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Modification of boiler operating conditions for mercury emissions reductions in coal-fired utility boilers

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Abstract

US EPA's studies have determined that mercury emissions from coal-fired power plants pose significant hazards to public health and must be reduced. Coal-fired power plants represent a significant fraction of the anthropogenic emissions of mercury into the atmosphere. Mercury emissions are impacted by factors such as coal type, boiler operation, fly ash characteristics and type of environmental control equipment installed on the unit. Field data show a wide variation in the fraction of mercury that is emitted in the gaseous phase, as elemental and oxidized mercury vapor, and as particulate-bound mercury. Oxidized mercury is a preferable species because is less volatile at stack temperatures, water-soluble, and tends to interact with mineral matter and char, and cold-end air pollution control devices. There is also evidence that boiler-operating conditions could be used to influence mercury behavior in the boiler, since they affect the thermo-chemical conditions for mercury formation and reduction. However, operation of boiler control settings, which result in mercury removal benefits, should also consider the tradeoff between mercury reduction and other emissions (for example, NO_x and CO), the level of unburned carbon in the fly ash, unit efficiency and the performance of particulate control equipment.

This paper reports fieldwork performed to investigate the feasibility of affecting mercury emissions from coal-fired plants by manipulating boiler control settings. Full-scale testing was performed at two units. One of the units is equipped with a back-end train that includes a rotary air preheater followed by two electrostatic precipitators in series. The other unit is equipped with hot and cold precipitators and a tubular air preheater. A strategy for mercury control by selectively manipulating boiler control settings, if used in combination with other control measures such as sorbent injection, should provide a cost-effective option for mercury control.

Keywords: Mercury emissions; Boiler optimization

1. Introduction

Of the 189 substances designated hazardous air pollutants by the US Environmental Protection Agency (EPA), mercury (Hg) has attracted significant attention due to its increased levels in the environment and well-documented food chain transport and bio-accumulation. Under the requirements of the 1990 Clean Air Act Amendments (CAAA), the US Environmental Protection Agency (EPA) has developed two major reports on Hg to the US congress: the Hg Study Report to Congress [1] and the Utility Hazardous Air Pollutant Report to Congress [2]. These reports concluded that during the period from 1994 to 1995, annual anthropogenic emissions of Hg in the United States were 158 ton, 87% of which were contributed by combustion sources, with coal-fired power plants constituting the largest source of Hg emissions in the country, with an annual average of 52 ton during 1994–1995. As a consequence, on December 15, 2003 EPA proposed a rule to permanently cap and reduce Hg emissions from coal-fired power plants.

EPA is proposing two alternatives that include requiring utilities to install controls known as maximum achievable control technologies (MACT) or establishing standards of performance that limit Hg emissions from new and existing utilities. MACT would reduce nationwide emissions of Hg by 29% by the end of 2007. If a Cap-and-Trade program is elected, a first phase using SO_2 and NO_x co-benefit controls will be due by 2010. Full implementation would take place by 2018, with 69% Hg emission reduction forecasted. In a parallel track, Clean Air Task Forces in some states are working on regulations that could establish stringent Hg emission standards for the states' coal-fired power plants. One example is the State of Connecticut, where legislation was introduced to achieve an Hg emission

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standard of 0.26 g/tJ or approximately 90% removal efficiency, effective in July 2008. The State of Massachusetts is taking a similar approach, with possible total Hg control in the 85–95% range from baseline boiler Hg outlet levels. This applies to the total Hg that exits the stack as the sum of elemental and oxidized gaseous Hg. As a result of these pending Hg regulations, research and development of mercury control techniques for control of Hg emissions from coal-fired has boilers become an urgent issue for the US power generation industry.

At combustion temperatures, Hg is present as elemental vapor (Hg^0). However, due to processes, which occur naturally in the boiler, by the time the flue gas reaches the back-end of the boiler, the Hg is present not only as Hg^0, but also as various oxidized forms (Hg^{2+}) and as particulate bound mercury (Hg_p). The breakdown between these different forms of Hg is highly variable in coal-fired flue gas. Data from full-scale studies [3, 4], including the Information Collection Request (ICR) data [5] show that the percentage emitted from different plants varied widely, from approximately 10 to 90% of Hg in the coal. The fate of Hg at the back-end of a coal-fired boiler is very important because it determines its stack emission and degree of control. Elemental mercury is insoluble and extremely volatile at the operating temperatures of typical air pollution control devices (APCD) and, hence, is much more difficult to capture. Since oxidized mercury is water-soluble, less volatile at stack temperatures and active with mineral matters, chars, and cold-end air pollution control devices, it can be removed in scrubbers, electrostatic precipitators (ESP) and fabric filters.

