MULTI-POLLUTANT EMISSIONS CONTROL: PILOT PLANT STUDY OF TECHNOLOGIES FOR REDUCING Hg, SO_3, NO_X AND CO_2 EMISSIONS

Final Technical Report
For The Period September 5, 2001, through May 30, 2005

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ABSTRACT

A slipstream pilot plant was built and operated to investigate technology to adsorb mercury (Hg) onto the existing particulate (i.e., fly ash) by cooling flue gas to 200-240 °F with a Ljungstrom-type air heater or with water spray. The mercury on the fly ash was then captured in an electrostatic precipitator (ESP). An alkaline material, magnesium hydroxide ($Mg(OH)_2$), is injected into flue gas upstream of the air heater to control sulfur trioxide (SO_3), which prevents acid condensation and corrosion of the air heater and ductwork. The slipstream was taken from a bituminous coal-fired power plant. During this contract, Plant Design and Construction (Task 1), Start Up and Maintenance (Task 2), Baseline Testing (Task 3), Sorbent Testing (Task 4), Parametric Testing (Task 5), Humidification Tests (Task 6), Long-Term Testing (Task 7), and a Corrosion Study (Task 8) were completed. The Mercury Stability Study (Task 9), ESP Report (Task 11), Air Heater Report (Task 12) and Final Report (Task 14) were completed. These aspects of the project, as well as progress on Public Outreach (Task 15), are discussed in detail in this final report.

Over 90% mercury removal was demonstrated by cooling the flue gas to 200-210 °F at the ESP inlet; baseline conditions with 290 °F flue gas gave about 26% removal. Mercury removal is sensitive to flue gas temperature and carbon content of fly ash. At 200-210 °F, both elemental and oxidized mercury were effectively captured at the ESP. $Mg(OH)_2$ injection proved effective for removal of SO_3 and eliminated rapid fouling of the air heater. The pilot ESP performed satisfactorily at low temperature conditions. Mercury volatility and leaching tests did not show any stability problems. No significant corrosion was detected at the air heater or on corrosion coupons at the ESP. The results justify larger-scale testing/demonstration of the technology. These conclusions are presented and discussed in two presentations given in July and September of 2005 and are included in Appendices E and F.

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INTRODUCTION

Coal-fired electric generating plants are the largest source of anthropogenic mercury (Hg) emissions in the U.S. The U.S. Environmental Protection Agency (EPA) issued the Clean Air Mercury Rule in March 2005 to reduce these emissions.

Technologies are available to reduce Hg emissions from coal-fired power plants, although no technology currently available eliminates Hg emissions uniformly across the spectrum of power plant configurations and coal types. The current leading technology is powdered activated carbon (PAC) injection, also known as activated carbon injection (ACI). Authors from the U.S. Department of Energy (DOE) and EPA project control costs via PAC injection for most plants to be 0.3-1.9 mills/kWh.[1] This is equivalent to $4,500 to $29,000 per pound of mercury controlled at a plant burning 12,000 Btu/lb coal containing 0.1 ppm Hg at a heat rate of 10,000 Btu/kWh, and equipped to control 80% of the mercury emissions. Other pollution control technologies can remove Hg from flue gases as a "co-benefit." For example, flue gas desulfurization (FGD) systems in combination with electrostatic precipitators (ESPs) can reduce smoke stack mercury emissions from units firing bituminous coal by 50% to 70% (typically about 65%).[2] Available information indicates that the combination of selective catalytic reduction (SCR) with FGD and ESP systems can provide ~75-90% Hg emissions reduction from units firing bituminous coal

CONSOL Energy Inc., Research & Development (CONSOL) and Allegheny Energy Supply Company, LLC, with support from DOE's National Energy Technology Laboratory (NETL), conducted a three-and-a-half year program to construct and operate a 1.7 MWe equivalent pilot plant using flue gas from a coal-fired power generating station to develop an innovative technology for reducing mercury emissions from coal-fired power plants. Other participants are Alstom Power, Inc.; Environmental Elements Corp.; and Carmeuse Lime, Inc. The concept behind this technology is to adsorb Hg on the existing particulate (e.g., fly ash) by cooling the flue gas to 200-240 °F with the air heater or with water spray. The fly ash and mercury then are captured in the power plant's existing particulate collection device. An alkaline material, magnesium hydroxide ($Mg(OH)_2$), is injected into flue gas upstream of the air heater to capture sulfur trioxide (SO_3) to prevent corrosion of the power plant's air heater and ductwork. The $Mg(OH)_2$ for the pilot plant tests is a by-product slurry from the Thiosorbic Lime scrubber at the Allegheny Energy Pleasants Station. The test program included a series of short-term tests to determine performance, long-term tests to evaluate the impact of the technology on the performance of specific power station components, and mercury stability tests on the collected fly ash.

CONSOL's prior development work suggested that this concept could be successful for controlling Hg emissions. Tests on the CONSOL pilot-scale combustor gave as much as 90% Hg removal when firing Illinois coal, depending on gas temperature and ash carbon content.[3] Bench-scale work conducted by CONSOL showed that FGD by-product $Mg(OH)_2$ slurry is an active sorbent for SO_3 at economizer outlet temperatures.[4]

There are several potential benefits of the technology:

- The technology could most importantly provide 70-90% Hg removal at a projected cost that is an order of magnitude lower (on a $/lb Hg removed basis) than PAC injection;
- The technology is conceptually suitable for retrofitting to existing plants or for new plants;
- The technology will reduce the emissions of SO_3, a precursor of secondary fine particulate matter. This will reduce emissions reportable under the Toxic Release Inventory, and ameliorate any associated visible plume problem. The removal of SO_3 also benefits the use of SCR and selective non-catalytic reduction installations by preventing the formation of ammonium bisulfate fouling deposits, which are sometimes problematic with these technologies.
- The technology can also allow approximately 2% improved generating efficiency (for those power stations equipped with a sufficiently large air heater), which would lead to 2% lower emissions (on a lb/kWh basis) of most pollutants and carbon dioxide. The improved efficiency could lead to savings in fuel cost of ca. $600,000/y for 600 MW plant; this would essentially offset the costs of the $Mg(OH)_2$.

The concept behind this technology is to adsorb mercury (Hg) onto the existing particulate (i.e., fly ash) by cooling the flue gas to 200-240 °F with the air heater or with water spray. The mercury on the fly ash is then captured in the power plant's existing particulate collection device. An alkaline material, magnesium hydroxide ($Mg(OH)_2$), is injected into flue gas upstream of the air heater to control sulfur trioxide (SO_3), which prevents acid condensation and corrosion of the power plant air heater and ductwork. See Figure 1.

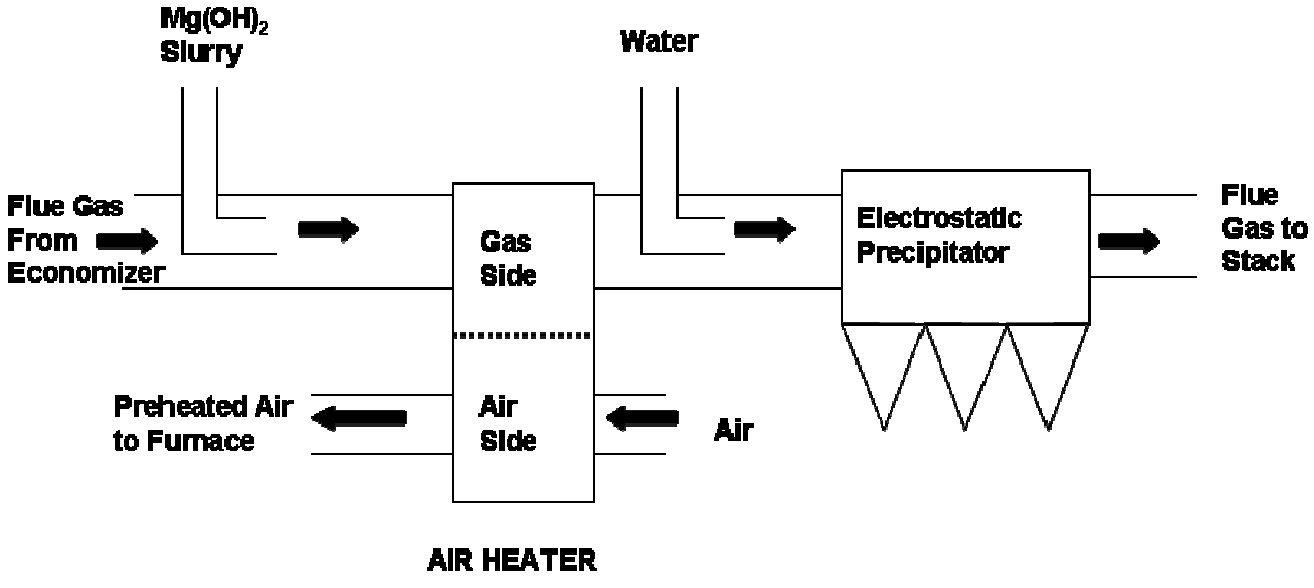


Figure 1. Conceptual Schematic of Mercury Control Process

The goals of the pilot plant program were to:

- Determine the ability of the process technology to remove Hg and to evaluate Hg removal by species
- Determine the optimum operating conditions for effective Hg control
- Determine the optimum sorbent rate for effective SO_3 control
- Determine the impact of reduced cold-end temperature and SO_3 control on air heater performance and corrosion
- Determine the stability of the captured Hg toward leaching and volatilization
- Disseminate project information

EXECUTIVE SUMMARY

CONSOL Energy Inc., Research & Development (CONSOL) and Allegheny Energy Supply (AES), with support from the U.S. Department of Energy's National Energy Technology Laboratory, conducted a three-year program to construct and operate a 1.7 MWe equivalent pilot plant using flue gas from a coal-fired power generating station to develop an innovative technology for reducing mercury emissions from coal-fired power plants. The technology works by deeper cooling the exhaust gases with the air heater or water spray and permitting the mercury to adsorb on the fly ash. The fly ash and mercury are then captured in the power plant's existing particulate collection device. An alkaline material (magnesium hydroxide slurry) is injected to remove sulfur trioxide and prevent corrosion, fouling of the power plant air heater and ductwork.

At baseline conditions (300 °F ESP inlet), mercury removal was about 25%. Based on pilot plant results, a projected 90% mercury removal could be achieved in a full-scale plant by burning 10% ash coal with fly ash carbon (LOI) of 8% and 200 °F flue gas at the ESP inlet. 61 to 96% ESP mercury removal was demonstrated with cooling via air heater to 200-210 °F at the ESP inlet and fly ash carbon content of 6 to 15% during test runs up to 75 hours long. 61 and 76% ESP mercury removal was demonstrated with limited cooling via water spray to 200-210 °F at the ESP inlet and fly ash carbon content at a limited and relatively low range of 6 to 7% during test runs up to 4 hours long. Mercury removal with the ESP is improved with decreased ESP inlet temperature and higher unburned carbon content in the fly ash.

$Mg(OH)_2$ slurry injection between the economizer and air heater was effective for removal of sulfur trioxide and in turn eliminated fouling of the air heater elements for test periods of up to 75 hours with no soot blowing and flue gas outlet temperatures of 225-230 °F. A molar ratio of 4:1 Mg/SO_3 effectively reduced air heater inlet flue gas concentration to 3 ppmv or less which was considered adequate to prevent air heater fouling. Pilot ESP performance was not adversely affected by SO_3 reductions and low temperature operation via air heater cooling. Water spray cooling led to high-voltage insulation failures which shortened the test runs to 4 hours. The failures were due to a non-standard arrangement of the insulation in the pilot ESP. Particulate removals by the ESP of 99+% were achieved during all of the test conditions.

Mercury volatility and leaching tests did not show any stability problems. No significant corrosion was detected at the air heater or on corrosion coupons at the ESP. The results justify larger-scale testing/demonstration of the technology.

These conclusions are presented and discussed in two presentations given in July and September of 2005 and are included in Appendices E and F.

EXPERIMENTAL

Host Plant

The host site for the pilot plant was Allegheny's Mitchell Station in Courtney, PA. The technology was tested on a 16,500 lb/h (3640 scfm, equivalent to 1.7 MWe) slipstream of the flue gases from the 288-megawatt, coal-fired Unit No. 3. Unit 3 entered service in 1963. It is corner-fired, and equipped with a Thiosorbic Lime* wet flue gas desulfurization system and an electrostatic precipitator, but not with a selective catalytic reduction system. The station typically burns northern Appalachia bituminous coal. The range of values of some important characteristics of the coal burned during the pilot plant tests are as follows: sulfur content, 3.0 – 4.8% dry basis; chlorine, 0.05 – 0.09% dry basis; ash content, 9.3 – 15% dry basis; mercury content, 0.09 – 0.13 mg/kg (ppm) as determined basis.

Pilot Plant

Figure 2 shows the connections of the pilot plant to the host plant and the arrangement of the pilot plant equipment. Appendix B contains a detailed description of the pilot plant and test program. The Ljungstrom-type pilot air heater was sized to be sufficiently large for accurate performance evaluations. As a result, it is sized for a considerably higher gas throughput than the pilot ESP can handle. Therefore, as shown in Figure 2, the pilot plant splits off the excess flue gas between the two devices to maintain acceptable flow rates for both. For the tests described here, flue gas flow rates were about 14,000 lb/hr (~ 3100 scfm) at the air heater inlet and about 3,900 lb/hr (~950 scfm) at the ESP inlet. The gas and fly ash sampling Locations are indicated in Figure 2 by the symbol ⊗.

For most of the tests described here only two of three ESP fields were operating yielding a specific collection area of about 123 ft^2/1000 acfm for the pilot ESP. The voltage, current and spark rate of each high-voltage power supply were periodically recorded to evaluate the performance of the pilot ESP.

Referring to Figure 2, the gas residence times between Location A and Location H is 1.9 s; between H and B is 0.75 s; between B and E is 1.6 s; between E and F is 2.3 s; and between F and G is 7.3 s (assumes the temperature is constant except for a drop across the air heater from 600 °F to 240 °F, and flow rates as described above). The flue gas temperature dropped 10 to 20 °F from Location B (air heater outlet) to Location F (ESP inlet) depending on ambient temperature conditions. The distance from Location B to F is about 150 feet.

Flue gas was sampled to determine Hg, particulate matter (PM), sulfur dioxide (SO_2), and SO_3, and Hg was speciated into elemental, oxidized, and particulate Hg at the inlets

* Some Thiosorbic Lime units can be configured as a Thioclear system, which can produce by-product magnesium hydroxide. Mitchell Station is not so configured; however, Pleasants Station, the source of our magnesium hydroxide, is.

and outlets of the air heater and ESP via the Ontario Hydro method (ASTM D-6784-02). All SO_3 sampling was conducted using the controlled condensation sampling method. Pilot plant ESP fly ash was also sampled for mercury and carbon determinations. Samples of the coal and ESP fly ash from the host plant were also analyzed for a variety of properties. Coal, fly ash, and gas sampling data from the test program are included in Appendix A and the Results and Discussion section of this report.

The $Mg(OH)_2$ used in the pilot plant tests is a by-product slurry from the Thiosorbic Lime scrubber at the Allegheny Energy Pleasants Station in Willow Island, WV. The slurry was transported to Mitchell Station as a concentrate; it was diluted with water prior to injection into the 20" duct to facilitate atomization through the air/slurry nozzle.

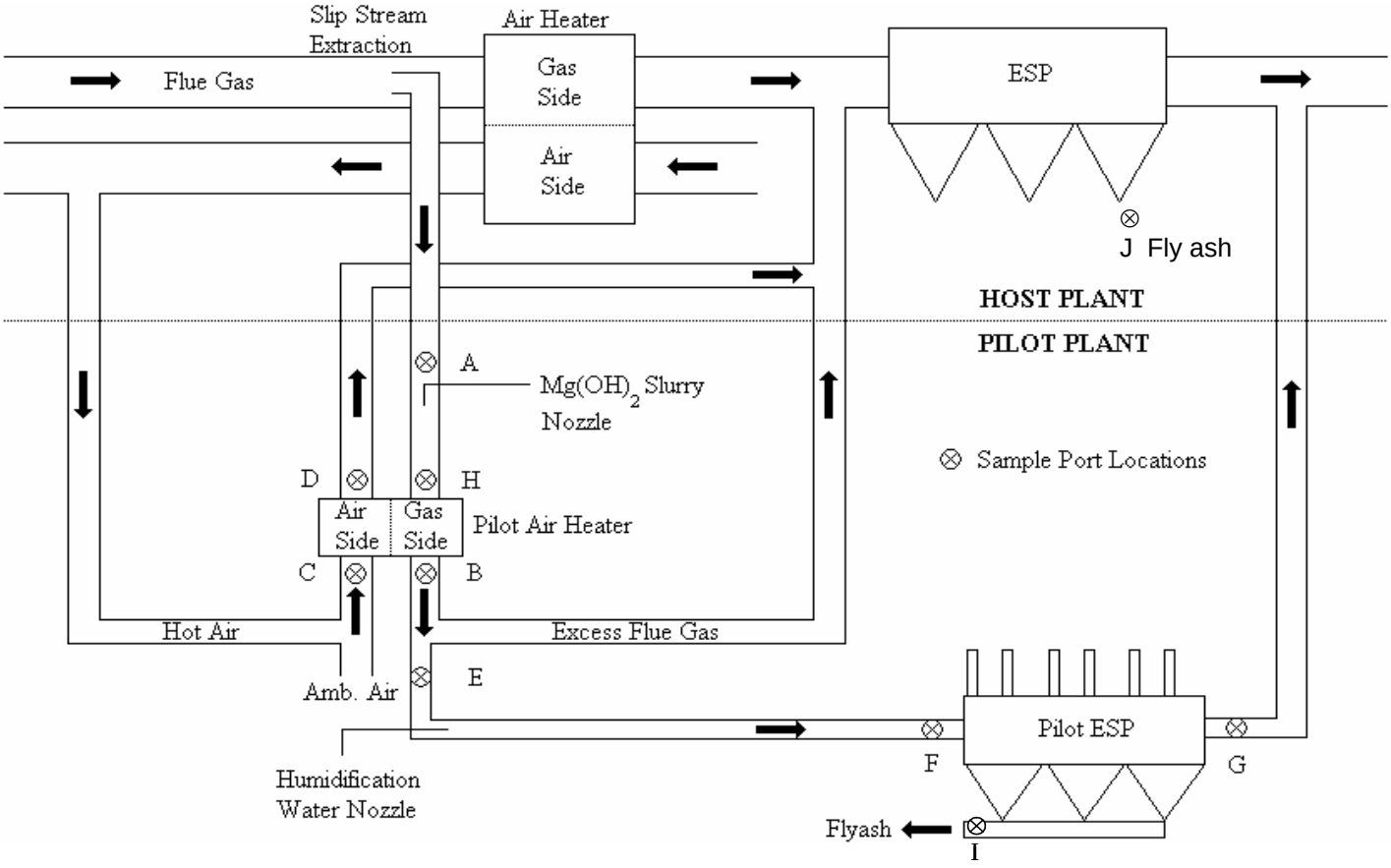


Figure 2. Process Schematic with Sampling Locations of CONSOL/Allegheny Mercury Control Pilot Plant

Project by Task

The project consisted of the following twelve tasks:
Task 1 - Design, Fabrication, and Installation of Pilot Plant
Task 2 - Pilot Plant Start Up and Testing Program Maintenance
Task 3 - Baseline Testing
Task 4 - Sorbent Evaluation - SO_3 Control

Task 5 - Parametric Testing - Hg Removal
Task 6 - Flue Gas Humidification Testing – Hg Removal
Task 7 - Long-Term Testing – SO_3 and Hg Removal
Task 8 - Corrosion Study
Task 9 - Stability of Hg on Fly Ash
Task 11 - Report on ESP Operation and Performance
Task 12 - Report on Air Heater Operation and Performance

The test program started with long-term baseline tests followed by short-term tests for sorbent evaluation for SO_3 control with parametric and humidification testing for mercury removal to establish operating conditions for the long-term tests; and finally long-term tests for SO_3 control and mercury removal to evaluate the impact of the technology on the performance of the air heater and ESP, corrosion of plant components, and stability toward leaching and volatilization of the Hg collected with the fly ash. The pilot plant was operated at three main sets of flue gas temperature conditions:

1. 280-300 °F at ESP inlet during baseline tests, similar to the host plant conditions with no magnesium hydroxide injection. The pilot plant was operated up to 123 hours continuously.
2. 230-250 °F at ESP inlet by cooling of the flue gas via the air heater or water spray, and injection of magnesium hydroxide at a molar ratio of 2:1 to 5:1 during sorbent evaluation for SO_3 control, parametric and humidification testing for mercury removal. The pilot plant was operated up to 13 hours continuously with magnesium hydroxide injection during each day of short-term testing.
3. 200-210 °F at ESP inlet by deep cooling of the flue gas via the air heater or water spray, and injection of magnesium hydroxide at a molar ratio of approximately 4:1 during long term testing for SO_3 and mercury removal. The pilot plant was operated up to 75 hours continuously with air heater cooling and up to 4 hours with water spray cooling at long-term conditions.
4. During all testing the flue gas temperature at the air heater outlet was 10 to 20 °F higher than the ESP inlet due to piping heat losses from the air heater to the ESP.

