air staging conditions was 60%. Testing also demonstrated that lowering ESP temperature improved efficiency of Hg removal.

Comparison of baseline and pilot-scale measurements suggests that increasing LOI for fuel #1 will significantly improve Hg removal efficiency in Unit 2 at ESP outlet and LOI increase for fuel #3 will not result in a significant improvement in Hg removal efficiency.

Baseline and pilot-scale testing results were used to develop test matrix for the second round of testing in Unit 2 (Table 3). Testing will focus on optimization of the reburning system while firing fuel #3.

Table 3. Draft test matrix for second round of testing in Unit 2.

	Fuel	Load (MW)	Reburn Fuel	Reburn Fuel (%)	OH Sampling		
Test No	Coal				ESP Inlet	ESP Outlet	Stack
1	Blend Fuel #3	242	Blend Fuel #3	30%	X	X	
2	Blend Fuel #3	242	Blend Fuel #3	30%		X	X
3	Coal	242	Coal	30%	X	X	
4	Coal	242	Coal	30%		X	X
5	Coal	242	Coal	30%		X	X
6	Coal	242	Coal	30%		X	X
7	Coal	181	Coal	30%	X	X	
8	Coal	178	Coal	30%		X	X

6.0 Future Work

Testing of Hg emissions in Unit 2 under reburning conditions was completed in January 2004. Goals of these tests were to demonstrate (1) significant reduction in NO_x and Hg emissions under optimized reburning conditions and (2) improved Hg capture on fly ash at reduced ESP temperatures. Mercury emissions were measured at the ESP inlet and outlet, and at the stack using the Revised Ontario Hydro method. Testing demonstrated that optimization of the reburning system for Hg control also resulted in reduction in NO_x emissions. The test data are being analyzed, but initial indications show that NO_x emissions were reduced below 0.15 lb/MBtu. The data on Hg emissions are expected from an independent laboratory by the end of February 2004. After Hg emission data become available, they will be analyzed to determine if testing objectives were achieved and additional pilot-and full-scale testing are needed.