It is believed that the reasons for the variability in Hg emissions in coal-fired boilers are related to the interaction between the Hg chemistry, and the physical configuration and operation of a particular unit. Mercury emissions are particularly impacted by the coal type and composition, boiler design and type of environmental control equipment used at the plant, boiler operating conditions, and fly ash characteristics. Data indicate that chlorine (Cl) concentration is the single most important variable with respect to influencing mercury speciation and removal in coal-fired boilers [6]. However, boiler operation plays an important role on the concentration of Cl at the boiler back-end and, furthermore, on the overall fate of Hg. For example, an increase in the concentration of hydrogen chlorine (HCl) and carbon monoxide (CO) concentration would promote the pool of Cl atoms in the flue gas [7]. HCl and CO are directly related to the combustion conditions in the boiler, via flue gas residence time and temperature, and excess air. The effect of nitric oxide (NO) on Hg oxidation has been found to either promote or inhibit homogeneous Hg oxidation, depending on its concentration and flue gas quenching rates [8]. Nitrogen dioxide (NO_2) has been shown to oxidize (approximately 10% oxidation) elemental Hg in the temperature range of 250–370 °C [9]. The link between NO and NO_2, or NO_x, and boiler operating parameters is well documented and has been used to reduce NO_x emissions. This includes, for example, the impact of excess air and waterwall slagging in the boiler and their impact on flame temperature and in-flame O_2 availability. The presence of sulfur dioxide (SO_2) reduces the amount of elemental Hg oxidized by chlorine-based species [7]. However, the impact of boiler operating parameters on SO_2 is negligible.

Coal-fired boiler operational parameters also have a direct impact on Hg oxidation and the heterogeneous interactions between Hg and fly ash, because they can affect flue gas temperature, residence time, and the level of unburned carbon (UBC) in the ash. For example, the thermal performance of the boiler air preheater (APH), excess air level, and heat transfer surface cleanliness will impact homogeneous and heterogeneous Hg^0 oxidation due to the sensitivity of mercury oxidation to progressively faster quenching [8]. Heterogeneous interactions between Hg and fly ash is also impacted by boiler control settings. It has been indicated that the UBC in the ash is chlorinated by HCl and that heterogeneous oxidation of Hg into HgCl occurs on the chlorinated carbon sites [10]. The extent of this heterogeneous oxidation is reported to be proportional to the surface area of UBC in the ash, which is directly affected by the grinding performance of the coal pulverizers.

This paper reports on the results of full-scale field tests performed to investigate the impact of boiler operation on Hg emissions as a potentially cost-effective control technology. Enhancing the ‘naturally-occurring’ Hg capture in coal-fired boilers by modification to boiler control settings should contribute to reduce the cost of Hg emissions compliance. It is anticipated that there should be an economic benefit from this approach by reducing the amount and cost of post-combustion elemental mercury remediation that needs to be done to meet federal and state regulations. One of the mercury control methods that is receiving significant attention is adsorption of mercury by activated carbon. Injection of activated carbon upstream of either an electrostatic precipitator or a baghouse is the retrofit technology that has the widest potential application for controlling mercury emissions in plants that are not equipped with flue gas desulfurization (FGD) scrubbers (approximately 75% of all US plants). However, the use of activated carbon will result in a significant increase in the cost of electricity for coal-fired power plants. Mercury sorption capacities between 200 and 5000 μg Hg/g C have been reported for conditions applying to coal combustion [11]. However, in practice, carbon injection rates in the range of 10,000:1 are needed. Activated carbon typically costs $1.00 per kg, which represents a cost factor of about 0.4 mil/kW h at a C/Hg injection ratio of 10,000:1 for coal containing 0.1 ppm_w mercury. It has been estimated that it would cost approximately $30,000–$85,000 (1995 dollars) to remove each kilogram of mercury from flue gas using activated carbon. For a 250 MW unit emitting 65 kg of Hg per year, it is estimated that it would cost between $1 and 3 million to remove 50% of the mercury present. A strategy developed based on optimizing boiler operation for mercury control that results in a 25% increase in Hg oxidation/capture through boiler optimization will impact the cost calculation for the 250 MW plant by at least a million dollars annually.

2. Unit description and analytical equipment

Field tests at two units were performed to investigate the full-scale impact of boiler operations on Hg emissions.

These two units have different boiler designs, generating loads, and pollution control devices.

Unit A is a 250 MW pulverized coal-fired steam generator with a tangentially-fired boiler burning Eastern US bituminous coal, with an average Hg coal concentration of 0.06 ppm_w. This unit fires approximately 90 ton of coal per hour at full load using four coal pulverizers. Each pulverizer feeds one burner elevation, which consists of eight burners. Unit A is equipped with a low-NO_x combustion system consisting of offset concentric secondary air registers, close-coupled overfire air (CCOFA) and three elevations of separated overfire air (SOFA). The APH on this unit is of the rotating Ljungstrom type. The particulate control equipment on this unit consists of two cold-side ESP's in series. The nominal precipitator inlet gas temperature is 140 °C at full load. Hg sampling at this unit was conducted at four locations along one side of the convective pass duct. These locations correspond to points at the APH inlet, the APH outlet or First (or Old) ESP inlet, between the two ESPs, and at the Second (or New) ESP outlet or stack. Fig. 1 shows an isometric view of the back-end configuration of Unit A.

Unit B is a corner-fired pulverized coal unit burning an Eastern US bituminous coal with a nominal, full load rating of 108 MW. The average Hg coal concentration for the fuel fired at this unit is 0.07 ppm_w. This unit is equipped with four mills that supply coal to four elevations of conventional burners. The particulate control equipment at this unit consists of one hot-side ESP and one cold-side ESP at both sides of a tubular air preheater. Hg sampling at this unit was conducted at four locations along the convective pass. These locations correspond to points at the Hot ESP inlet, Hot ESP outlet or APH inlet, APH outlet or Cold ESP inlet, and Cold ESP outlet or stack.