All tests described here were operated near 14,500 lb/h at the air heater inlet and 3,900 lb/h at the ESP inlet. The maximum flue gas flow rateat the air heater inlet was 16,500 lb/h (3640 scfm), equivalent to the flue gas from 1.7 MWe of capacity. During the entire test program no restrictions were placed on the operation of the host station. A detailed description of the pilot plant equipment and pilot plant operations is included in Appendix B.

Task 1 - Design, Fabrication, and Installation of Pilot Plant

This Task included the design, equipment and material procurement, and installation of the pilot-scale air heater and ESP system consisting of isolation valves, magnesium hydroxide sorbent feed system, water spray humidification system, corrosion probe, three fans, duct-work, monitoring instrumentation and PLC based control equipment. Additional pilot plant components included foundations, structural steel, electric power distribution and a lab/control room trailer. The design effort included preparation of process flow sheets,

piping and instrumentation diagrams, general arrangement and piping drawings, equipment specifications, control system programming, cost estimates, construction specifications, and construction supervision. Additional funding and a time extension was required due to the instability of the soil under the foundation of the air heater tower.

Task 2 - Pilot Plant Start Up and Testing Program Maintenance

Personnel were trained in the operation and evaluation of the pilot facility. All electrical and mechanical equipment components were tested, and operating problems were identified and corrected. Monitoring instrumentation was tested and calibrated as needed (sorbent feed, flue gas flows, flue gas temperature indicators, etc.). The operating and safety manual was written and distributed to pertinent personnel. Day-to-day maintenance was performed as required during each test program task.

Task 3 - Baseline Testing

Baseline operating characteristics of the pilot system were determined, focusing primarily on the air heater and ESP. Sampling included ESP inlet and outlet particulate measurements, particle size distributions, gas phase SO_3, and Hg. Additional testing was conducted to evaluate conditions around the air heater. Data obtained during this task was used as the baseline for subsequent comparisons. The air heater flue gas exit temperature was maintained at the same temperature as that of the host plant (280-320 °F). Samples of coal (mill feeders), pilot ESP ash (Location I), and Mitchell station ash (Location J) were collected during the test runs.

The velocity and temperature profiles were determined using EPA Method 2. SO_3 measurements (Locations A, B, D, F, G) were obtained using a controlled condensation method developed by CONSOL. Hg speciation and particulate (Locations A, B, F, G) were determined using the Ontario Hydro mercury speciation sampling method. Particle sizes at the ESP inlet (Location F) were determined using a 5-stage cyclone sampler and at the ESP outlet (Location G) using an Andersen 7-stage impactor.

Baseline testing was started on August 28, 2003, and completed on January 29, 2004. Gas sampling data collected during this Task is listed in Appendix A. A description of the pilot plant equipment used and activities completed during this Task is included in Appendix B.

During baseline testing, the air heater soot blowing was done every 8-12 hours. Upon completion of the baseline testing and preceding the start of $Mg(OH)_2$ injection (Task 4), one cold-end basket and one hot-end basket were removed from the air heater for inspection and replaced with two new baskets.

Task 4 - Sorbent Evaluation - SO_3 Control

The objective of this task was to optimize the alkaline sorbent dose for SO_3 capture to reduce SO_3 concentration to less than 3 ppmv during a series of short-term test runs (8 hours). A decrease in the flue gas SO_3 concentration allows for lower operating temperatures without the threat of fouling and corrosion. A reduction of the flue gas concentration to 3 ppm SO_3 was targeted because this concentration would reduce the acid dew point below 245 °F. A 5-6% solids dilute slurry of $Mg(OH)_2$ was injected into the flue gas ahead of the air heater. As the SO_3 concentration decreases, it is possible that

ESP performance will drop due to changes in the fly ash resistivity, therefore, ESP particulate removal performance was monitored throughout this task. These tests were conducted while maintaining the air heater exit temperature at the intermediate level of 250 °F.

The velocity and temperature profiles were determined at the air heater using EPA Method 2. Sulfur trioxide sampling was conducted at the air heater (Locations A, H, B, D) using a controlled condensation method developed by CONSOL. ESP performance was evaluated during this task by performing mercury removal and particulate sampling at the ESP. Mercury removal and particulate (Location f, G) were determined using the Ontario Hydro mercury speciation sampling method. Particle sizes at the ESP inlet (Location F) were determined using a 5-stage cyclone sampler and at the ESP outlet (Location G) using an Andersen 7-stage impactor.

The flue gas SO_3 concentration at the economizer outlet was 20-30 ppm, based on information from plant personnel. Thus, 80-90% SO_3 reduction was required in order to achieve the target level of 3 ppm SO_3. It was anticipated that an 80-90% SO_3 reduction would be obtained using a stoichiometric injection ratio of 2:1 to 5:1 (referenced to as moles of magnesium to each mole of SO_3). The initial alkaline injection rate tested was a ratio of 2:1. The dose rate was raised to 4:1 which reduced SO_3 concentration to less than 3 ppmv. The 5-6% solids dilute slurry of $Mg(OH)_2$ was injected with a compressed air atomizing nozzle located downstream of Location A. The slurry was diluted to 5-6% solids from 17% solids as delivered to meet the volumetric flow requirements of the atomizing nozzle.

Sorbent Evaluation testing to control sulfur trioxide at the air heater by injecting $Mg(OH)_2$ reagent was started on February 24, 2004, and completed on March 3, 2004. Gas sampling data collected during this task is listed in Appendix A. A description of the pilot plant equipment used and activities completed during this task is included in Appendix B.

Task 5 - Parametric Testing - Hg Removal

The objective of this task is to measure the Hg removal at the ESP at low (230 ºF) operating temperatures during a series of short-term test runs (8 hours). In this task the flue gas temperature was controlled by the air heater. All testing was conducted while adding an SO_3 sorbent at the dose rate of 4:1 established in Task 4. Flue gas measurements across the ESP (Location F, G) included speciated and particulate Hg. Mercury adsorbed on pilot and station ESP fly ash and coal properties were also measured.

Parametric testing to increase Hg capture by reducing the flue gas operating temperature at the air heater outlet to 235 °F while $Mg(OH)_2$ reagent was injected at a rate of approximately 4:1 molar $Mg:SO_3$ was started on March 24 and completed on March 25, 2004. Gas sampling data collected during this task is listed in Appendix A. A description of the pilot plant equipment used and activities completed during this task is included in Appendix B.

Task 6 - Flue Gas Humidification Testing – Hg Removal

The objective of this Task was to evaluate the effect of humidification on Hg removal and ESP operation during a series of short-term test runs (8 hours). In this task flue gas temperature was controlled through water spray humidification. All testing was conducted while adding an SO_3 control sorbent at the dose of 4:1 and maintaining the air heater flue gas exit temperature at 300-320 °F. The temperature downstream of humidification was controlled to 250 °F. Flue gas measurements across the ESP (Locations E, F, G) included speciated Hg, particulate, and Hg adsorbed on pilot ESP fly ash. Hg adsorbed on station ESP fly ash and station coal properties were measured.

Humidification tests to increase mercury capture by water-spray cooling to reduce the flue gas temperature at the ESP inlet to 250 °F were started on April 1 and completed on April 13, 2004. The tests were conducted at 250 °F to avoid high-voltage insulation failure in the pilot ESP. Gas sampling data collected during this task is listed in Appendix A. A description of the pilot plant equipment used and activities completed during this task is included in Appendix B.

During Tasks 4 thru 6, the air heater was soot blowed every 8-12 hours. Upon completion of Task 6 and during the week of August 9, 2004, one each of a cold-end and a hot-end basket from the pilot air heater were removed for inspection by Alstom. Replacement baskets were installed.

Task 7 - Long-Term Testing – SO_3 and Hg Removal

The primary objective was to demonstrate the long-term testing of passive Hg collection on the native fly ash through operation at reduced flue gas temperatures based on results from the previous short-term testing. Flue gas measurements for particulate and Hg concentrations were made at the inlet and outlet (Locations F, G) of the ESP, and SO_3 reduction was measured (Locations A, H) at the air heater flue gas inlet at the beginning and end of the long term testing period. A short-term test using spray cooling via flue gas humidification to lower the flue gas temperature at the ESP inlet was conducted. Data from long-term testing was used to evaluate the commercial utility of this technology. Additional fly ash samples from the pilot ESP and coal and fly ash from the station were collected and analyzed for Hg and carbon.

Preparations for long-term testing were started on April 16. Actual long-term testing began on August 21, 2004, and was completed on January 5, 2005. For all tests the gas was cooled to 200-210 °F at the pilot ESP inlet via the pilot air heater alone or the combination of air heater cooling to 270 °F and water spray cooling to 210 °F. Magnesium hydroxide was injected at a molar ratio of approximately 4:1 with the anticipated sulfur trioxide. The pilot plant was operated up to 75 hours continuously with air heater cooling and up to 4 hours with water spray cooling at long-term conditions. The water spray cooling operation was shortened due to failure of the high-voltage insulation in the pilot ESP. Sampling data collected during this task is listed in Appendix A. A description of the pilot plant equipment used and activities completed during this task is included in Appendix B.

During long-term tests in August and September 2004, the air heater was soot blowed every 8-12 hours. During long-term tests in December 2004, the air heater was operated continuously for 74 and 75 hours without soot blowing. On January 5, 2005, one each of a cold-end basket and a hot-end basket from the pilot air heater were removed for inspection by Alstom.

Task 8 - Corrosion Study

The objective of this Task was to evaluate the corrosive effect of low-temperature flue gas operation on pilot plant components (duct work, air heater, ESP). CONSOL utilized a number of techniques to evaluate the corrosion potential including in-duct corrosion coupons located downstream of the ESP (Location G), a temperature-controlled corrosion probe located upstream of the ESP (Location F) and examination of air heater baskets three different times during Tasks 3-7.

The in-duct coupons consisted of A36, Cortan A and Cortan B carbon steels, at the pilot ESP outlet (Location G) were exposed to flue gas from Task 3 through Task 7. The temperature-controlled (150 °F) corrosion probe at the pilot ESP inlet (Location F) consisted of single A36 carbon steel coupon exposed to flue gas during Task 3 and then a single A36 carbon steel coupon exposed to flue gas during Tasks 4-7. The corrosion coupons were removed for analysis in January 2005. The corrosion coupon examination procedure included photographing, weighing, and measuring the thickness of the coupons, and lab analysis of deposits.

Task 9 - Stability of Hg on Fly Ash

The objective of this Task was to evaluate the stability of the adsorbed Hg on the ESP ash. Samples of pilot ESP ash were taken during the baseline test, short-term test program (with and without humidification), and a sample of the station ESP ash was also collected. Mercury was determined on the four samples, and the four samples were subjected to both TCLP leaching and volatilization studies. The leaching tests included three pHs (3, 5, and 7), and mercury was determined in the leachates and the unextracted solids resulting from the leaching tests. The volatility tests were conducted at 140 °F; samples were taken after 2-1/2 and 4-1/3 months and mercury was determined on the samples.

The leaching tests were conducted by EPA method 1311 and ASTM Method D3987. The samples were leached with three different leachate solutions: 1) acetic acid buffered to a pH of 2.8, 2) acetic acid at a pH of 4.9, and 3) deionized water. The acetic acid buffered solutions are specified by the Toxicity Characterization Leaching Procedure – U.S. EPA Method 1311. The deionized water extraction is specified by the ASTM leaching procedure D3987. Except for the pH of the extraction media used, the two methods are identical. QA/QC procedures included performing duplicate sample analyses.

Volatilization tests were performed using a methodology developed by CONSOL. The samples were first analyzed for concentration of mercury, carbon, moisture, and ash, when they were received. Fifty grams of each fly ash sample was then placed in each of two 250 mL (8 oz) glass bottles. The two bottles of fly ash were held for 4-1/3 months in an oven at a temperature of 140 °F. Each bottle was equipped with a

continuous Hg-free air purge, to prevent atmospheric Hg contamination of the samples. Five-gram fly ash samples from each bottle were removed and analyzed at 2-1/2 and 4-1/3 months using ASTM Method D 6722, “Total Mercury in Coal and Coal Combustion Residues by Direct Combustion Analysis”. The oven was held at temperature of 140 °F to represent a typical range that the samples might incur at an actual landfill site.

Task 11 - Report on ESP Operation and Performance

The objective of this Task was to evaluate precipitator performance at the various operating conditions. Environmental Elements performed an initial check-out of the system and then monitoring of power consumption, electrical performance, and secondary voltage and current data. A report specific to the ESP operation at the various operating conditions is included in Appendix C.

Task 12 - Report on Air Heater Operation and Performance

The objective of this Task was to evaluate air heater performance at the various operating conditions. This Task was performed by Alstom. Alstom performed an initial check-out of the system, and conducted periodic performance audits. Alstom prepared a detailed report specific to air heater operation at the various operating conditions (Appendix D).

RESULTS AND DISCUSSION

A schematic of the pilot plant is shown in Figure 2. Please refer to this schematic for sampling Locations and equipment referred to in the following text.

Sulfur Trioxide Sampling and Control

A diluted $Mg(OH)_2$ slurry was injected into the flue gas slipstream upstream of the air heater to control sulfur trioxide (SO_3) concentration to prevent acid condensation whenever the air heater was operated at reduced flue gas temperatures (250 °F or less). Injection was performed with an air/slurry nozzle mounted in the 20" diameter duct. Flue gas temperatures at the air heater inlet varied from 531-636 °F during the test periods described here. All SO_3 sampling was performed using the controlled condensation sampling method. Each sampling run was conducted simultaneously at each test location for a period of 40 minutes. Sampling was performed during baseline testing (Task 3), sorbent evaluation (Task 4) and long-term testing (Task 7).

Table 1 shows average SO_3 concentrations (and the calculated acid dew points) at various Locations in the pilot plant during test periods with no injection of magnesium hydroxide and during periods in which the magnesium hydroxide was injected at Mg/SO_3 molar ratios of 1.9:1, 4:1 and higher. The SO_3 concentration at Location A (inlet) during the period with no magnesium hydroxide injection (baseline testing) is lower than that at the same location during the periods with magnesium hydroxide injection as a result of host plant operations. No limitations were placed on the host plant operations during any of the sampling runs. The higher SO_3 concentrations appear to be more typical. The targeted SO_3 concentration of 3 ppmv or less at the air heater flue gas inlet (Location H) was achieved with a 4:1 Mg/SO_3 molar ratio. Therefore, all later testing was conducted with magnesium hydroxide injection at an Mg/SO_3 molar ratio at or near 4:1 based on 30 ppmv SO_3 concentration and 14,000 lb/hr flue gas. On some occasions the host plant provided flue gas with lower than expected concentration of SO_3. The Mg/SO_3 molar ratio was substantially higher than 4:1 during those periods, because the Mg injection rate was based on an assumed normal concentration of 30 ppmv. A complete summary of the sulfur trioxide sampling data gathered during Tasks 3, 4 and 7 is shown in Table 2.

Table 1. Effectiveness of $Mg(OH)_2$ Injection for SO_3 Control

	Average SO_3 Concentration, ppmv (Acid Dew Point, °F)		
Mg:SO_3 Mole Ratio Test Period	Before Mg Injection at Location A	After Mg Injection / % Removal Air Heater Gas Inlet at Location H	Air Heater Gas Out at Location B
None Task 3- Baseline	12.5 (274)	Not Determined	2.1 (237)
1.9/1 Task 4- Sorbent Evaluation	31.4 (278)	6.8 (256) / 79%	1.2 (230)
4.0/1 Task 4- Sorbent Evaluation	32.5 (288)	1.8 (236) / 94%	0.7 (222)
4.0 to 27/1* Task 7- Long-Term	14.8 (276)	2.2 (239) / 84 %	Not Determined

*Excursions to high ratios caused by unexpected low SO_3 concentrations, cf text.

As shown in Table 2, the most dramatic change in SO_3 concentration occurred at the air heater hot air outlet (Location D) where SO_3 concentrations were reduced from a high of 53 to 4.4 ppmv. During baseline tests (no Mg injection) and at lower $Mg(OH)_2$ injection ratios (1.9/1), a substantial amount of SO_3 was recycled through the air heater from the flue gas side to the air side. As the $Mg(OH)_2$ injection ratio was increased to 4/1, the concentration at the air heater hot air outlet (Location D) decreased as shown in Figure 3. Devito and Oda [1998] reported that, in one full-scale boiler, approximately 40% of the SO_3 present at the air heater flue gas inlet is removed by the air heater. This removal is due to a condensation-volatilization mechanism consistent with the rotation of the air heater elements. The SO_3 reduction at the air outlet (Location D) shown in Figure 3 appears to be directly related to the SO_3 reduction at the air heater flue gas inlet (Location H).

Table 2. Sulfur Trioxide Sampling Results

						Location A (Gas side AH In - before slurry injection)			Location H (Gas side AH In - after slurry injection)				Location B (Gas side AH Out)			Location D (Air side AH Out)			Location F (ESP In)		
Run #	Date	Time Start	Time Stop	%Coal Sulfur	Molar Ratio $Mg(OH)_2 : SO_3$	SO_3 PPMv	Gas ^oF	SO3 DP ^oF	SO3 PPMv	Gas ^oF	SO3 DP ^oF	% A - H Reduction	SO3 PPMv	Gas ^oF	SO3 DP ^oF	SO3 PPMv	Gas ^oF	SO3 DP ^oF	SO3 PPMv	Gas ^oF	SO3 DP ^oF
		Task 3 Baseline																			
3-1	12/19/03	14:07	14:47	3.22	0	15.6	633	278											5.9	293	253
3-2	12/19/03	16:10	16:50	3.22	0	17.4	629	280											2.0	291	236
3-3	1/20/04	14:00	14:40	2.78	0	14.2	619	276					0.9	339	226	46.8	542	219			
3-4	1/21/04	10:22	11:02	2.76	0	11.8	612	273					3.3	314	245	53.2	540	222			
3-5	1/21/04	12:45	13:25	2.76	0	11.5	613	273					2.3	316	239	44.6	543	218			
3-6	1/21/04	14:20	15:00	2.76	0								2.0	315	237						
		Task 4 Sorbent Evaluation																			
4-1	3/2/04	13:09	14:09	3.13	1.7	33.3	610	288	10.2	579	265	69	1.0	252	227	25.8	485	214			
4-2	3/2/04	15:45	16:45	3.36	1.7	29.5	613	286	3.3	581	247	89	1.5	254	232	31.3	487	217			
4-3	3/3/04	11:00	12:00	2.99	4.05	34.3	613	289	2.1	588	239	94	0.8	254	224	8.5	491	192			
4-4	3/3/04	14:35	15:35	3.11	4.05	30.7	594	287	1.4	558	234	95	0.6	254	220	4.4	475	192			
		Task 7 Long Term																			
7-1	9/8/04	12:01	12:41	3.22	26.83	4.2	636	253	0.6	582	227	86									
7-2	9/9/04	10:00	11:00	3.24	4.45	22.3	538	279	1.0	499	228	96									
7-3	9/9/04	12:05	13:05	2.97	4.45	26.5	531	282	5.6	486	251	79									
7-4	12/15/04	10:30	11:30	3.34	20.98	4.6	618	255	0.7	577	218	85									
7-5	12/15/04	13:35	14:35	3.18	11.31	8.3	619	265	1.1	578	231	87									
	12/16/04	9:45	10:45	3.59	~4	Probe Failed			3.6	522	247										
7-6	12/16/04	12:20	13:20	3.38	4.02	22.7	561	281	3.0	520	244	87									
7-7	12/16/04	15:20	16:20	3.38	3.42	27.1	541	283	6.8	508	257	75									
AVE	Average during Mg(OH)2 Injection					22.1		277	3.3		241	86			226						

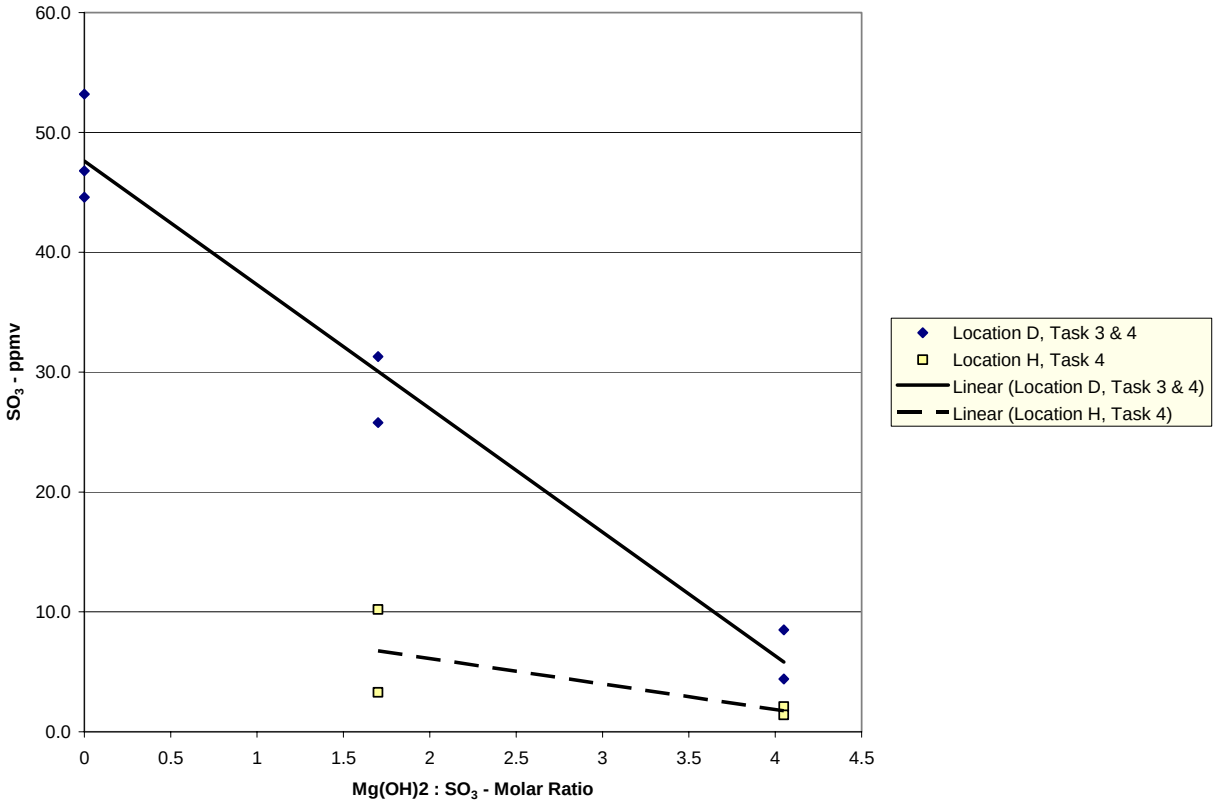


Figure 3. SO_3 Measured at Air Outlet (Location D) and Flue Gas Inlet (Location H) of Air Heater

As shown in Table 2, substantial variations in SO_3 concentrations (4.6-33.3 ppmv) and temperature (531-636 ^{O}F) at the air heater flue gas inlet (Location A) occurred due to changes in boiler operation. The load on the boiler was not held constant during the test runs. The temperature at the air heater inlet (Location A) varied according to the load; the maximum temperature corresponding to full load. Figure 4 charts the variation of SO_3 concentrations at Location A and H and percent reduction. During run # 7-7, the molar ratio was reduced to 3.4 from the targeted ratio of 4.0 to determine sensitivity. As a result, the SO_3 concentration at the air heater flue gas inlet (Location H) rose to 6.8 and the reduction in SO_3 concentration dropped to 75%. All other test runs were at ratios of 4 and higher with the exception of the first two runs which were at a ratio of 1.7. As shown in Table 2 gas sampling was only done at Locations A and H during long-term testing since earlier sampling at Location B was well below 3 ppmv.

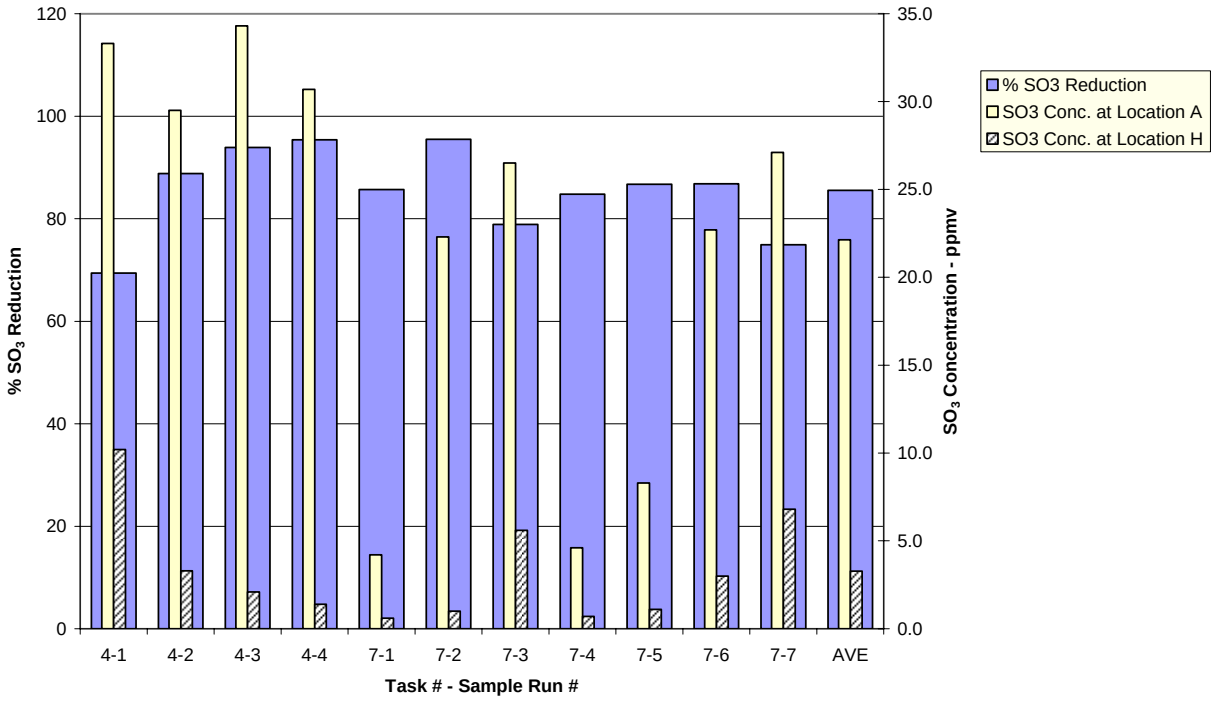


Figure 4. SO_3 Reduction and Concentrations at Locations A and H at Molar Ratios: 1.7 (4-1 and 4-2), 4 to 27 (4-3 through 7-6), 3.4 (7-7)

Mercury Sampling and Control

Mercury sampling and control at the pilot electrostatic precipitator (ESP) was done at three different flue gas temperature conditions at the ESP inlet:

1. **290 °F at ESP inlet**: Long-term baseline (Task 3) testing with no magnesium hydroxide injection and air heater flue gas exit temperatures of 300-315 °F.
2. **230-250 °F at ESP inlet**: Short-term (<8 hours) sorbent evaluation (Task 4), parametric (Task 5) and humidification (Task 6) testing with injection of magnesium hydroxide sorbent at a molar ratio of 2/1 to 4/1, and air heater flue gas exit temperatures of 235-250 °F during sorbent evaluation and parametric testing, and 315 °F during humidification testing.
3. **200-210 °F at ESP inlet:** Long-term (Task 7) testing (>55 hours) at deep cooling of the flue gas via the air heater or water spray humidification with injection of magnesium hydroxide at a molar ratio of approximately 4:1, and air heater flue gas exit temperature of about 230 °F during air heater only cooling, and 270 °F during combination air heater and water spray humidification.

During test conditions 1 and 2 (Tasks 3-6) the host plant generated at nearly full load ca. 288 MW for all runs. During test condition 3 (Task 7) the host plant operated from

the lowest load (~100 MW) to the highest load (288 MW) for the sampling runs. The flue gas temperature dropped 10 to 20 °F from Location B (air heater outlet) to location F (ESP inlet) depending on ambient temperature conditions. The distance from Location B to F is about 150 feet.

A diluted $Mg(OH)_2$ slurry was injected into the flue gas slipstream upstream of the air heater whenever flue gas temperatures were lowered for test conditions 2 and 3. Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02). All sample runs were 120 minutes in duration, with sampling occurring simultaneously at each test Location. A minimum of three sampling runs were done at each test condition. The average mercury removals at the ESP are shown in Table 3.

Table 3. Mercury Removal at ESP

Test Condition	Temp., °F ESP Inlet (Location F)	Hg Removal By ESP, Gas Inlet to Outlet Average %	"Carbon Treat Rate" Average lbs Carbon /million scf and acf (Range of Data)	
Baseline (Task 3)	290	26	41 scf	26 acf
Short-Term (Tasks 4,5,6)	230-250	49	35 (23-46) scf	23 (15-31) acf
Long-Term (Task 7)	200-210	81	47(23-71) scf	33 (15-51) acf

As shown in Table 3, mercury capture at baseline conditions is about 26%. As the ESP inlet temperature is lowered with the air heater and/or humidification to 200-210 °F (and with magnesium hydroxide injection), the mercury capture increased to an average of 81%. The unburned carbon in the fly ash and the gas flow rate were used to calculate the "carbon treat rate", in a manner similar to that reported for mercury capture tests with powdered activated carbon injection. In this case, however, the carbon is simply the unburned carbon on the fly ash that is native to the flue gas. The "carbon treat rate" is also shown in Table 3. Some of the higher mercury removals obtained at ESP inlet temperatures of 200-210 °F (condition 3), result from the higher "carbon treat rate" during that period, as discussed later.

Tables 4 and 5 include a description of test conditions, data collected, and results from Ontario Hydro Mercury Sampling. Please refer to the process schematic shown in Figure 2 for sampling Locations and equipment referred to in Tables 4 and 5. Appendix A contains the data from the Ontario Hydro gas sampling used to prepare Tables 4 and 5.

Table 4. Ontario Hydro Mercury Sampling Results and Test Conditions

						Location A (Gas side AH in - before slurry injection)			Location B (Gas side AH out)			Location E (AH Outlet)				Location F (ESP In)						Location G (ESP Out)		
OH Run	Date	Time		Coal		Total ug/m3	Gas °F	Flyash % C	Total ug/m3	Gas °F	Flyash % C	Total ug/m3	Gas °F	Flyash % C	Gas dscfm	Total ug/m3	Gas °F	Flyash % C	Gas dscfm	Part. Lb/hr	Part. gr/dscf	Total ug/m3	Gas °F	Gas dscfm
		Start	Stop	Hg PPM	Cl dry %																			
		Task 3 Baseline																						
3-1	12/17/03	12:30	14:48	0.110	0.055	13.45	596						300			8.46	279		770	19.9	2.90	6.96	279	850
3-2	1/29/04	10:00	12:10	0.130	0.071	12.8	616	6.64	11.71	303	5.96		295			9.60	291	6.28	860	24.7	3.20	8.02	275	890
3-3	1/29/04	15:00	17:00	0.120	0.073	12.4	607	6.79	11.71	303	6.65		293			11.60	289	7.00	870	30.1	3.90	7.00	275	880
		Task 4 Sorbent Evaluation																						
4-1	2/24/04	12:25	14:40	0.110	0.09		620			250			240			14.74	235	7.15	855	28.33	3.67	8.56	247	994
4-2	2/27/04	11:30	13:35	0.110	0.08		616			250			240			11.67	238	7.69	850	19.28	2.81	8.05	247	974
4-3	3/1/04	12:05	14:05	0.120	0.07		620			250			243			15.18	239	7.08	847	25.24	3.68	10.66	251	972
		Task 5 Parametric Testing																						
5-1	3/24/04	13:10	15:25	0.110	0.06		637			235			230			15.14	230	5.20	829	18.86	2.75	8.76	210	871
5-2	3/25/04	10:32	12:45	0.110	0.07		638			235			230			15.01	233	5.90	831	17.79	2.59	10.90	215	878
5-3	3/25/04	14:29	17:00	0.110	0.06		620			235			230			14.83	234	5.64	810	18.18	2.74	2.70	219	847
		Task 6 Humidification Testing																						
6-1	4/1/04	15:15	17:36	0.090	0.05		613.0			315		13.1	287	5.64	705	12.45	249	5.28	788	11.26	2.68	11.25	219	832
6-2	4/13/04	10:55	13:15	0.110	0.05		629.0			315		14.8	293	10.36	743	11.64	249	9.44	750	14.93	2.18	5.86	220	876
6-3	4/13/04	15:15	17:28	0.110	0.06		632.0			315		11.0	292	8.28	740	12.41	250	8.98	751	16.24	2.37	6.14	220	889
		Task 7 Long Term																						
7-1	9/8/04	11:25	14:23	0.109	0.09		629			230			225			10.66	198	16.05	913	26.48	3.43	0.35	217	1050
7-2	9/9/04	9:30	11:38	0.141	0.08		537			230			227			14.91	203	5.36	885	27.59	3.57	3.69	222	950 est
7-3	9/9/04	12:51	15:13	0.120	0.07		527			230			229			13.43	210	5.48	879	20.69	2.68	2.99	223	946
7-4	12/15/04	9:40	11:45	0.101	0.06		625			230			216			11.88	201	10.75	950	37.83	4.41	0.60	200	1133
7-5	12/15/04	13:50	15:57	0.119	0.06		618			230			215			14.84	198	10.71	933	36.67	4.75	0.53	201	1148
7-6	12/16/04	9:24	11:27	0.121	0.06		571			230			217			14.01	205	6.38	936	29.4	3.81	2.54	203	1132
7-7	12/16/04	13:45	15:49	0.096	0.06		557			270			255			11.19	208	5.22	956	25.76	3.00	3.58	206	1161
7-8	12/17/04	11:13	13:16	0.100	0.05		603			270			255			14.6	209	5.82	889	29.97	3.88	2.82	207	1120
							Temperatures measured during sampling are averaged.																	
							All other temperatures are from single point sensors. The average temperature may be 5-10 degrees lower.																	

Table 4. Ontario Hydro Mercury Sampling Results and Test Conditions (cont'd)

						Location I		Location F (ESP In)								
OH		Time		Coal		(P. ESP Flyash)		Carbon Rate		% Removal	% Removal	% Hg	Gas	ESP % Ash	S. ESP Flyash	
Run	Date	Start	Stop	Hg PPM	Cl dry %	Hg PPM	% C	lb/mmdscf	lb/mmacf	Hg F to G	Hg F to I	Balance	Cooling	Removal	Hg PPM	C dry %
		Task 3 Baseline														
3-1	12/17/03	12:30	14:48	0.110	0.055	0.730	18.95	81.8	52.6	9	59	150		99.7	0.340	8.24
3-2	1/29/04	10:00	12:10	0.130	0.071	0.320	7.15	34.3	21.6	13	25	112		99.4	0.310	7.54
3-3	1/29/04	15:00	17:00	0.120	0.073	0.310	7.15	41.3	26.0	39	25	86		99.7	0.310	7.54
		Task 4 Sorbent Evaluation														
4-1	2/24/04	12:25	14:40	0.110	0.09	0.670	8.42	46.5	31.3	40	51	110	AH	99.4	0.27	7.01
4-2	2/27/04	11:30	13:35	0.110	0.08	0.780	9.61	36.3	24.3	31	48	117	AH	99.8	0.20	5.59
4-3	3/1/04	12:05	14:05	0.120	0.07	0.670	7.86	39.0	26.1	29	43	114	AH	99.6	0.21	5.01
		Task 5 Parametric Testing														
5-1	3/24/04	13:10	15:25	0.110	0.06	0.620	5.95	22.6	15.3	48	32	84	AH	98.9	0.30	8.65
5-2	3/25/04	10:32	12:45	0.110	0.07	0.850	8.39	29.9	20.1	35	38	102	AH	93.8	0.27	9.48
5-3	3/25/04	14:29	17:00	0.110	0.06	0.800	8.59	32.1	21.5	83	39	56	AH	95.6	0.23	8.89
		Task 6 Humidification Testing														
6-1	4/1/04	15:15	17:36	0.090	0.05	Sampler Failed				17			WS	98.9	0.10	10.81
6-2	4/13/04	10:55	13:15	0.110	0.05	0.870	11.02	36.6	23.0	48	49	101	WS	99.5	0.21	11.41
6-3	4/13/04	15:15	17:28	0.110	0.06	0.860	9.83	35.4	22.1	50	48	98	WS	99.6	0.23	12.72
		Task 7 Long Term														
7-1	9/8/04	11:25	14:23	0.109	0.09	0.810	14.65	70.8	48.1	96	59	62	AH	99.8	0.470	15.14
7-2	9/9/04	9:30	11:38	0.141	0.08	1.090	7.22	37.5	26.0	73	61	87	AH	99.5	0.900	18.08
7-3	9/9/04	12:51	15:13	0.120	0.07	0.990	5.53	21.7	14.9	76	46	70	AH	99.5	1.110	18.17
7-4	12/15/04	9:40	11:45	0.101	0.06	0.742	10.62	70.5	50.6	94	66	72	AH	99.2	0.808	21.38
7-5	12/15/04	13:50	15:57	0.119	0.06	0.770	10.70	70.1	50.3	96	54	59	AH	99.3	0.735	22.11
7-6	12/16/04	9:24	11:27	0.121	0.06	0.799	7.34	38.4	27.5	78	48	70	AH	99.3	0.799	17.09
7-7	12/16/04	13:45	15:49	0.096	0.06	0.734	5.82	26.1	18.2	61	47	86	AH/WS	99.1	1.070	12.18
7-8	12/17/04	11:13	13:16	0.100	0.05	0.746	7.21	40.5	28.2	76	44	69	AH/WS	97	0.648	10.82