For Units A and B, three PS Analytical (PSA) Sir Galahad Hg semi-continuous emission monitors (SCEMs) were used for speciation of gaseous Hg measurements at the different locations in the convective pass, except at the stack. Baldwin inertial filter probes were used for sample conditioning. The Sir Galahad Hg SCEM uses a wet chemistry system to pre-treat the flue gas and convert all forms of Hg to elemental Hg. The pretreatment system, Model S235C400, manufactured by PSA, splits the incoming flue gas into two streams. One stream passes through a KCl solution, which removes Hg^{2+}, thus allowing only Hg^0 to reach the detector. The other stream passes through a stannous chloride ($SnCl_2$) solution, which converts the Hg^{2+} to Hg^0, thus facilitating the measurement of total Hg. Given, that SO_2 interferes with the ability of $SnCl_2$ to reduce Hg, a pretreatment step is included to remove SO_2 using sodium hydroxide. The PSA instrument is based on the principle of atomic fluorescence and uses a gold-impregnated silica support, operating on a cycle consisting of constant temperature pre-concentration of the Hg in the flue gas, and heating to 485 °C for Hg desorption. The total time for the entire process is of approximately 5 min (sampling frequency). The system calibration uses Hg^0 as the primary standard. The Hg^0 is contained in a closed vial, which is held in a thermostatic bath. The temperature of the Hg is monitored, and the amount of Hg is measured using vapor pressure calculations. Typically, the calibration of the unit proves stable over a 24-h period.

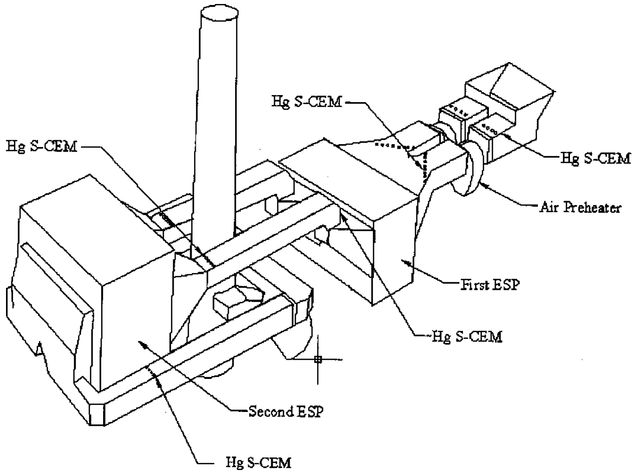

Fig. 1. Unit A—isometric view of back-end configuration.

A Nippon DM-6 (non speciating) instrument was used in the tests at Units A and B for total Hg measurement at the stack. The Nippon DM-6 is a 'dry' system. In a pre-treatment unit, sample gas is drawn from the stack and passed through a filter to remove dust. The Hg compounds are then reduced to Hg^0 by contacting with a solid-state reduction catalyst, which is housed in the probe. The sample gas with the reduced elemental Hg then passes through a chiller to remove moisture and then transported to the detector via Teflon tubing to be continuously measured by cold vapor atomic absorption spectrometry (CVAAS). The Hg concentration sampling frequency was set at every second. The response time used was less than one minute and the sensitivity 0.1 $\mu g/m^3$.

Particulate-bound Hg in the fly ash and coal samples was measured using a Leco AMA-254 Hg Analyzer. This instrument works based on the principle of atomic absorption spectrometry, and is designed for direct Hg determination in solid and liquid samples without the need of sample chemical pre-treatment. A sample of a known weight is placed on a sampling tray and introduced into a catalytic tube. By controlled heating of a decomposition furnace, the sample is first dried and then thermally decomposed, or burned. The decomposition products of the sample are carried out by an oxygen stream to the second part of the catalytic tube. Here, the oxidation is finalized and halogens, nitrogen and sulfur oxides are trapped. The decomposition products are then carried out to an amalgamator for selective trapping of Hg. After this step, the amount of Hg trapped in the amalgamator is measured. The range of measurement for the AMA-254 Hg Analyzer is 0.05–600 ng of Hg, the detection limit is 0.01 ng of Hg, and the typical analysis time for a single measurement is 5 min.

3. Test results and discussion

The test program at each unit consisted of Hg emissions baselining and a series of parametric tests at full unit generation load. Parametric testing involved individual changes to boiler control settings, while keeping other pertinent parameters at baseline conditions. Enough time was provided for each test to accommodate the transient in unit conditions, reach steady-state operation at the test condition and collect representative operating data and fly ash samples. The parameters investigated included the excess O_2 level, OFA register settings (Unit A), mill loading and out-service configuration, APH back-end temperature and ESP field energization.

‘As-fired’ composite coal samples were obtained three times a day for documentation of the coal Hg content (level and variability). Unit coal samples were collected from sample ports at the inlet of each of the belt feeders. Fly ash samples were collected for each test. Unit A fly ash samples were collected from selected hoppers at the appropriate test-side of the First and Second ESP hoppers. For each test run, an effort was devoted to empty each hopper and load it with ash representative of the test run. Unit B fly ash samples were collected from four hoppers at the Hot ESP and also from automatic CEGRIT® sampler probes located at the economizer outlet. The CEGRIT® samplers uses the differential pressure between the inner gas duct and the ambient to continuously extract a particle-laden sample from the gas stream at isokinetic conditions. The sample passes through a cyclone, which captures the fly ash, while discharging the gas back into the main stream.