Table 5. Ontario Hydro Mercury Speciation Results and Test Conditions

						Location A (Gas side AH in - before slurry injection)						Location B (Gas side AH out)						Location E (AH Outlet)						Location F (ESP In)						Location G (ESP Out)					
OH		Time		Coal		Gas	Gas	Total	Part.	Oxid.	Elem.	Gas	Gas	Total	Part.	Oxid.	Elem.	Gas	Gas	Total	Part.	Oxid.	Elem.	Gas	Gas	Total	Part.	Oxid.	Elem.	Gas	Gas	Total	Part.	Oxid.	Elem.
Run	Date	Start	Stop	Hg PPM	Cl dry %	°F	dscfm	ug/m3	ug/m3	ug/m3	ug/m3	°F	dscfm	ug/m3	ug/m3	ug/m3	ug/m3	°F	dscfm	ug/m3	ug/m3	ug/m3	ug/m3	°F	dscfm	ug/m3	ug/m3	ug/m3	ug/m3	°F	dscfm	ug/m3	ug/m3	ug/m3	ug/m3
	Task 3 Baseline																																		
3-1	######	12:30	14:48	0.110	0.055	596	3004	15.37	1.20	5.97	8.20													279	770	10.46	6.20	3.22	1.04	279	850	9.83	0.015	7.83	1.99
3-2	1/29/04	10:00	12:10	0.130	0.071	616	2807	15.38	0.61	6.59	8.18	303	1861	14.67	4.59	8.88	1.20							291	860	12.49	3.52	7.21	1.75	275	890	11.81	0.003	9.35	2.45
3-3	1/29/04	15:00	17:00	0.120	0.073	607	2907	14.83	0.82	5.60	8.41	303	2717	14.65	4.60	8.99	1.06							289	870	14.97	6.80	6.87	1.30	275	880	10.00	0.006	7.89	2.1
	Task 4 Sorbent Evaluation																																		
4-1	2/24/04	12:25	14:40	0.110	0.09	620																		235	855	14.74	13.20	0.98	0.57	247	994	8.56	0.033	6.74	1.78
4-2	2/27/04	11:30	13:35	0.110	0.08	616																		238	850	11.67	10.96	0.72	0.00	247	974	8.05	0.009	5.92	2.12
4-3	3/1/04	12:05	14:05	0.120	0.07	620																		239	847	15.18	13.93	1.25	0.00	251	972	10.66	0.010	7.89	2.76
	Task 5 Parametric Testing																																		
5-1	3/24/04	13:10	15:25	0.110	0.06	637																		230	829	15.14	12.29	2.31	0.55	210	871	8.76	0.079	5.91	2.78
5-2	3/25/04	10:32	12:45	0.110	0.07	638																		233	831	15.01	12.87	1.63	0.51	215	878	10.90	0.115	8.57	2.21
5-3	3/25/04	14:29	17:00	0.110	0.06	620																		234	810	14.83	13.55	0.75	0.53	219	847	2.70	0.200	2.09	0.41
	Task 6 Humidification Testing																																		
6-1	4/1/04	15:15	17:36	0.090	0.05	613.0												287	705	13.12	2.31	9.84	0.97	249	788	12.45	7.50	3.52	1.43	219	832	11.25	0.090	7.52	3.64
6-2	4/13/04	10:55	13:15	0.110	0.05	629.0												293	743	14.77	13.67	0.59	0.51	249	750	11.64	10.39	0.70	0.54	220	876	5.86	0.020	3.80	2.04
6-3	4/13/04	15:15	17:28	0.110	0.06	632.0												292	740	11.04	9.76	0.74	0.53	250	751	12.41	11.16	0.72	0.53	220	889	6.14	0.050	3.98	2.12
	Task 7 Long Term																																		
7-1	9/8/04	11:25	14:23	0.109	0.09	629																		198	913	10.66	9.65	0.85	0.16	217	1050	0.35	0.070	0.18	0.10
7-2	9/9/04	9:30	11:38	0.141	0.08	537																		203	885	14.91	13.99	0.70	0.22	222	950 est	3.69	0.070	3.19	0.44
7-3	9/9/04	12:51	15:13	0.120	0.07	527																		210	879	13.43	12.56	0.64	0.23	223	946	2.99	0.020	2.58	0.38
7-4	######	9:40	11:45	0.101	0.06	625																		201	950	11.88	10.23	1.47	0.18	200	1133	0.62	0.024	0.49	0.11
7-5	######	13:50	15:57	0.119	0.06	618																		198	933	14.84	12.29	2.37	0.19	201	1148	0.54	0.011	0.44	0.10
7-6	######	9:24	11:27	0.121	0.06	571																		205	936	14.01	12.50	1.30	0.21	203	1132	2.55	0.018	2.05	0.48
7-7	######	13:45	15:49	0.096	0.06	557																		208	956	11.19	10.33	0.64	0.21	206	1161	3.60	0.040	2.94	0.62
7-8	######	11:13	13:16	0.100	0.05	603																		209	889	14.60	13.75	0.63	0.22	207	1120	2.82	0.040	2.21	0.57

Table 5. Ontario Hydro Mercury Speciation Results and Test Conditions (cont'd)

						Location G (ESP Out)						Location I		Carbon Rate lb/mscf					
OH Run	Date	Time		Coal		Gas °F	Gas dscfm	Total ug/m3	Part. ug/m3	Oxid. ug/m3	Elem. ug/m3	(P. ESP Flyash)			% Removal Hg F to G	% Removal Hg F to I	% Hg Balance	Gas Cooling	ESP % Ash Removal
		Start	Stop	Hg PPM	Cl dry %							Hg PPM	% C						
	Task 3 Baseline																		
3-1	12/17/03	12:30	14:48	0.110	0.055	279	850	9.83	0.015	7.83	1.99	0.730	18.95		9	59	150		99.7
3-2	1/29/04	10:00	12:10	0.130	0.071	275	890	11.81	0.003	9.35	2.45	0.320	7.15		13	25	112		99.4
3-3	1/29/04	15:00	17:00	0.120	0.073	275	880	10.00	0.006	7.89	2.1	0.310	7.54	41.30	39	25	86		99.7
	Task 4 Sorbent Evaluation																		
4-1	2/24/04	12:25	14:40	0.110	0.09	247	994	8.56	0.033	6.74	1.78	0.670	8.42	46.50	40	51	110	AH	99.4
4-2	2/27/04	11:30	13:35	0.110	0.08	247	974	8.05	0.009	5.92	2.12	0.780	9.61	36.30	31	48	117	AH	99.8
4-3	3/1/04	12:05	14:05	0.120	0.07	251	972	10.66	0.010	7.89	2.76	0.670	7.86	39.00	29	43	114	AH	99.6
	Task 5 Parametric Testing																		
5-1	3/24/04	13:10	15:25	0.110	0.06	210	871	8.76	0.079	5.91	2.78	0.620	5.95	22.60	48	32	84	AH	98.9
5-2	3/25/04	10:32	12:45	0.110	0.07	215	878	10.90	0.115	8.57	2.21	0.850	8.39	29.90	35	38	102	AH	93.8
5-3	3/25/04	14:29	17:00	0.110	0.06	219	847	2.70	0.200	2.09	0.41	0.800	8.59	32.10	83	39	56	AH	95.6
	Task 6 Humidification Testing																		
6-1	4/1/04	15:15	17:36	0.090	0.05	219	832	11.25	0.090	7.52	3.64	Sampler Failed			17			WS	98.9
6-2	4/13/04	10:55	13:15	0.110	0.05	220	876	5.86	0.020	3.80	2.04	0.870	11.02	36.60	48	49	101	WS	99.5
6-3	4/13/04	15:15	17:28	0.110	0.06	220	889	6.14	0.050	3.98	2.12	0.860	9.83	35.40	50	48	98	WS	99.6
	Task 7 Long Term																		
7-1	9/8/04	11:25	14:23	0.109	0.09	217	1050	0.35	0.070	0.18	0.10	0.810	14.65	70.80	96	59	62	AH	99.8
7-2	9/9/04	9:30	11:38	0.141	0.08	222	950 est	3.69	0.070	3.19	0.44	1.090	7.22	37.50	73	61	87	AH	99.5
7-3	9/9/04	12:51	15:13	0.120	0.07	223	946	2.99	0.020	2.58	0.38	0.990	5.53	21.70	76	46	70	AH	99.5
7-4	12/15/04	9:40	11:45	0.101	0.06	200	1133	0.62	0.024	0.49	0.11	0.742	10.62	70.50	94	66	72	AH	99.2
7-5	12/15/04	13:50	15:57	0.119	0.06	201	1148	0.54	0.011	0.44	0.10	0.770	10.70	70.10	96	54	59	AH	99.3
7-6	12/16/04	9:24	11:27	0.121	0.06	203	1132	2.55	0.018	2.05	0.48	0.799	7.34	38.40	78	48	70	AH	99.3
7-7	12/16/04	13:45	15:49	0.096	0.06	206	1161	3.60	0.040	2.94	0.62	0.734	5.82	26.10	61	47	86	AH/WS	99.1
7-8	12/17/04	11:13	13:16	0.100	0.05	207	1120	2.82	0.040	2.21	0.57	0.746	7.21	40.50	76	44	69	AH/WS	97

Mercury Material Balance Closure

Table 4 lists the mercury material balance closures based on the incoming mercury and particulate at the ESP gas inlet (Location F), and outgoing mercury at the ESP gas outlet (Location G) and on the collected fly ash from the ESP hopper (Location I). The mercury material balance closure is calculated as follows.

$$\frac{\text{Mercury flow rate out of ESP}}{\text{Mercury flow rate into the ESP}} \times 100\ \%$$

or

$$\frac{[\text{flow rate of Hg in flue gas at ESP outlet (Loc. G)}] + [\text{flow rate of Hg on fly ash collected at ESP hopper (Loc. I)}]}{[\text{flow rate of Hg in flue gas and on fly ash at ESP inlet (Loc. F)}]}$$

The actual flow rate of collected fly ash could not be measured; therefore, the collected fly ash flow rate at the ESP hopper (Location I) is determined from the fly ash flow rate measured at the ESP inlet (Location F).

Mercury material balance closures in the range of 100% +/- 20% are considered to be an indication of reliable mercury sampling data. A plot of mercury material balance closure versus ESP flue gas temperature in Figure 5 shows a steady decline as flue gas temperatures were lowered from baseline testing (Task 3) to long-term testing (Task 7) with baseline temperatures at 280 °F or higher. A plot of mercury material balance closure versus mercury removal from ESP flue gas inlet to outlet in Figure 6 shows a steady decline in closure as mercury removal increased from baseline testing (Task 3) to long-term testing (Task 7). Figure 7, a plot of mercury material balance closure versus oxidized and total mercury concentration at the ESP flue gas outlet (Location G) shows a decline in the balance as both mercury concentrations decrease at the ESP outlet. Figures 5, 6, and 7 show a clear pattern of declining mercury material balance closure as gas temperatures drop and mercury removals increase. Figure 8, mercury material balance closure versus total mercury concentration at both the ESP flue gas outlet (Location G) and the ESP inlet (Location F) shows declining Hg balance even though the total mercury entering the ESP is randomly scattered. The concentration of mercury entering the ESP is scattered between 10 and 15 ug/m^3, and does not appear to influence the mercury material balance. A plot of the mercury material balance closure versus carbon treat rate, Figure 9, shows a material balance closure decline as carbon treat rate increased during the long-term sampling runs (Task 7). Figure 6 shows declining closures as mercury removal increased and Figure 9 shows a similar decline as carbon increased during Task 7.

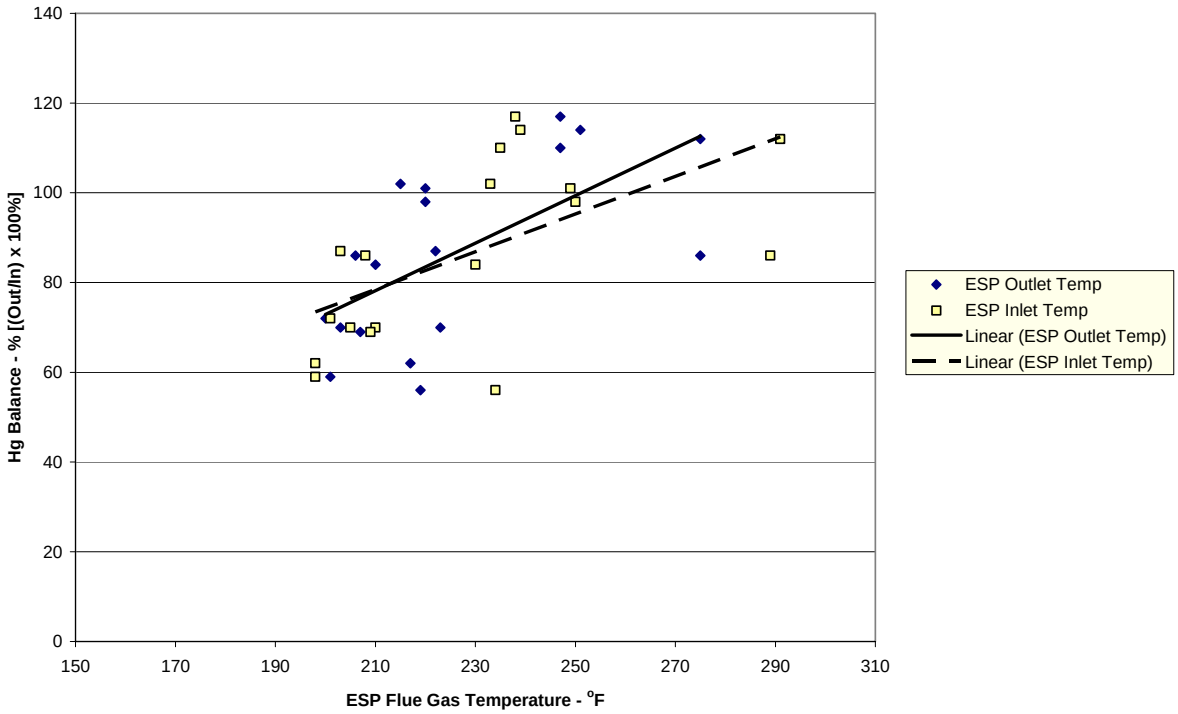


Figure 5. Mercury material balance closure versus ESP Flue Gas Temperature, Task 3-7

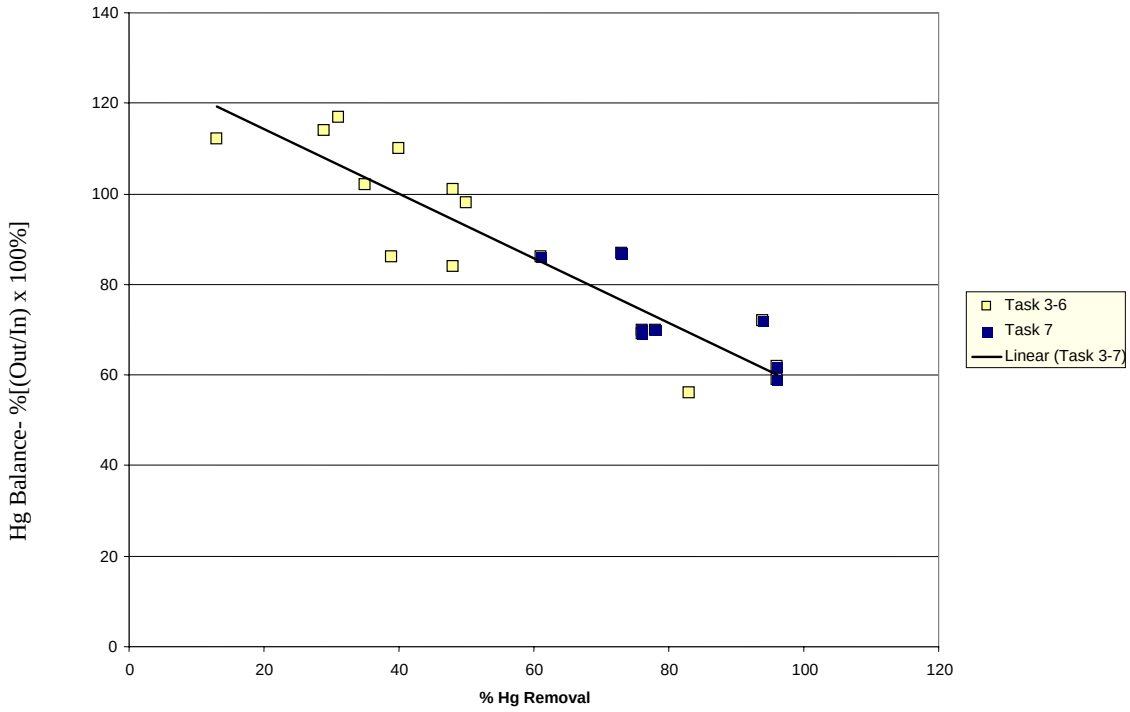


Figure 6. Mercury material balance closure versus Percent Mercury Removal (F to G)

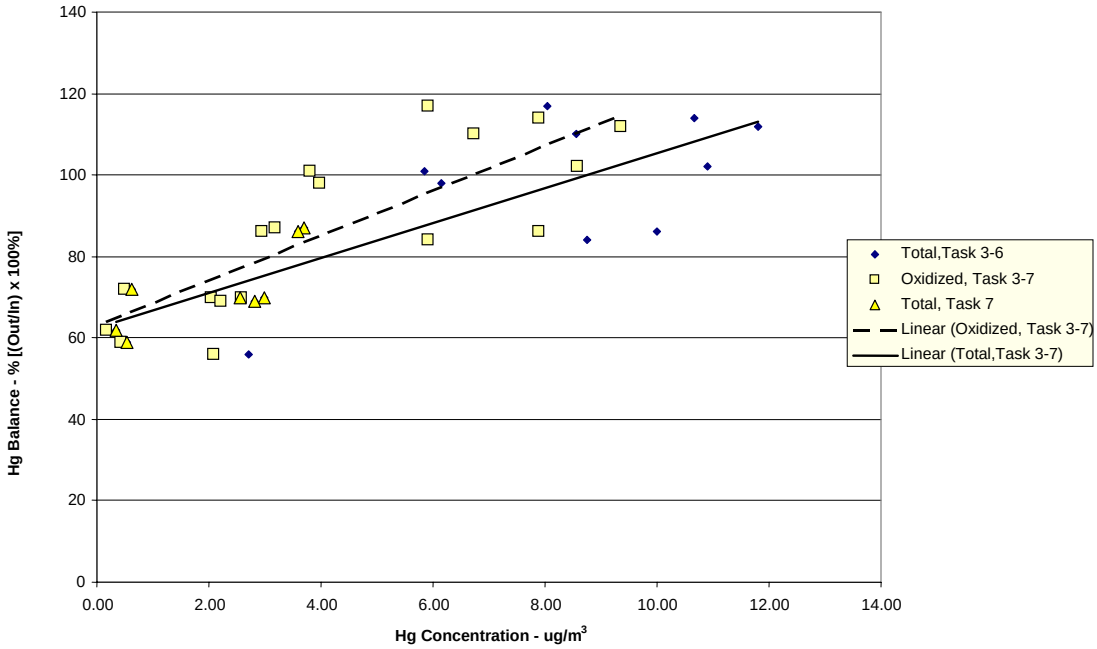


Figure 7. Mercury material balance closure versus oxidized and total mercury concentration at the ESP flue gas outlet (Location G)

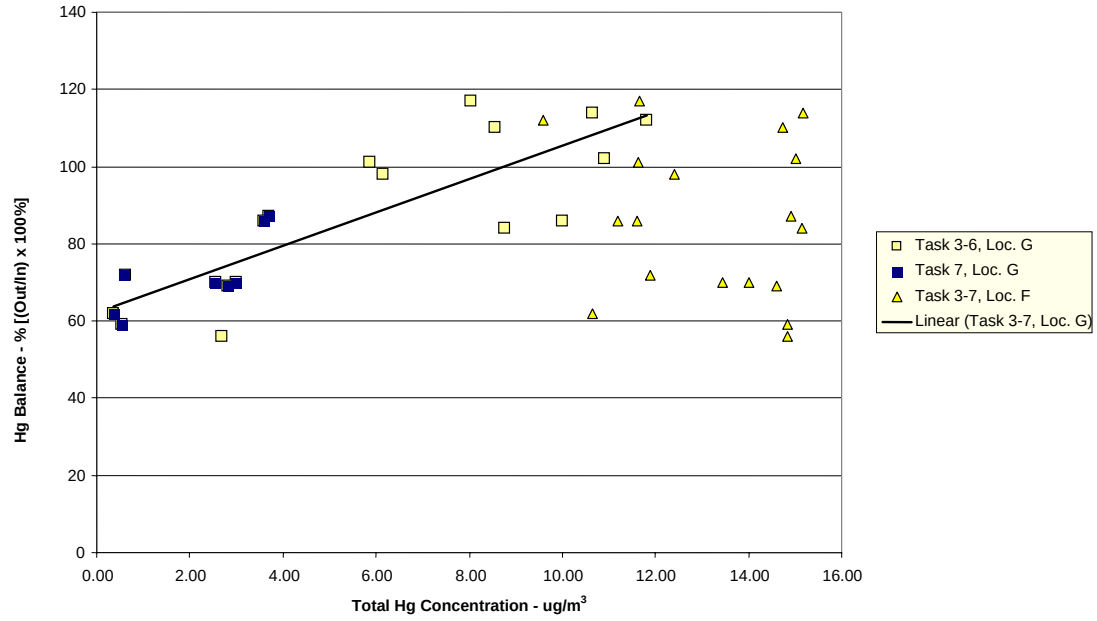


Figure 8. Mercury material balance closure versus total mercury concentration at the ESP flue gas outlet (Location G) with the total mercury measured at the ESP inlet (Location F)

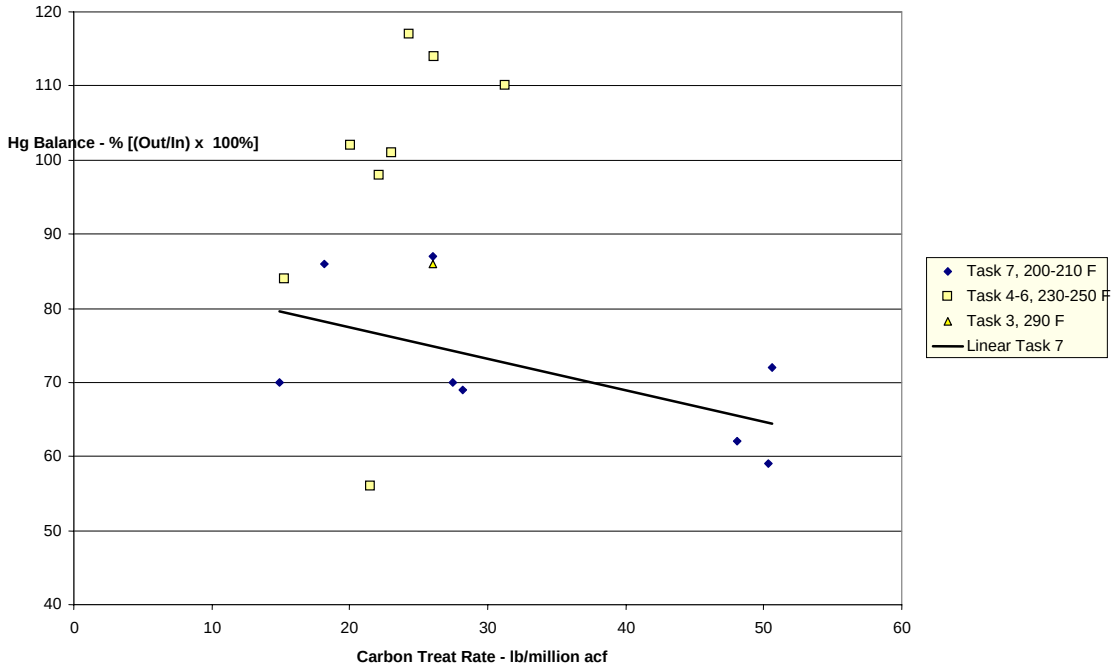


Figure 9. Mercury material balance closure versus Carbon Treat Rate

The lowered mercury material balance closures would appear to indicate that mercury is accumulating in the ESP and/or the mercury concentration measured on the fly ash sample collected from the ESP hopper (sampled at Location I) is too low. The fact the mercury material balance closure declined during the long-term test seems to indicate that mercury material balance closure decrease is most likely related to the same process that is increasing mercury removal across the ESP (see Figure 6). If a portion of the fly ash sample from the ESP hopper is being lost consistently, then we would expect the amount of mercury lost to go up with removal since more mercury is in the fly ash. A further examination of fly ash data and the ESP operation are required in order to resolve this question.

The flue gas mercury measurement is not a substantial source of error in the mercury balances at high capture rates for the following reason. At higher capture rates, there is less mercury in the flue gas and more in the ESP ash. While it is true that the mercury concentration measurement is prone to more relative error as the detection limit is approached, the absolute error in concentration is small. The mercury mass balance becomes dominated by the ESP ash mercury content and, thus, flue gas measurement errors do not have a substantial impact on the total mercury mass balance. For example, in Task 7, test 7-5, the mercury removal was 96% and the total mercury mass balance was 59%. The flue gas concentration was 0.54 µg/m^3. If the flue gas measurement were doubled to1.08 µg/m^3 (representing 100% error in the flue gas measurement), the mercury balance would be 63%. In order for the mercury mass balance to be 100%, the flue gas concentration would have to be 5.4 µg/m^3, a factor of

10 higher; it is highly unlikely that the flue gas measurement is in error by this much. Clearly, most of the mercury balance error is in the ESP ash sample. Collection of a representative ESP ash sample is difficult at best. The sample is not homogeneous; black particles, presumably high in carbon content, are clearly visible in the collected samples. These black particles are likely higher in mercury content than the particles containing less carbon. Fly ash carbon also tends to be lighter (less dense) than non-carbon fly ash. When there is a large density difference, the inertial collection device used for sample collection is biased toward collecting more of the heavy particles than the lighter particles. The result is a sample that does not adequately represent the amount of mercury captured on the fly ash.

Mercury and Carbon in Fly Ash at Pilot Plant During OH Sampling

During the Ontario Hydro (OH) sampling runs fly ash samples were collected in a thimble filter included in the sampling train at the pilot ESP inlet (Location F), from the pilot ESP hopper (Location I) using a sampling system shown in Figure 10, and a middle hopper of the host station #2 ESP. A diagram of the Ontario Hydro sampling train is shown in Figure 2 in Appendix A. Additional fly ash samples were collected periodically during long-term testing (Tasks 3 and 7) from the pilot ESP and host station ESP. The lab analysis of all the fly ash samples from the pilot and station ESP are listed in Table 6. The lab analysis of all the fly ash samples from the Ontario Hydro filter thimbles are listed in Table 7. The lab analyses of accumulated fly ash from ESP field #1 are listed in Table 8.

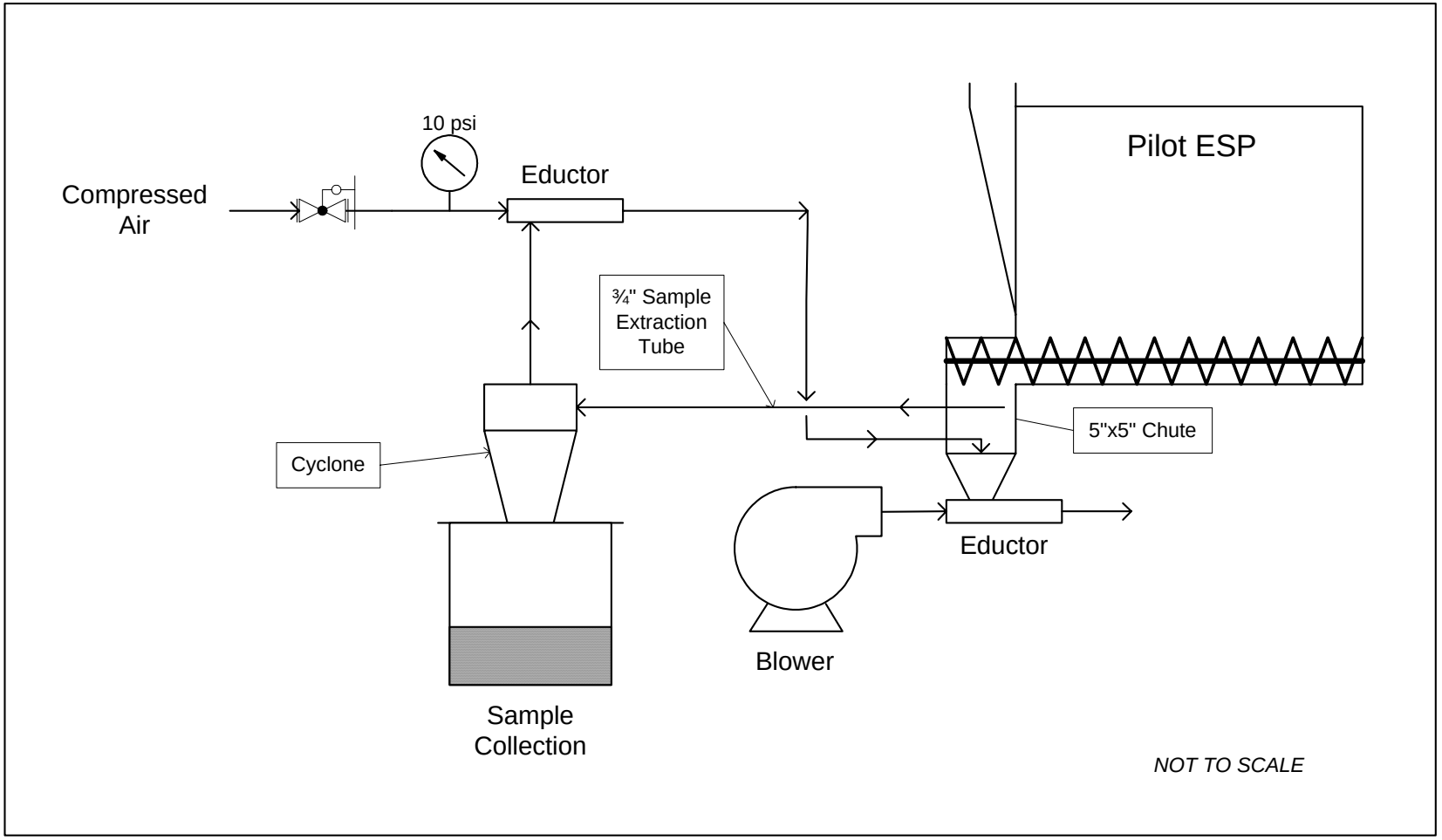


Figure 10. Pilot ESP Fly Ash Sampling System at Location I

Table 6. Pilot ESP and Host Station ESP Fly Ash Lab Analysis

					SOLIDS ANALYSIS													
OH Run Number	Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
					%	(dry)%	(dry)%	ppm	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%
				Task 3														
	20032914	4 Weekly	9/18/03	Pilot ESP	0.21	94.80	4.41	0.170	47.70	20.79	1.01	17.62	3.60	0.80	0.59	1.88	0.34	1.11
	20033001	8	9/25/03	Pilot ESP	1.34	91.95	6.02	0.440										
	20033018	9	9/26/03	Pilot ESP	1.21	91.25	7.35	0.340										
	20033054	11	9/29/03	Pilot ESP	0.48	96.34	2.62	0.110										
	20033086	13	9/30/03	Pilot ESP	0.71	94.98	4.88	0.280										
	20033114	15	10/1/03	Pilot ESP	0.99	94.11	4.28	0.160										
	20033197	17	10/2/03	Pilot ESP	0.43	93.81	5.1	0.160										
	20033216	19	10/3/03	Pilot ESP	0.86	93.08	5.85	0.220										
	20033251	21	10/6/03	Pilot ESP	0.67	94.41	4.98	0.160										
	20033290	23	10/7/03	Pilot ESP	0.73	94.18	5.81	0.190										
	20034092	25	12/17/03	Pilot ESP	0.13	80.07	18.95	0.730										
3-2	20040365	28	1/29/04	Pilot ESP	1.05	92.97	7.15	0.320										
	20034094	27	12/17/03	Station ESP	1.31	91.82	8.24	0.340										
	20040366	29	1/29/04	Station ESP	1.29	92.28	7.54	0.310										
				Task 4														
4-1	20041419	40	2/24/04	Pilot ESP	0.40	90.86	8.42	0.670										
4-1	20041421	44	2/27/04	Pilot ESP	0.95	89.73	9.61	0.780										
4-3	20041423	47	3/1/04	Pilot ESP	0.64	90.46	7.86	0.670										
	20041420	41	2/24/04	Station ESP	0.11	92.30	7.01	0.270										
	20041422	45	2/27/04	Station ESP	0.01	93.27	5.59	0.200										
	20041424	49	3/1/04	Station ESP	0.01	94.13	5.01	0.210										
				Task 5														
5-1	20041590	59	3/24/04	Pilot ESP	1.98	92.64	5.95	0.620										
5-2	20041592	63	3/25/04	Pilot ESP	2.48	91.10	8.39	0.850										
5-3	20041596	67	3/25/04	Pilot ESP	1.66	90.26	8.59	0.800										
	20043369	67		Pilot ESP "Repeat"		90.32	8.52	0.800										
	20041591	60	3/24/04	Station ESP	0.15	90.21	8.65	0.300										
	20041593	64	3/25/04	Station ESP	0.16	89.14	9.48	0.270										
	20041597	68	3/25/04	Station ESP	0.16	89.62	8.89	0.230										

Table 6. Pilot ESP and Host Station ESP Fly Ash Lab Analysis (cont'd.)

					SOLIDS ANALYSIS													
OH Run Number	Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
				Task 6														
6-2	20041858	76	4/13/04	Pilot ESP	2.49	87.40	11.02	0.870										
6-3	20041860	78	4/13/04	Pilot ESP	2.58	88.73	9.83	0.860										
	20042133	82	4/13/04	Pilot ESP	1.91	89.44	7.54	0.560										
	20041729	73	4/1/04	Station ESP	0.47	88.33	10.81	0.100										
	20041859	77	4/13/04	Station ESP	0.26	88.22	11.41	0.210										
	20041861	79	4/13/04	Station ESP	0.27	86.59	12.72	0.230										
				Task 7														
	20044985	87	08/25/04	Pilot ESP	1.42	79.76	17.87	0.778	37.58	18.64	0.80	14.39	4.25	1.87	1.00	1.39	0.33	1.79
	20044987	91	08/31/04	Pilot ESP	1.87	81.38	15.36	1.190	38.41	19.08	0.83	13.39	4.38	2.45	1.04	1.35	0.38	2.30
	20044989	95	09/01/04	Pilot ESP	1.75	83.78	13.92	1.060	38.87	19.50	0.85	13.05	4.59	2.65	1.11	1.37	0.42	2.51
	20044991	98	09/02/04	Pilot ESP	0.80	83.04	15.85	0.947	40.65	19.73	0.88	12.70	4.02	2.28	0.95	1.56	0.39	1.48
	20044993	103	09/03/04	Pilot ESP	0.80	82.34	16.65	0.955	39.62	19.29	0.87	12.90	4.17	2.17	0.96	1.47	0.41	1.52
7-1	20044995	106	09/08/04	Pilot ESP	0.92	84.30	14.65	0.810	42.63	20.03	0.92	12.43	3.35	1.90	0.72	1.75	0.42	1.31
7-2	20044997	110	09/09/04	Pilot ESP	1.55	90.70	7.22	1.090	46.55	22.10	1.02	10.24	3.27	2.78	0.71	2.00	0.44	2.04
7-3	20044999	112	09/09/04	Pilot ESP	1.80	91.67	5.53	0.990	47.34	22.88	1.02	9.21	2.86	2.74	0.67	2.18	0.34	2.28
	20050038	123	12/09/04	Pilot ESP	1.58	88.50	10.97	0.795	41.05	19.00	0.84	20.99	2.30	1.77	0.46	1.62	0.16	1.73
	20050040	127	12/10/04	Pilot ESP	1.05	88.87	10.67	0.902	41.92	19.82	0.90	17.82	2.47	1.68	0.49	1.73	0.18	1.38
	20050042	130	12/10/04	Pilot ESP	1.41	93.43	5.82	0.787	44.36	20.87	0.96	19.06	2.69	1.99	0.51	1.81	0.19	1.75
7-4	20050044	135	12/15/04	Pilot ESP	1.01	88.59	10.62	0.742	44.81	20.86	1.00	13.82	2.57	1.65	0.53	1.88	0.20	1.12
7-5	20050048	138	12/15/04	Pilot ESP	1.08	88.96	10.7	0.770	44.47	20.77	1.01	13.20	2.60	1.69	0.52	1.84	0.21	1.12
7-6	20050052	143	12/16/04	Pilot ESP	1.26	92.13	7.34	0.799	45.92	21.56	1.04	13.02	2.71	1.91	0.52	1.89	0.22	1.55
7-7	20050056	147	12/16/04	Pilot ESP	1.27	93.34	5.82	0.734	46.62	21.93	1.06	13.14	2.78	1.96	0.54	1.96	0.22	1.65
7-8	20050060	151	12/17/04	Pilot ESP	0.26	92.24	7.21	0.746	46.39	22.23	1.00	14.15	2.62	1.66	0.54	1.91	0.21	1.37
	20050064	155	12/22/04	Pilot ESP	0.31	88.00	11.99	0.670	38.32	18.55	0.84	22.07	2.90	1.75	0.55	1.50	0.15	1.47
	20044986	88	08/25/04	Station ESP	0.43	81.38	16.87	0.370	35.42	17.94	0.79	19.81	3.61	0.74	0.81	1.40	0.37	1.75
	20044988	92	08/31/04	Station ESP	0.44	82.94	15.89	0.382	35.90	18.21	0.82	19.66	4.21	0.80	0.98	1.33	0.47	1.66
	20044990	96	09/01/04	Station ESP	0.39	82.90	16	0.366	35.80	18.51	0.84	19.07	4.47	0.83	1.06	1.34	0.54	1.81
	20044992	99	09/02/04	Station ESP	0.23	82.11	17	0.408	34.30	17.43	0.79	22.45	4.17	0.76	0.92	1.25	0.46	1.58
	20044994	104	09/03/04	Station ESP	0.36	81.50	17.81	0.458	35.81	17.89	0.81	19.63	3.98	0.76	0.86	1.34	0.47	1.44
	20044996	107	09/08/04	Station ESP	0.24	84.10	15.14	0.470	37.81	18.33	0.85	20.26	3.40	0.73	0.67	1.51	0.47	1.41

Table 6. Pilot ESP and Host Station ESP Fly Ash Lab Analysis (cont'd.)