Real-time electronic data from the Hg SCEMs were continuously recorded for gaseous Hg concentrations (total and elemental Hg) in the flue gas. In addition, plant performance and stack emissions data were collected using the plant PI System data acquisition software.

3.1. Unit A results

Fig. 2 shows the baseline results for Unit A. The baseline conditions represent typical operating settings used by the operators and include four mills evenly loaded and economizer excess O_2 at 3.5%. Fig. 2 shows baseline Hg data along the different sampling locations in the convective pass, including elemental and oxidized Hg in the flue gas, particulate-bound Hg in the fly ash, as well as the Hg concentration in the coal for the particular test run. Gaseous Hg concentrations were normalized to 3% O_2. Since the Hg-SCEMs did not directly measure Hg^{2+}, it is derived by the difference between total Hg and elemental Hg. Hg concentration in the coal was measured to be 0.052 ± 0.006 ppm_w for all the field tests performed at Unit A.

Results displayed in Fig. 2 show that gaseous Hg speciation is dominated by oxidized Hg at the APH inlet, accounting for 84% of the total Hg in the flue gas. Across the APH, total gaseous Hg remained relatively unchanged within the range of measurement uncertainty, and Hg^0 was reduced from approximately 1.3 to 0.4 μg/dscm, resulting in a 69% Hg^0 reduction. Hg^{2+} concentration decreased from approximately 6.9 to 2.0 μg/dscm across the Old ESP, indicating large heterogeneous adsorption of Hg^{2+} onto the fly ash. This was consistent with an increase in particulate-bound Hg in the fly ash from approximately 0.3 to 1.5 ppm_w between the ash hoppers at both ESPs. There also appeared to be a small increase in Hg^0 across the First ESP, with the average increasing from 0.4 to 1.2 μg/dscm (Fig. 2). However this apparent increase may be the result of the interaction of the Hg in the flue gas across the ash collected on the sampling line filters, and due to some deabsorption of elemental Hg from the fly ash in the precipitator. The total gaseous Hg concentration at the stack was approximately 1.5 μg/dscm. The overall baseline removal efficiency, defined as the Hg reduction from the APH inlet to the stack, was approximately 82%.

Parametric test results for different conditions that involved changes to the combustion side: excess O_2, OFA register settings and mills in-service are shown in Fig. 3. The results in

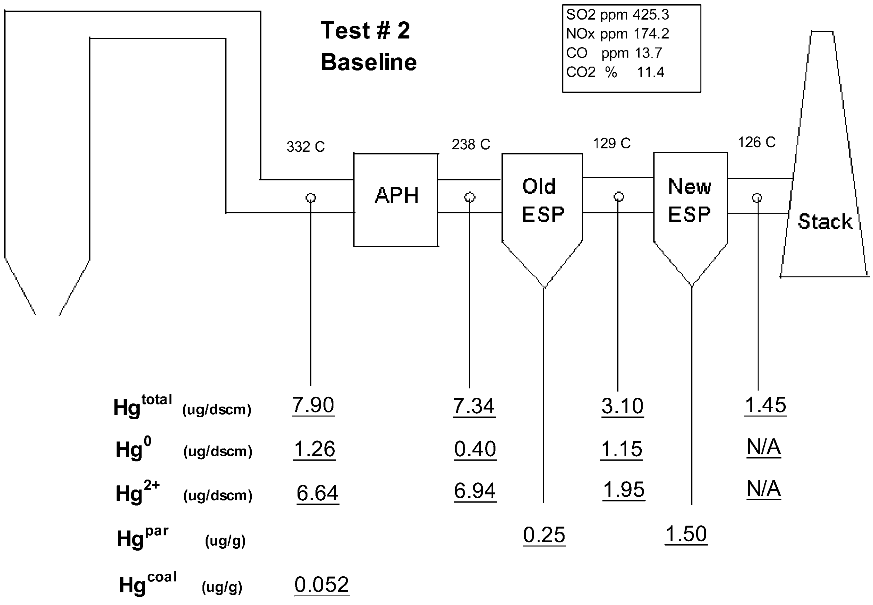

Fig. 2. Unit A—baseline Hg speciation along the boiler convective pass.