					SOLIDS ANALYSIS													
OH Run Number	Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
	20044998	111	09/09/04	Station ESP	0.40	80.76	18.08	0.900	36.70	18.32	0.85	14.90	2.85	0.70	0.64	1.67	0.47	1.23
	20045000	113	09/09/04	Station ESP	0.39	79.76	18.17	1.110	38.56	19.38	0.91	13.68	2.90	0.75	0.67	1.76	0.52	1.56
	20050039	124	12/09/04	Station ESP	0.32	87.80	10.76	0.302	41.69	19.96	0.92	20.05	2.35	0.71	0.51	1.73	0.22	1.36
	20050041	128	12/10/04	Station ESP	0.68	88.08	10.28	0.339	41.20	20.28	0.95	19.68	2.43	0.73	0.53	1.77	0.26	1.84
	20050043	131	12/10/04	Station ESP	0.49	76.90	22.48	1.020	36.47	17.82	0.82	18.62	2.16	0.64	0.45	1.51	0.24	1.13
	20050046	136	12/15/04	Station ESP	0.20	79.17	21.38	0.808	38.41	18.28	0.85	18.05	2.22	0.65	0.45	1.06	0.22	1.07
	20050050	139	12/15/04	Station ESP	0.26	78.89	22.11	0.735	37.59	17.88	0.85	16.59	2.11	0.63	0.42	1.52	0.21	0.85
	20050054	144	12/16/04	Station ESP	0.22	82.65	17.09	0.799	38.83	18.63	0.90	17.23	2.26	0.67	0.44	1.61	0.23	0.93
	20050058	148	12/16/04	Station ESP	0.39	86.77	12.18	1.070	42.52	20.92	1.06	14.68	2.65	0.81	0.55	1.89	0.38	1.39
	20050062	152	12/17/04	Station ESP	0.24	88.06	10.82	0.648	43.02	21.16	1.07	15.11	2.63	0.81	0.55	1.91	0.37	1.46
	20050066	156	12/22/04	Station ESP	0.37	75.46	24.62	0.785	33.22	17.02	0.80	18.27	2.50	0.63	0.53	1.41	0.25	1.54

Table 7. Ontario Hydro Filter Thimble Fly Ash Lab Analysis

					SOLIDS ANALYSIS													
OH Run Number	Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
					%	(dry)%	(dry)%	ppm	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%
				Task 3														
	20040403	A-3-2-JAW	1/29/04	THIMBLE 21 (Loc. A)	0.17	92.71	6.64	0.05	45.91	19.38	1.00	16.75	4.40	0.75	0.53	1.78	0.41	1.00
	20040404	B-3-2-BPS	1/29/04	THIMBLE 28 (Loc. B)	0.21	92.82	5.96	0.28	46.01	19.26	1.00	16.71	4.42	0.74	0.52	1.76	0.39	1.01
3-2	20040405	F-3-2-JEL	1/29/04	THIMBLE 35 (Loc. F)	0.21	92.74	6.28	0.37	46.92	19.75	1.03	15.38	4.43	0.77	0.54	1.81	0.42	1.13
	20040409	A-3-3-JAW	1/29/04	THIMBLE 55 (Loc. A)	0.13	92.19	6.79	0.06	44.97	18.88	0.98	16.64	4.28	0.74	0.49	1.69	0.39	0.98
	20040410	B-3-3-BPS	1/29/04	THIMBLE 62 (Loc. B)	0.17	92.34	6.65	0.33	45.84	19.27	0.99	17.34	4.31	0.74	0.53	1.85	0.38	1.05
3-3	20040411	F-3-3-JEL	1/29/04	THIMBLE 69 (Loc.F)	0.22	92.09	7.00	0.59	46.36	19.46	1.01	14.74	4.33	0.76	0.52	1.81	0.41	1.03
				Task 4														
4-1	20041200	1	2/24/04	THIMBLE (Loc. F)	0.33	91.49	7.15	1.240	47.36	21.83	1.03	10.04	3.27	1.79	0.72	2.11	0.34	1.35
4-2	20041202	18	2/27/04	THIMBLE (Loc. F)	0.36	90.82	7.69	1.410	46.97	21.12	1.10	11.06	3.07	2.01	0.57	1.91	0.30	1.37
4-3	20041204	32	3/1/04	THIMBLE (Loc. F)	0.30	91.78	7.08	1.330	47.85	21.56	1.12	10.83	3.34	1.91	0.54	1.93	0.29	1.42
				Task 5														
5-1	20041581	1	3/24/04	THIMBLE (Loc. F)	0.46	93.33	5.20	1.480	43.80	19.18	0.99	17.09	3.03	3.70	0.47	1.62	0.25	2.87
5-2	20041583	14	3/25/04	THIMBLE (Loc. F)	0.53	91.98	5.90	1.710	42.18	18.79	0.96	18.13	2.95	3.78	0.46	1.57	0.26	2.85
5-3	20041585	27	3/25/04	THIMBLE (Loc. F)	0.65	92.22	5.64	1.700	42.02	18.75	0.97	17.63	2.85	3.70	0.48	1.62	0.26	2.47
				Task 6														
	20041847	XX	4/1/04	THIMBLE (Loc. E)	0.38	92.6	5.64	0.360	38.58	18.57	0.88	23.23	2.77	2.95	0.44	1.67	0.23	2.89
6-1	20041848	XX	4/1/04	THIMBLE (Loc. F)	1.03	92.69	5.28	0.880	38.04	18.49	0.89	21.75	2.77	3.26	0.46	1.68	0.25	3.33
	20041850	XX	4/13/04	THIMBLE (Loc. E)	0.66	89.12	10.36	1.510	36.86	18.11	0.87	22.35	2.96	2.95	0.43	1.59	0.26	2.09
6-2	20041851	XX	4/13/04	THIMBLE (Loc. F)	1.50	88.6	9.44	1.680	36.49	18.19	0.87	20.64	2.93	3.31	0.45	1.61	0.26	2.36
	20041853	XX	4/13/04	THIMBLE (Loc. E)	1.55	90.49	8.28	1.670	39.21	19.41	0.87	20.27	2.86	3.12	0.45	1.53	0.27	2.31
6-3	20041854	XX	4/13/04	THIMBLE (Loc. F)	1.57	89.26	8.98	1.690	38.16	18.97	0.85	20.38	2.86	3.11	0.46	1.46	0.26	2.36

Table 7. Ontario Hydro Filter Thimble Fly Ash Lab Analysis (cont'd.)

					SOLIDS ANALYSIS													
OH Run Number	Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
				Task 7														
7-1	20044848	1-2	9/8/04	THIMBLE (Loc. F)	1.44	80.63	16.05	1.070	39.49	18.97	0.88	11.79	3.21	2.69	0.76	1.77	0.44	1.29
7-2	20044850	3	9/9/04	THIMBLE (Loc. F)	1.32	90.95	5.36	1.260	46.34	22.12	1.02	9.65	3.20	3.26	0.77	2.15	0.43	2.15
7-3	20044852	4-6	9/9/04	THIMBLE (Loc. F)	1.38	90.79	5.48	1.430	46.61	22.40	1.05	8.67	2.83	3.75	0.66	2.20	0.38	2.15
7-4	20050068	1	12/15/04	THIMBLE (Loc. F)	0.63	87.39	10.75	0.858	43.23	20.73	1.00	13.11	2.50	2.11	0.52	1.82	0.24	1.14
7-5	20050071	2	12/15/04	THIMBLE (Loc. F)	0.71	87.39	10.71	0.892	43.48	21.01	1.01	13.03	2.54	2.24	0.54	1.86	0.24	1.23
7-6	20050074	3	12/16/04	THIMBLE (Loc. F)	0.51	91.46	6.38	1.050	44.53	21.64	1.05	12.91	2.71	2.58	0.54	1.87	0.26	1.87
7-7	20050077	4	12/16/04	THIMBLE (Loc. F)	0.73	92.66	5.22	1.110	45.69	22.30	1.08	12.47	2.81	2.79	0.56	1.93	0.28	2.07
7-8	20050080	5	12/17/04	THIMBLE (Loc. F)	0.27	92.97	5.82	0.948	45.72	22.05	1.07	13.41	2.67	2.36	0.55	1.90	0.26	1.71

Figure 11 shows a plot of mercury concentration versus the percent carbon in all fly ash samples taken from the pilot ESP at the three different pilot plant conditions and from the host plant ESP during the entire test program. The regression lines for the data from the pilot plant during baseline testing (Task 3) and from the host plant during all Tasks (Tasks 3-7) are very similar; this is expected since the temperature conditions are similar. The slopes of the lines indicate that mercury content in the fly ash, and thus mercury capture, increases as the carbon content of the fly ash increases.

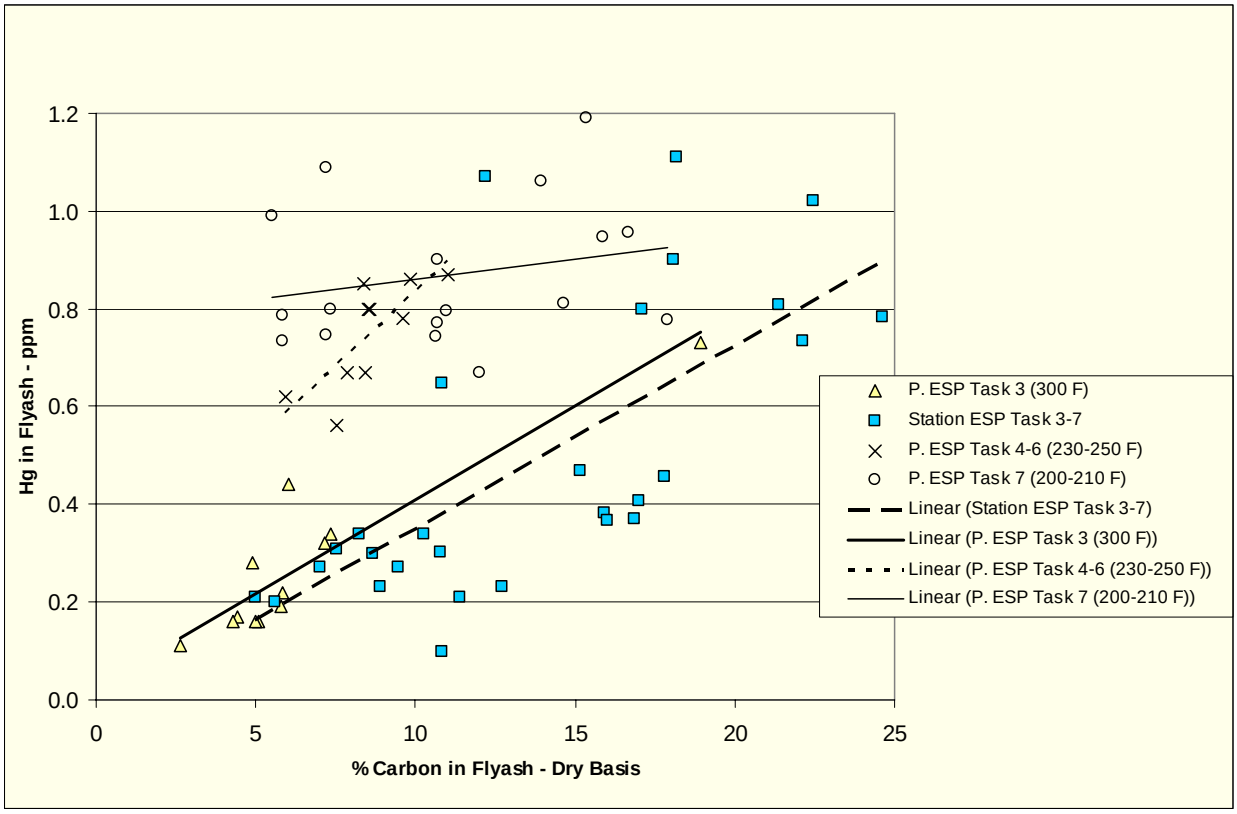


Figure 11. Mercury Concentration versus Carbon in all Pilot ESP & Station Fly Ash Samples

The data from the short-term intermediate temperature conditions (Task 4-6) and long-term low temperature conditions (Task 7) show increased fly ash concentrations of mercury at lower temperature for a given amount of carbon. Overall Figure 11 indicates that lowering the flue gas temperature increases mercury capture. For Tasks 4-6 and 7 scatter in the data seems to have increased while the slope of the regression line for Task 4-6 increased and Task 7 decreased when compared to baseline (Task 3). In addition, the low mercury material balance closure around the pilot ESP, discussed earlier, indicates that concentrations of mercury in the fly ash should be higher, especially for Task 7 data. A higher concentration would have closed the balance.

Durham[5] also reported that mercury capture on native fly ash improves with increasing loss on ignition (LOI, a surrogate for carbon content) and with decreasing flue gas temperature, although the range of LOI concentrations and the range of temperatures

Durham examined were both higher than those examined in this work.

Figure 12, like Figure 11, shows a plot of mercury concentration versus the percent carbon in fly ash samples taken from the pilot ESP at the three different pilot plant conditions and from the host plant (station) ESP, but Figure 12 shows only those data taken during Ontario Hydro mercury sampling at the pilot ESP. This more-limited set of data also shows increased mercury concentrations and increased scatter as flue gas temperatures are lowered.

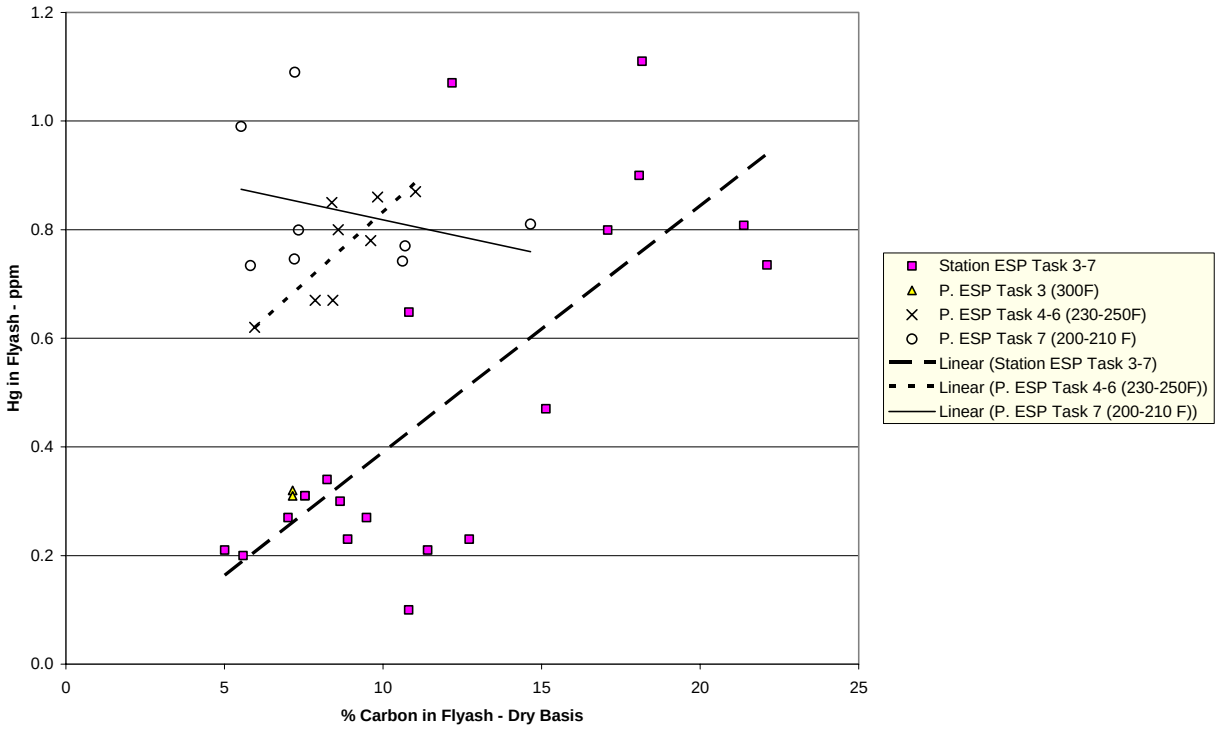


Figure 12. Mercury Concentration versus Carbon in Pilot ESP Fly Ash Samples during Ontario Hydro Mercury Sampling

Figure 13 is a comparison of the percent carbon in fly ash collected at the pilot ESP inlet (Location F) by a thimble filter included in the Ontario Hydro sampling train to the percent carbon in the fly ash at the pilot ESP hopper collected by the sampling system (Location I) shown in Figures 2 and 10. In a majority of the sample runs the amount of carbon in the fly ash sample from the ESP hopper exceeds the amount of carbon in the fly ash collected at the ESP inlet (Location F). During short term tests (Tasks 4-6) this pattern appears to be very consistent, but during long-term tests (Task 7) the pattern is less consistent. Figure 14 is a plot of the same data as in Figure 13 as a relative percent difference of the carbon in the fly ash according to the mercury material balance closure. Figure 14 appears to show that more carbon was in the fly ash collected by the ESP during Tasks 3-6 than what entered the ESP, while Task 7 shows a wider range and more data at zero, but worsening mercury balances. (See section under next heading for discussion of this).

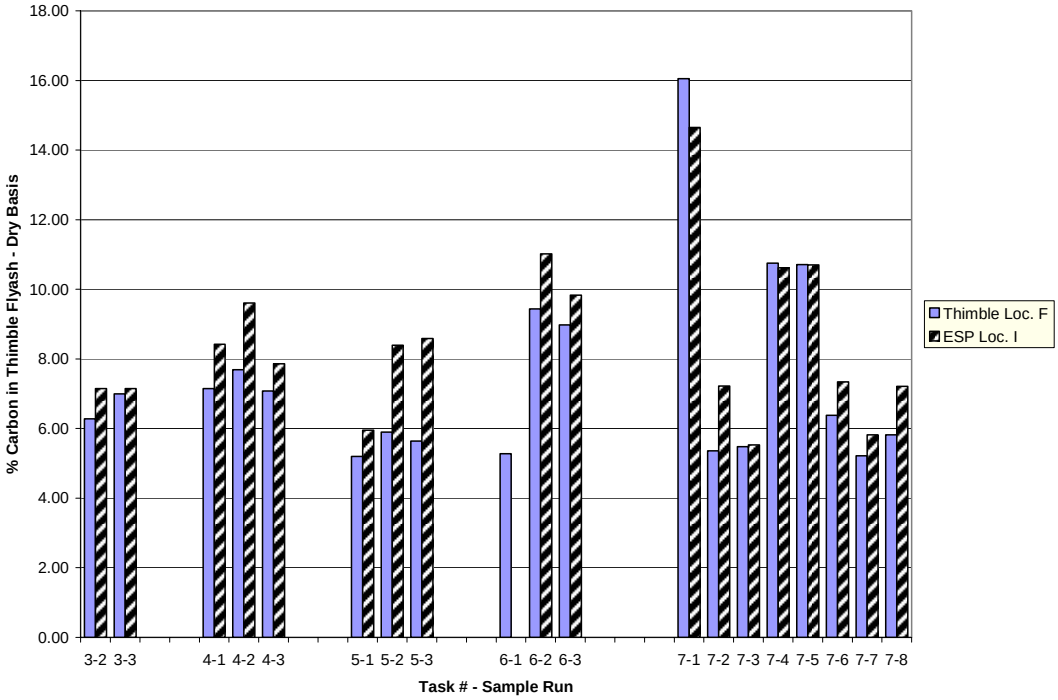


Figure 13. Comparison of Carbon in Fly Ash from Thimble at pilot ESP Flue Gas Inlet and ESP Hopper Sampling System

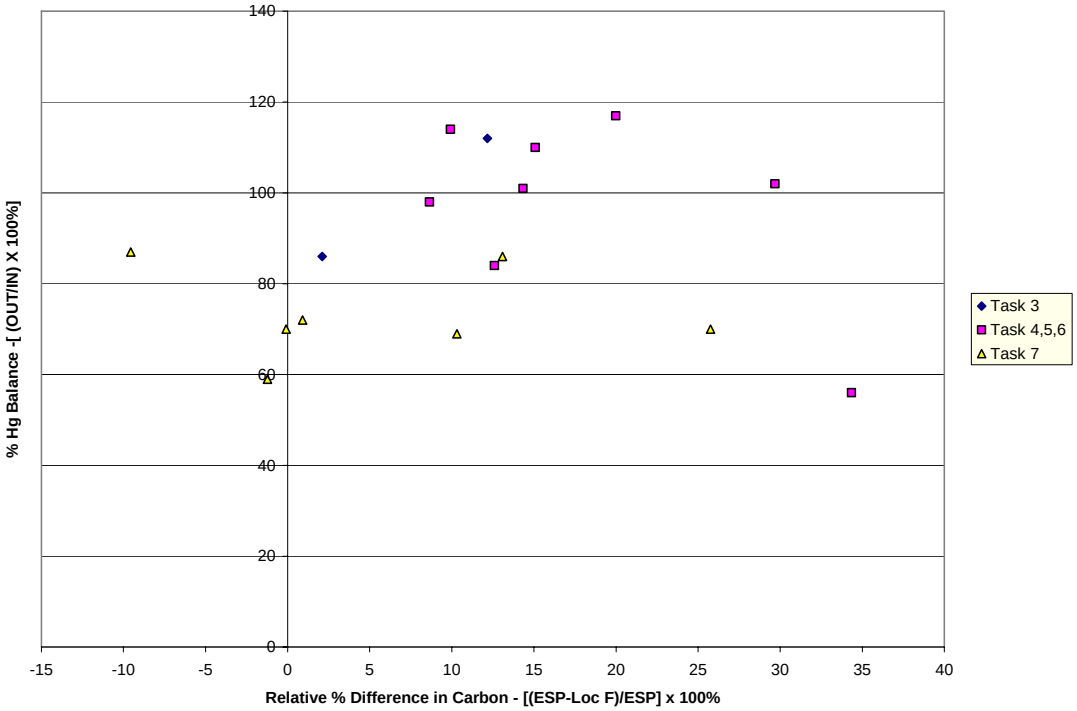


Figure 14. Mercury Balance vs Relative Carbon Difference in Fly Ash - Pilot ESP Hopper Sample (Loc. I) to ESP Flue Gas Inlet (Loc. F) Thimble

Mercury Absorption in the Pilot ESP

Figures 11 and 12 indicate that the mercury concentrations in the fly ash samples from the pilot ESP hopper collected by the sampling system (Location I) become more scattered as gas temperatures are reduced to 200 °F. In addition, it appears that the scatter is worse for the long-term tests. Figures 12 and 13 indicate that the carbon contents of the fly ash samples from the pilot ESP hopper collected by the sampling system (Location I) are not always consistent with the carbon content of the fly ash entering the ESP. The scatter in mercury concentration and differences in carbon are likely due to the tendency of fly ash to accumulate over time on the collector plates (CP), Teflon barriers, and other surfaces inside the pilot ESP, then slough off in slabs. Figure 16 shows areas of fly ash accumulation and sloughing on the collector plate that occurred during long-term testing (Task 7). Figure 17 shows areas of fly ash accumulation and sloughing on the Teflon barrier that occurred during long-term testing (Task 7).

Figure 15 is a comparison of the percent MgO in fly ash collected by the thimble filter included in the Ontario Hydro sampling train (Task 7) at the pilot ESP inlet (Location F) to the percent MgO in the fly ash at the pilot ESP hopper collected by the sampling system (Location I) shown in Figures 2 and 10. During the Task 7 sample runs the amount of MgO in the fly ash sample from the ESP hopper is less than the amount of MgO in the fly ash collected at the ESP inlet. The fly ash sample from the ESP inlet is likely to have MgO as a constituent of the ash particles and as separate particles as a result of $Mg(OH)_2$ injected into the flue gas ahead of the air heater. The comparison shown in Figure 15 indicates that the fly ash sampling system (Location I) shown in Figure 9 may be losing the smaller size fraction. This is expected since cyclones will tend to lose smaller, lighter weight particles. In addition the positioning of the ¾" sample extraction tube in the 5"x5" ESP hopper chute could contribute to the loss of smaller, lighter weight particles. This may apply to the carbon and ash particles as well. Analyses of accumulated fly ash deposits taken from the ESP field #1 collector plate (CP), Teflon barrier, and high voltage (HV) pins, are listed in Table 8. The fly ash samples from the ESP sampling system (Figure 10) and Ontario Hydro thimble samples were collected during the last test run before the ESP was opened for inspection. The pilot ESP wall heaters were set at 150 °F from the end of the last run to the time that the ESP opened. The data in Table 8 and plotted in Figure 18 show that higher concentrations of mercury are in the accumulated fly ash deposits. The highest concentration of mercury was found on the Teflon barrier fly ash deposit; this deposit was not removed by the rappers and was therefore exposed to flue gas for a longer time. The smaller concentration of mercury found in the accumulated deposit on the collector plates and HV pins is most likely due to a shorter exposure time, since these deposits are periodically dislodged by the rappers, as they would do in a full-scale ESP.

The smaller concentration of mercury found at the ESP sampler during the last test run seems to show that the accumulations of fly ash in the ESP adsorb mercury over time. The absorption and non-uniform release of the accumulated fly ash deposits would help explain the consistently lower mercury material balance closures seen during the

Ontario Hydro mercury sampling runs as flue gas temperatures were lowered. The lower flue gas temperatures did increase the accumulation of fly ash deposits in the ESP, and would lead to the speculation that mercury is adsorbed by the fly ash deposits.

As the flue gas temperature decreases, fly ash deposits can accumulate more rapidly for two reasons. First, as the gas gets closer to the dew point, fly ash has a greater tendency to pick up moisture, especially if there is some gas temperature stratification (such as near the walls). As it picks up moisture, the fly ash becomes “stickier” and is more easily agglomerated. This increased moisture content also reduces the ash resistivity, which leads to more capture in the ESP fields. Second, the actual gas flow rate decreases (due to gas contracting when the temperature goes down), which increases the residence time of the fly ash in the ESP and, thus, increases the Specific Collection Area (SCA).

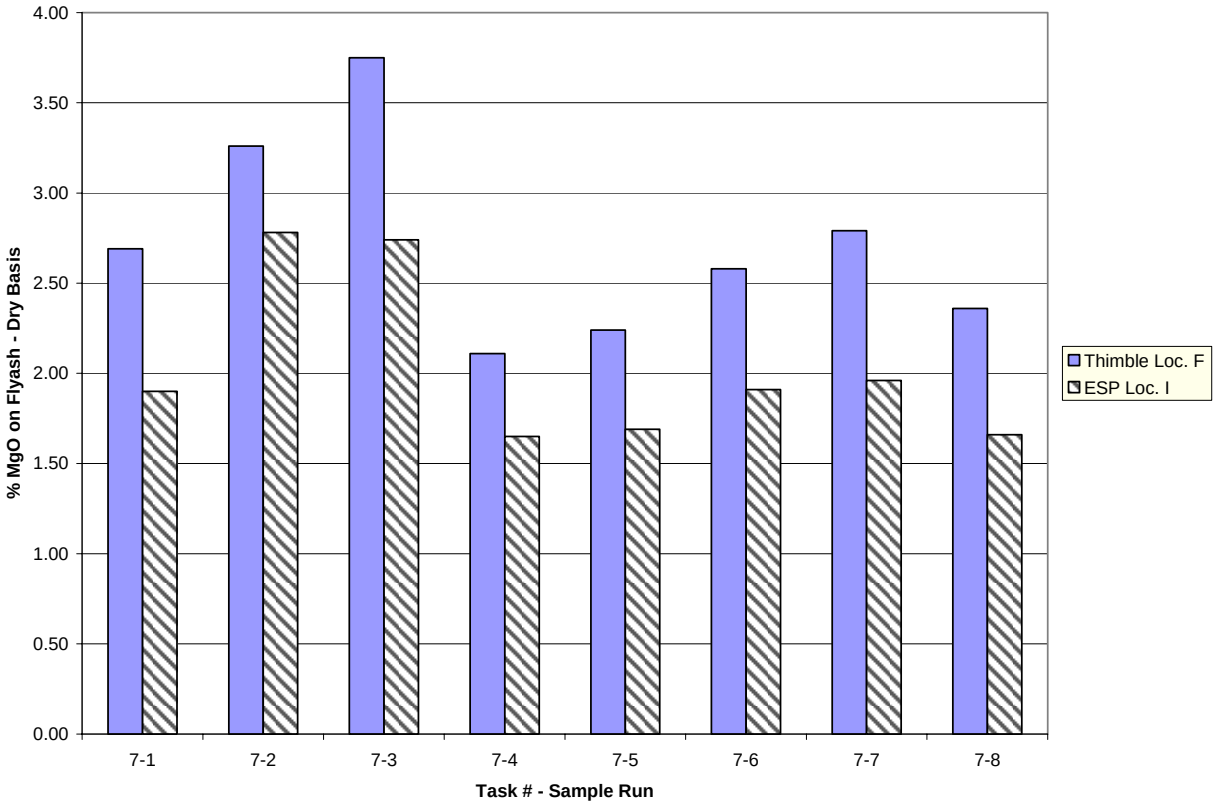


Figure 15. Comparison of MgO in Fly Ash from Pilot ESP Flue Gas Inlet Thimble and ESP Hopper Sampling System

Figure 16. Fly Ash Accumulation on Pilot ESP Collector Plate, Field #1

Figure 17. High Carbon Fly Ash Accumulation on Pilot ESP Teflon Barrier, Field #1

Table 8. Collector Plate, Teflon Barrier and HV Pin Fly Ash Analysis

		SOLIDS ANALYSIS			
Date	**Description**	**As Det. Moisture**	**ASH**	**C**	**As Det. Hg**
	Task 7	**%**	**(dry)%**	**(dry)%**	**ppm**
09/09/04	THIMBLE (Loc. F)	1.32	90.95	5.36	1.260
09/09/04	ESP Sampler	1.55	90.70	7.22	1.090
09/09/04	THIMBLE (Loc. F)	1.38	90.79	5.48	1.430
09/09/04	ESP Sampler	1.80	91.67	5.53	0.990
11/19/04	ESP #1 CP	1.05	92.56	4.65	1.490
11/19/04	ESP #1 Teflon	1.75	88.78	7.50	3.280
11/19/04	ESP #1 HV Pins	1.50	91.73	4.94	1.820

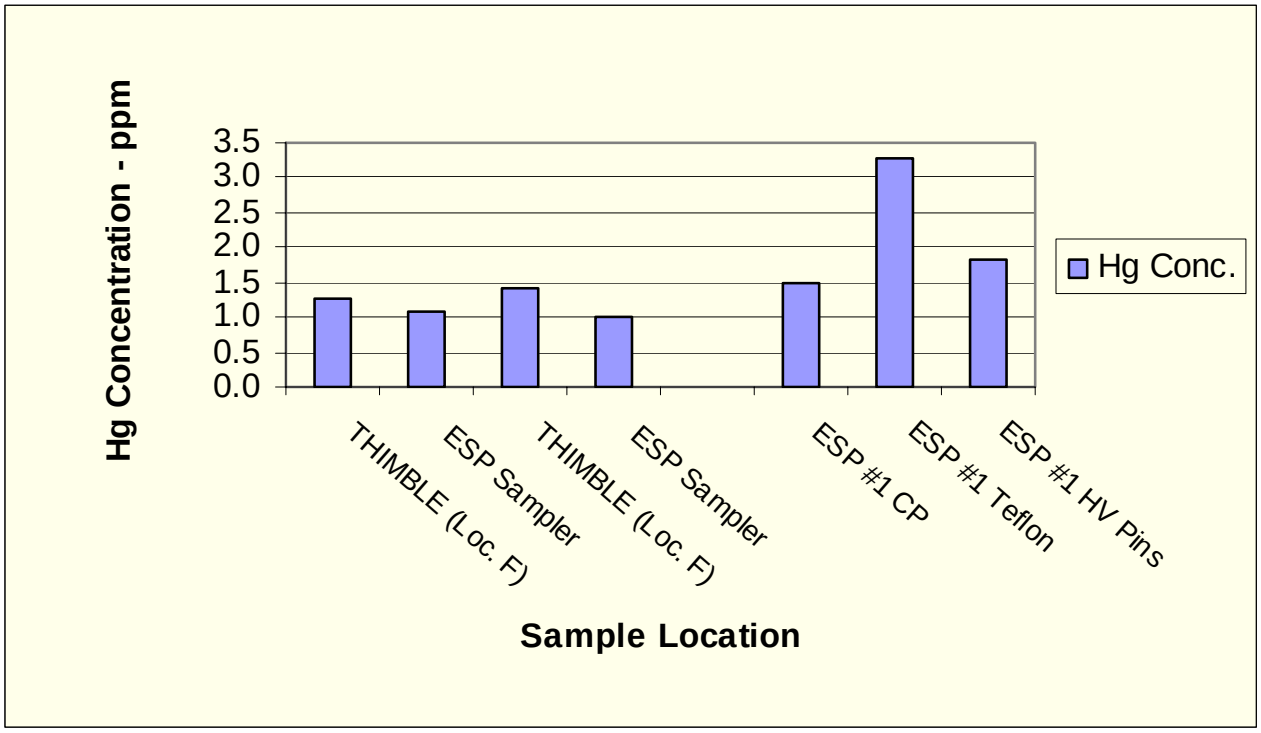


Figure 18. Mercury Concentrations in Fly Ash from Various Locations at Pilot ESP During OH ampling and on Pilot ESP Collector Plates, Teflon Barrier, and High Voltage Pins

Mercury and Carbon in Fly Ash at Pilot Plant and Host Plant

Fly ash samples were periodically collected for analysis from the pilot ESP hopper (Location I) using the sampling system shown in Figure 10, and the middle hopper of the host plant #2 ESP (Location J). The lab analysis data are listed in Table 6. Figure 19 shows mercury concentration in the pilot ESP fly ash versus flue gas temperature for all pilot fly ash samples collected during the entire test program (Task 3-7) and the graph within the graph shows the variation of the carbon in the fly ash versus the same temperatures. Figure 20 shows mercury concentration in the pilot ESP fly ash versus flue gas temperature for a select group of pilot fly ash samples with an average of 6.4% carbon that were collected during the entire test program (Task 3-7) and the graph within the graph shows the variation of the carbon in the fly ash versus the same temperatures. 6.4% average carbon was selected to include the broadest range of temperatures in order to demonstrate the effect of temperature at a relatively constant amount of carbon. Both Figures 19 and 20 clearly show the increased mercury concentration as flue gas temperature was lowered.

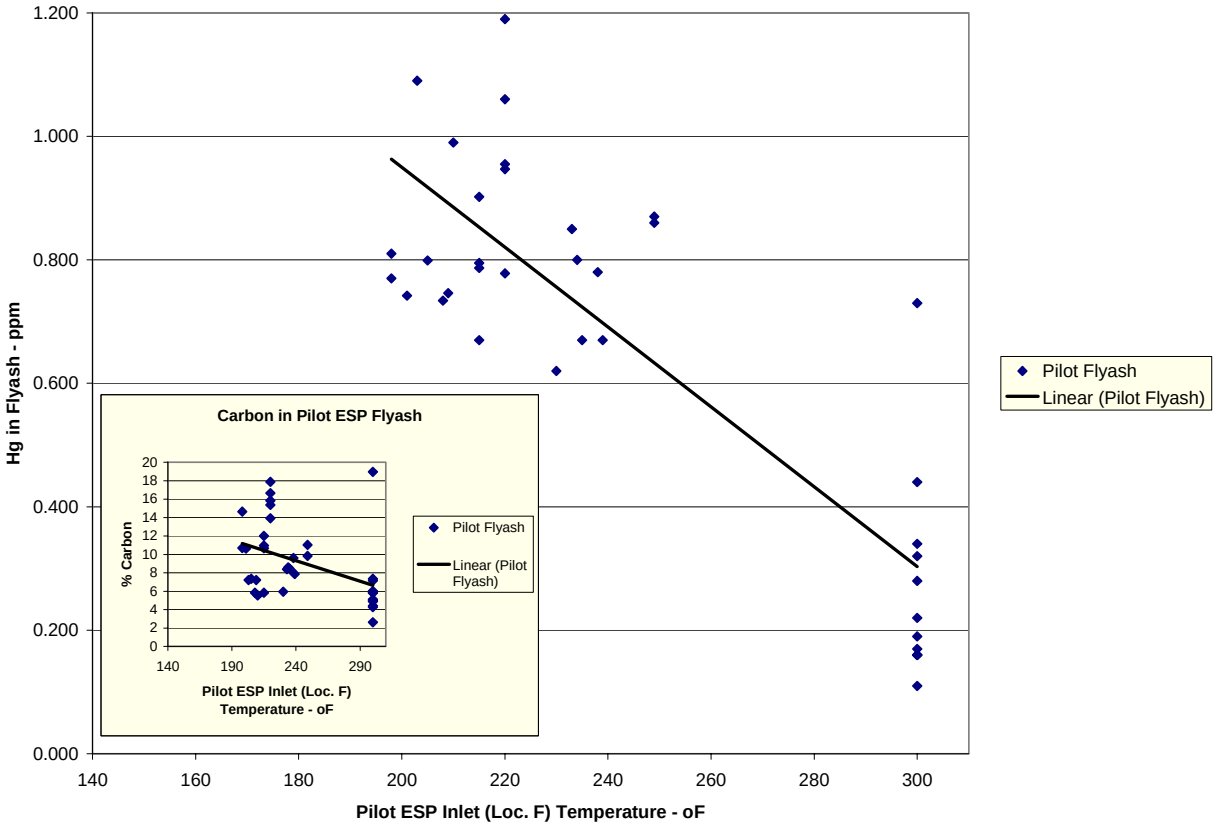


Figure 19. Mercury and Carbon versus Temperature in Pilot ESP Fly Ash

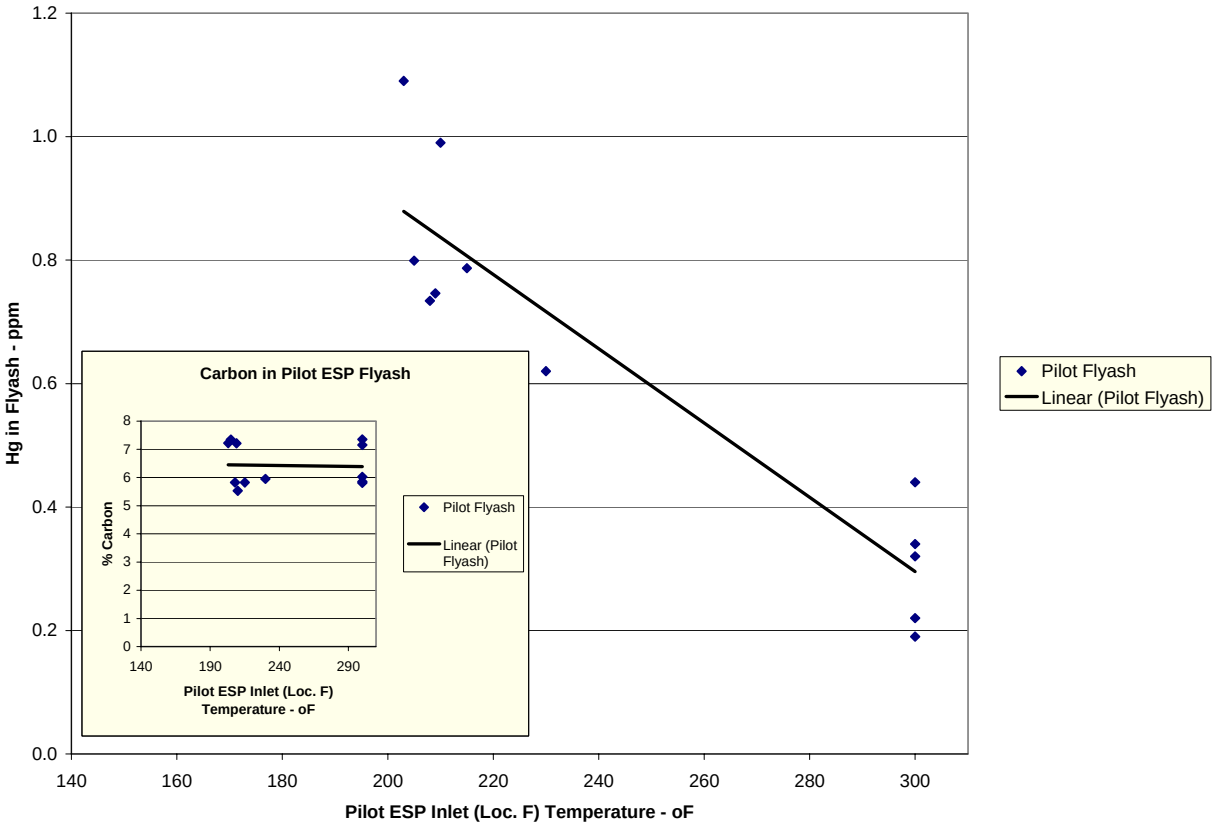


Figure 20. Mercury versus Temperature in Pilot ESP Fly ash at 5.5 to 7.3% Carbon

Figure 21 shows the mercury concentration in the host plant ESP #2 fly ash versus estimated flue gas temperature for all host plant fly ash samples collected during the entire test program (Task 3-7) and the graph within the graph shows the variation of the carbon in the fly ash versus the same temperatures. Figure 22 shows mercury concentration in the station ESP fly ash versus estimated flue gas temperature for a select group of station fly ash samples with an average of 17.1% carbon that were collected during the entire test program (Task 3-7) and the graph within the graph shows the variation of the carbon in the fly ash versus the same temperatures. 17.1% carbon was selected to include the broadest range of temperatures in order to demonstrate the effect of temperature at a relatively constant amount of carbon. The flue gas temperature was estimated by subtracting 300 degrees (estimated temperature drop across air heater) from the economizer outlet temperature recorded in the pilot plant flue extraction pipe at Location A. Both Figures 21 and 22 clearly show the increased mercury concentration on the fly ash as estimated flue gas temperature was lowered.