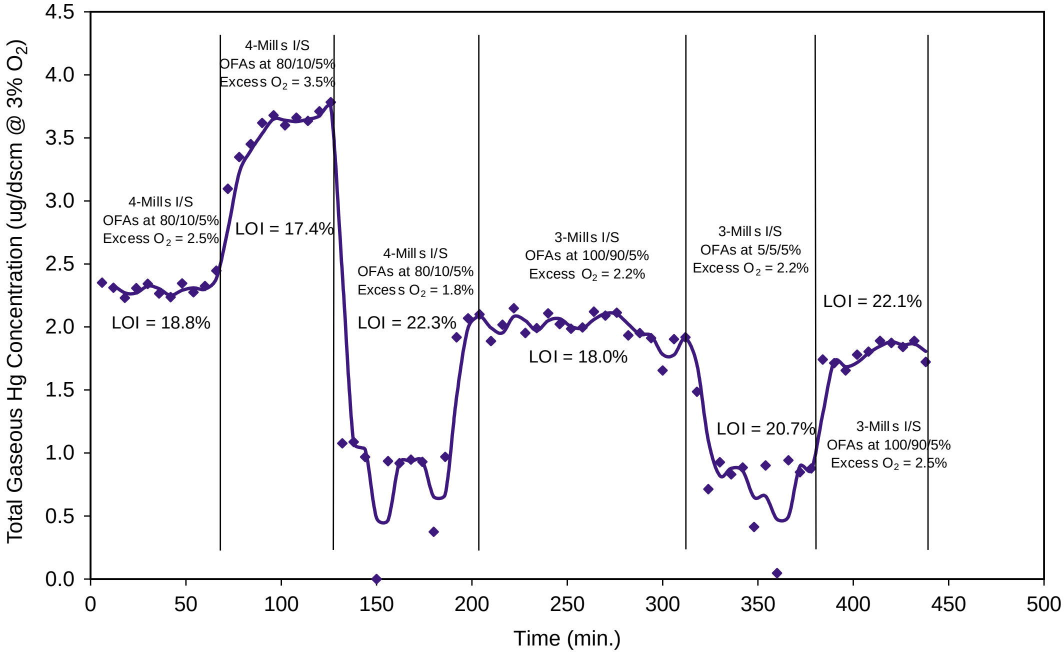

Fig. 3. Unit A—Hg SCEM analyzer response to combustion modifications.

Fig. 3 correspond to total gaseous Hg measurements at the Old ESP outlet (New ESP inlet) and are correlated with the fly ash loss on ignition (LOI) results from samples collected from the Old ESP hoppers. For simplification, the time-series data in Fig. 3 do not include the transient time between tests. The results of Fig. 3 indicate that excess O_2 and OFA register settings have an impact on mercury in direct relation to their impact on the fly ash LOI level. For this particular case, lower excess O_2 conditions reduce the availability of air in the furnace for char burnout, resulting in incomplete combustion and increased levels of unburned carbon in the ash. The effect of the OFA registers on unburned carbon is, most likely, due to their function of helping to complete combustion, with opening of the OFA registers resulting in better carbon burnout and reduced levels of fly ash LOI. The impact of four-mill vs. three-mill in-service configuration on fly ash LOI and, consequently, on Hg was found of second order, in comparison to the impact of excess O_2 and the OFA registers. This may not be the resulting impact on other units where the coal handling and grinding capacity of the mills is challenged when switching to a 1-mil out-of-service configuration and changes are made to the classifier settings or dynamic classifier speed.

Fig. 4 summarizes the direct connection between combustion modifications, fly ash LOI, and Hg emissions. Gaseous stack Hg emissions were reduced by approximately 50% by increasing fly ash LOI from 17 to 22%, resulting in an increase in the ‘naturally-occurring’ Hg removal efficiency (baseline removal of Hg before any boiler operation modification) from 82 to 94%. The concentration of Hg in the fly ash consistently increased for that change in LOI by approximately 60%. This is consistent with studies that have indicated that Hg enrichment in fly ash often correlates directly with fly ash carbon content, and increases by extending the effective contact time between flue gas and fly ash [11]. As the excess O_2 in the boiler was manipulated down to cause an increase in fly ash LOI at Unit A, the flue gas residence time also increased at temperatures at the back-end of the boiler where Hg capture into the fly ash is adequate (below 400 °C). Furthermore, experimental results on characterization of the effect of flue gas constituents on Hg sorption on fly ash and activated carbon have indicated that a decrease in the concentration of NO_x in test gas enhances the capture of Hg^0 into the fly ash [12]. Tests performed at Unit A confirm these results, given that reductions in excess O_2 result in NO_x emissions reductions, which should enhance Hg^0 capture into the fly ash.

The range of NO_x and CO emission levels for the change in gaseous stack Hg emissions from approximately 1.5 to 0.5 μg/dscm, was 174–153 ppm_v, and 11–98 ppm_v, respectively. The maximum reduction in Hg emissions was associated with a unit heat rate increase of 83 Btu/kWh. This change in heat rate was calculated based on the incremental change in

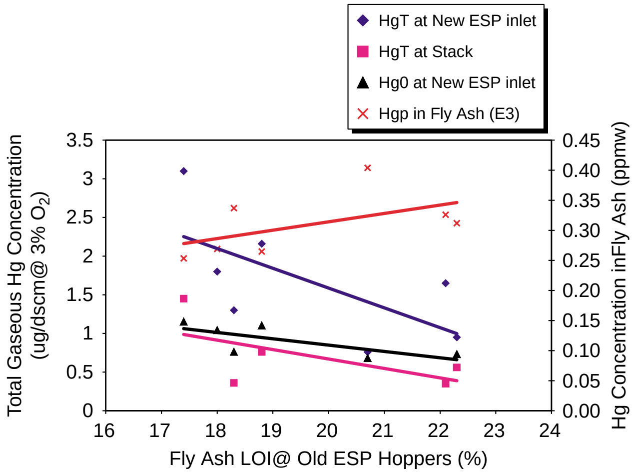

Fig. 4. Unit A—summary of mercury reduction vs. fly ash LOI.

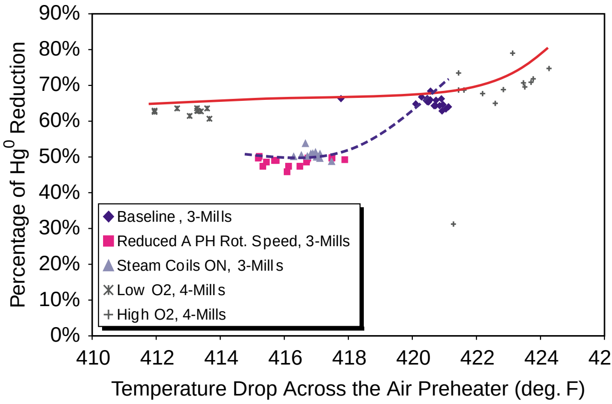

Fig. 5. Unit A—elemental mercury oxidation response to APH operation modifications.

unit heat rate due to the impact of the different operating conditions on flue gas outlet temperature, CO and LOI levels and excess O_2 or stack losses. Given the double-ESP configuration on Unit A, no significant changes to stack opacity were noticed from these changes. This may not be the case for other units that are ESP capacity limited and will see their ESP collection efficiency affected by the changes in fly ash UBC.

Parametric test results for different conditions that involved changes to the air preheater at Unit A are shown in Fig. 5. Changes to the APH gas temperature profile were achieved by preheating the inlet air using a set of steam coils and by manipulating the rotational speed of the APH, on-line. Also included in Fig. 5 are the results, expressed as the percentage of Hg^0 oxidation across the APH vs. flue gas temperature drop, corresponding to high and low excess O_2 operation. The data in Fig. 5 confirm that control settings that result in larger flue gas quenching across the APH, result in enhanced elemental Hg oxidation in this part of the convective pass. This can be explained through the known mechanism for the homogenous gas phase chemistry of Hg [13]. The reaction that is believed to be responsible for homogenous Hg oxidation is: $Hg^0 + Cl + M \rightarrow HgCl + M$. Hence, the concentration of Cl in the flue gas is very important for Hg oxidation. As the flue gas is quenched in the APH from approximately 370 to 150 °C, the reaction: $Cl + H_2O \leftrightarrow OH + HCl$ is suggested to proceed in the reverse direction, resulting in an increase in the concentration of the Cl radical and enhancement of elemental Hg oxidation. Ref. [13] has pointed to modeling results on Hg chemistry that indicate spikes in chlorine radical concentration in regions of the boiler where the flue gas cooling rates are high. It should be added that, it has been found that the capture of Hg on fly ash is progressively increased as the flue gas temperature is reduced below the 400 °C level [11]. The reduction in APH gas outlet temperature should also be accompanied by increased Hg capture.

The impact of the other boiler parameters investigated in the tests at Unit A revealed that a combination of combustion control settings can be found which produces a major impact on the overall Hg emission situation, while minimizing its impact on unit constraints, such as NO_x emissions and unit performance. For Unit A, it was also found that together with excess O_2, OFA registers settings, and mill out-service configuration, ESP power levels have a first order effect on Hg emissions. Fig. 6 shows the impact of de-energization of the collection fields in the first or Old ESP had on the elemental and total Hg at the stack. The modification in the operation of the particulate collection train produced reductions in mercury

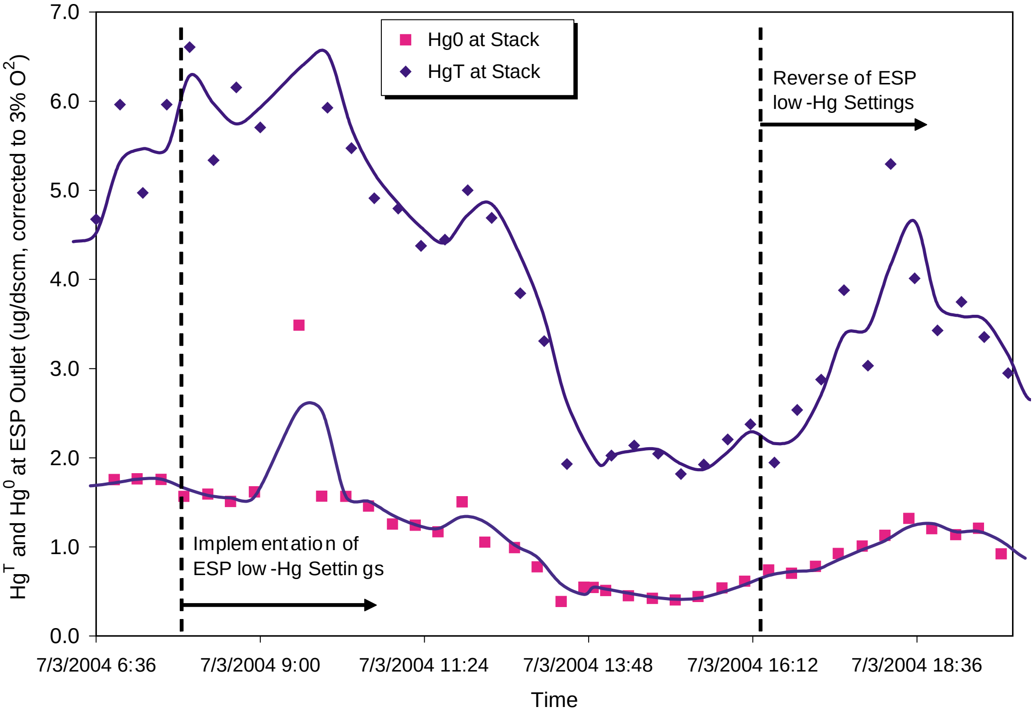

Fig. 6. Unit A—total and elemental stack mercury emissions vs. ESP energization modification.

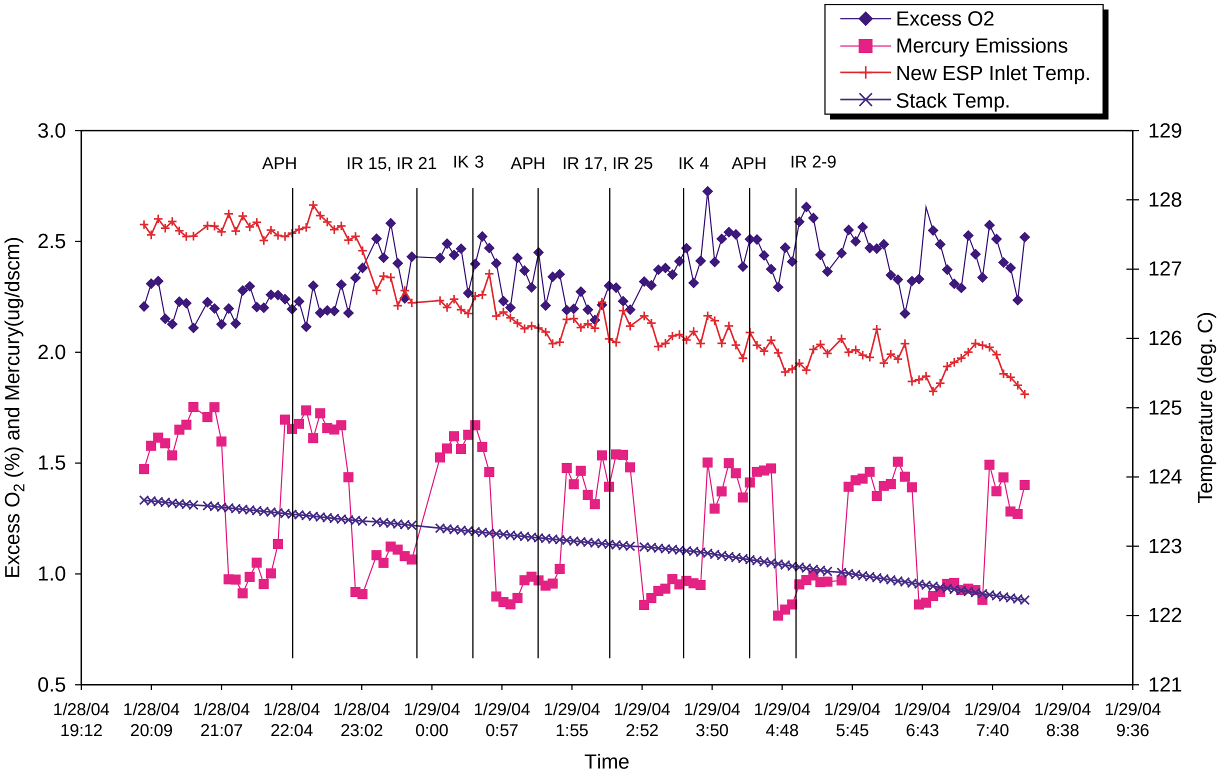

Fig. 7. Unit A—impact of boiler sootblowing on mercury emissions.

emissions after approximately 7 h of continued operation at the modified conditions. These conditions, most likely, promoted Hg sorption into the fly ash by extending the residence time for the gas and solid, for effective in-fly capture of the Hg in the flue gas.

A final aspect that provided additional contribution to Hg emission reduction was found to be sootblowing. Fig. 7 shows elemental and oxidized Hg data at the New ESP inlet in response to aggressive APH, waterwall (IRs type rotative blowers) and convective pass sootblowing (IKs type retractible blowers). At constant unit load and excess O_2 conditions, diligent sootblowing resulted in reductions in gas temperature and Hg emissions. It should be mentioned that no significant SCEM Hg analyzer drift was found for the test period in Fig. 7. The relation between the reduction in flue gas temperature, motivated by the enhanced heat transfer in the convective sections of the boiler (due to the cleaner heat transfer surfaces), and Hg capture into the fly ash is consistent with the discussion presented in the preceding paragraphs and results of Ref. [14] that indicates the value reduced gas temperatures have on Hg capture on fly ash.

3.2. Unit B results

Fig. 8 shows the baseline results for Unit B. This condition, representing boiler control settings typically used by the operators, is characterized by four mill operation and an economizer excess O_2 of 2.7%. All the Hg-SCEMs at the four sampling locations at this unit (Hot ESP inlet, APH inlet, Cold ESP inlet and stack) were set to operate on total gaseous Hg, solely. The baseline test showed that Hg^0 accounted for less than 10% of the total gaseous Hg in average for a 24-h period. Therefore, tests on Unit B were focused on investigating the effect of boiler operation on heterogeneous Hg adsorption by fly ash. Fig. 8 shows that total gaseous Hg decreases along every piece of equipment along the convective pass, indicating corresponding Hg adsorption into the fly ash. Baseline Hg_p in the fly ash at the inlet of the Hot ESP was measured at 0.029 ppm_w. Baseline fly ash LOI at the economizer outlet was measured to be 6.7%. The average Hg content in the coal was 0.073 ± 0.016 ppm_w for all the field tests performed at Unit B. The overall baseline removal efficiency, defined as the Hg reduction from the APH inlet to the stack, was approximately 20%.

Excess O_2 tests and resulting fly ash LOI and Hg emission levels are shown in Fig. 9. The results correspond to total gaseous Hg measurements at the stack and are correlated with the fly ash LOI results from samples collected from the automatic CEGRIT® samplers. In Fig. 9, gaseous stack Hg emissions were reduced by approximately 57%, over the range of excess O_2 tested at Unit B, by increasing fly ash LOI from approximately 7 to 18%, resulting in an increase in the 'naturally-occurring' Hg removal efficiency from the 20% level to a removal efficiency of 38%. The concentration of Hg in the fly ash consistently increased for that change in LOI. This can also be seen in Fig. 9, where the Hg_p concentration in the fly ash almost doubled due to the increase in fly ash LOI. These results are consistent with the results for Unit A and the references annotated above, that indicate that fly ash from certain bituminous coals can effectively adsorb in-flight Hg

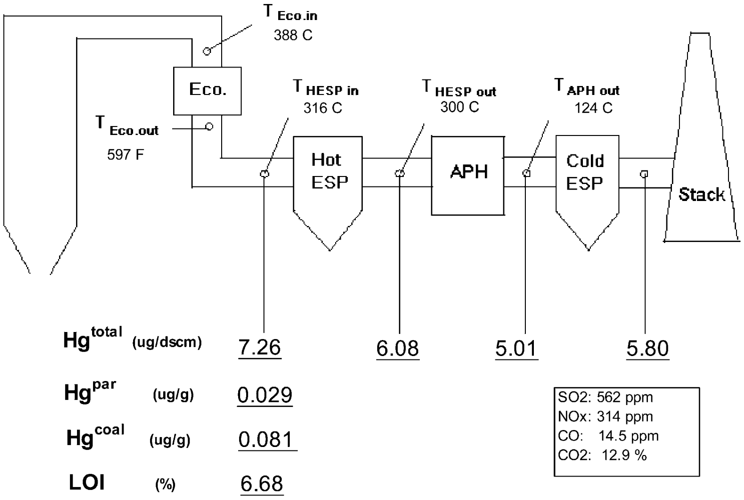

Fig. 8. Unit B—baseline Hg speciation along the boiler convective pass.

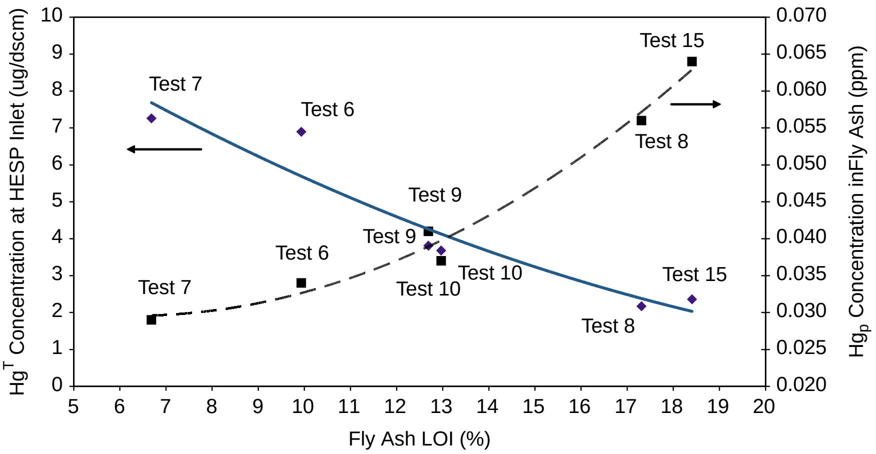

Fig. 9. Unit B—summary of mercury reduction vs. fly ash LOI.

compounds from the flue gas, and that this effect is enhanced at higher unburned carbon levels. The range of NO_x and CO emission levels for the change in gaseous stack Hg emissions was approximately 314–270 ppm_v, and 15–60 ppm_v, respectively. The change in Hg emissions was associated to a unit heat rate increase of 43 Btu/kWh. No increase in stack opacity over the 20% prescribed limit for Unit B resulted for the operating conditions used in these tests.

The results of the tests performed on Unit B for other boiler parameters, such as burner tilt and air preheating did not show the level of impact achieved with the excess air parameter. This may be related to the configuration of the burner system (conventional burner), which does not work under heavy staging, as the low-NO_x system of Unit A.

4. Conclusions

Full-scale testing was performed at two coal-fired units burning bituminous coals to investigate the feasibility of affecting mercury emissions from coal-fired plants by manipulating boiler control settings. The results of these tests demonstrate the merit of modifying boiler operation through changes to combustion, air preheater and ESP operation to beneficially influence the behavior of Hg in the boiler convective pass and reduce stack gaseous mercury emissions. The same combination of settings typically results in added NO_x emissions reductions and small penalties in unit heat rate. A strategy for mercury control by selectively manipulating boiler control settings, if used in combination with other control measures such as sorbent injection, can provide a reduced-cost option for mercury control. It is important to note that these findings are based on a relatively small data set and, thus, should be considered preliminary rather than final conclusions. Although, the impact on mercury emissions from boiler control settings are directly related to the thermochemical conditions of the flue gas and fly ash characteristics, this effect is site-specific. More testing is needed at other units to determine weather the trends observed in these tests can be extended to other boilers designs and fuel blends.

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