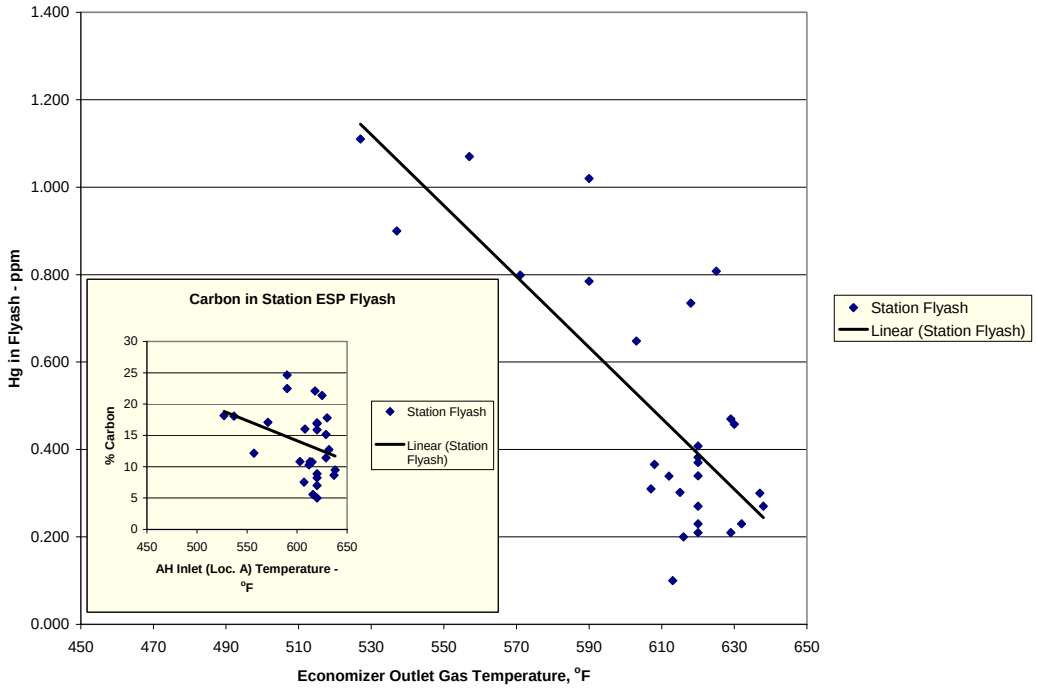


Figure 21. Mercury and Carbon in Station ESP Fly Ash Versus Economizer Outlet Temperature (Air heater outlet temperature can be estimated as being 300 °F lower).

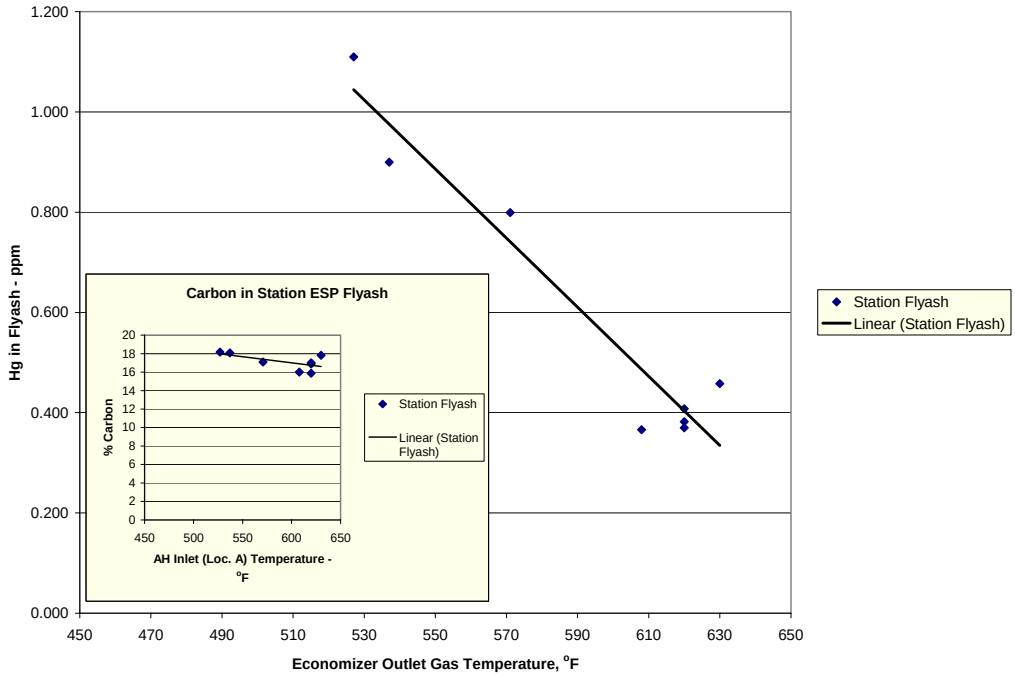


Figure 22. Mercury in Station ESP Fly Ash Versus Economizer Outlet Temperature at 15.5 to 18% Carbon (Air heater outlet temperature can be estimated as being 300 °F lower)

Figures 19 thru 22 demonstrate the effects of carbon in fly ash and flue gas temperature on mercury capture. They also show that the effects occurred both in the pilot plant and the host station. Figure 23 shows mercury concentration versus carbon in fly ash samples from the pilot and host plant ESPs at flue gas temperatures of only 210 °F and ≥300 °F. At ≥300 °F, the pilot ESP (Task 3 Baseline) and host plant ESP show very similar characteristics. The offset in the data plots between the data for the pilot and station ESPs at 300 °F is most likely due to the possibility that the station ESP was at a higher temperature, which would reduce mercury concentrations. The host plant ESP estimated flue gas temperature was based on the economizer outlet temperature of 620 °F. The data from the pilot ESP at 210 °F show considerable scatter and the linear plot of the data has a flatter slope. This is most likely due to absorption of mercury by accumulated fly ash deposits and then the episodic release of the fly ash deposits from the collector plates in the pilot ESP as flue gas temperatures were lowered. As expected the mercury concentrations plotted at 210 °F are higher than at 300 °F., but according to the lower Hg balances should have been even higher. This leads to the speculation that during a 2-hour Ontario Hydro (OH) sampling run the fly ash collected by the sampler was not the same fly ash that entered the ESP during OH sampling.

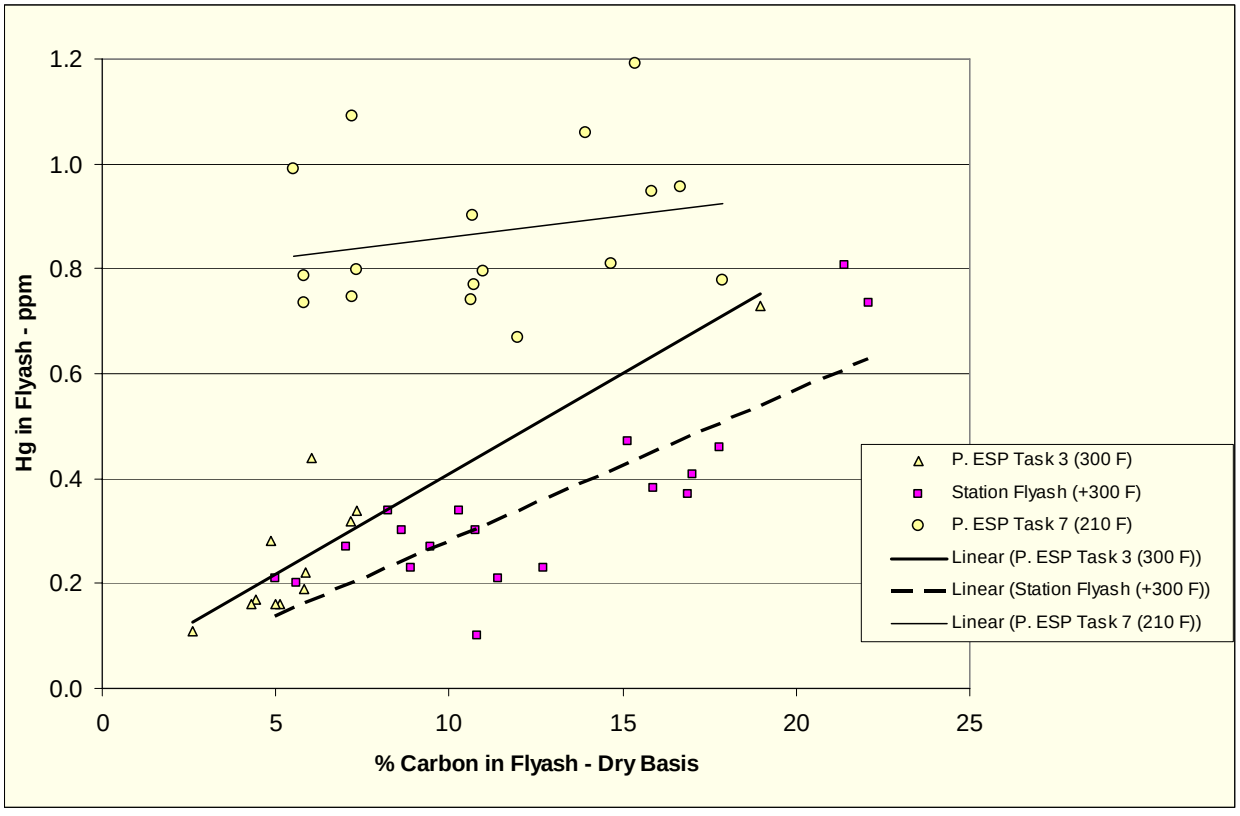


Figure 23. Mercury versus Carbon in Pilot and Station ESP's at 210 °F and 300 °F

Mercury Removal

Mercury removals of 61 to 96 percent were achieved during long-term testing (Task 7) at pilot ESP inlet temperatures of 200 - 210 °F. The host station operated over a broad range of conditions and produced a broad range of carbon in the fly ash. The mercury

removals are calculated from the Ontario Hydro mercury sampling done at the pilot ESP inlet and outlet (Locations F and G). A description of the conditions and measurement results is listed in Table 4 and further described in Appendix A. Figure 24 shows mercury removal (from gas sampling) versus percent carbon in the pilot ESP fly ash for the long-term (Task 7), short-term (Task 4-6) and baseline (Task 3) testing. The data plot shows increasing mercury removal as the flue gas temperature is reduced and as the amount of carbon in the fly ash increased during long-term (Task 7) testing with ESP inlet temperatures of 200-210 °F.

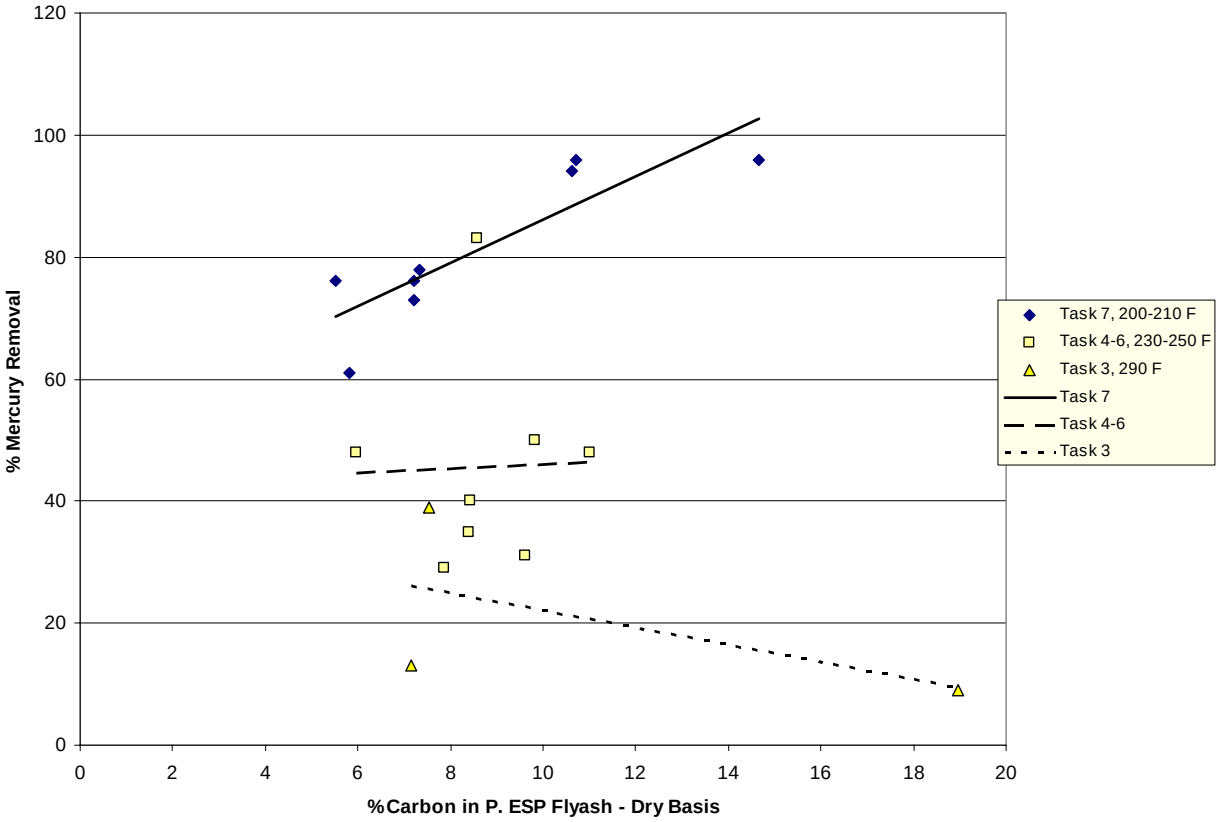


Figure 24. Mercury Removal from Pilot ESP Flue Gas at Various Fly Ash Carbon Contents (LOI)

The unburned carbon in the fly ash and the gas flow rate were used to calculate the "carbon treat rate", in a manner similar to that reported for mercury capture tests with powdered activated carbon injection (lbs of carbon per volume of treated gas). In this case, however, the carbon is simply the unburned carbon (LOI) in the fly ash that is native to the flue gas. The "carbon treat rate" is plotted in Figures 25 and 26 according to the amount of fly ash and flue gas measured at the ESP inlet for the actual and standard cubic feet of gas, respectively. The results from the long-term tests (Task 7) show a clear correlation between "carbon treat rate" and mercury removal. The results from the short-term tests (Tasks 4-6) are less conclusive, most likely due to the short run times and the higher and broader range of flue gas temperatures. The short-term tests (Tasks 4-6) also had a smaller range of "carbon treat rates."

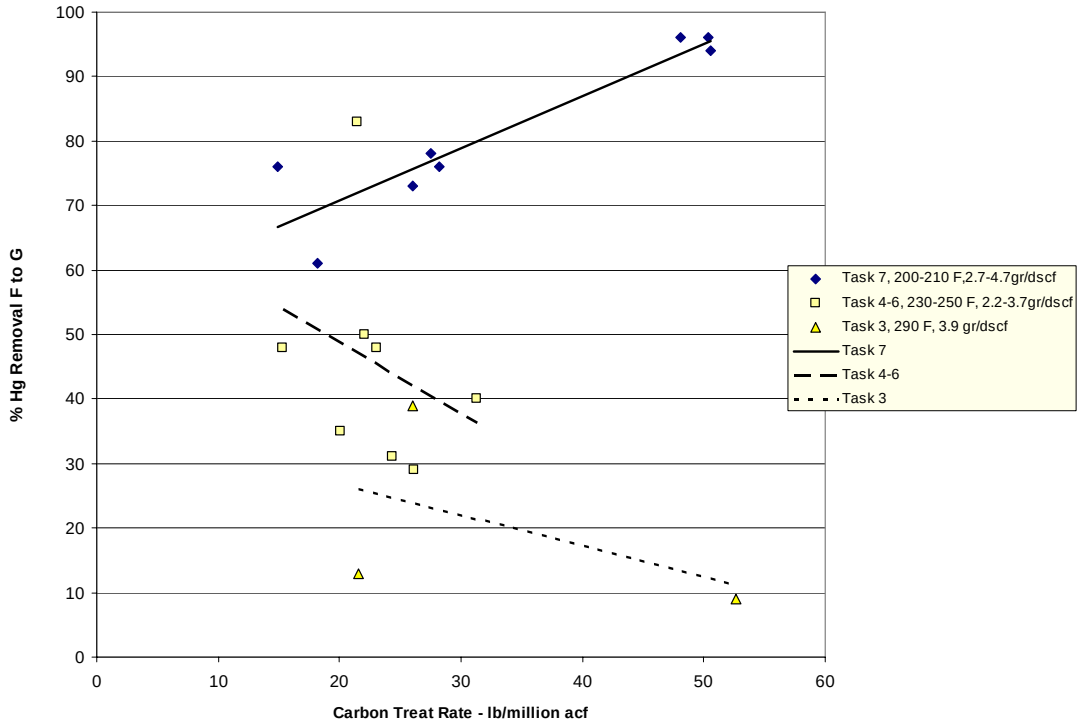


Figure 25. Mercury Removal from Pilot ESP Flue Gas at Various Carbon Treat Rates, lb/mmacf

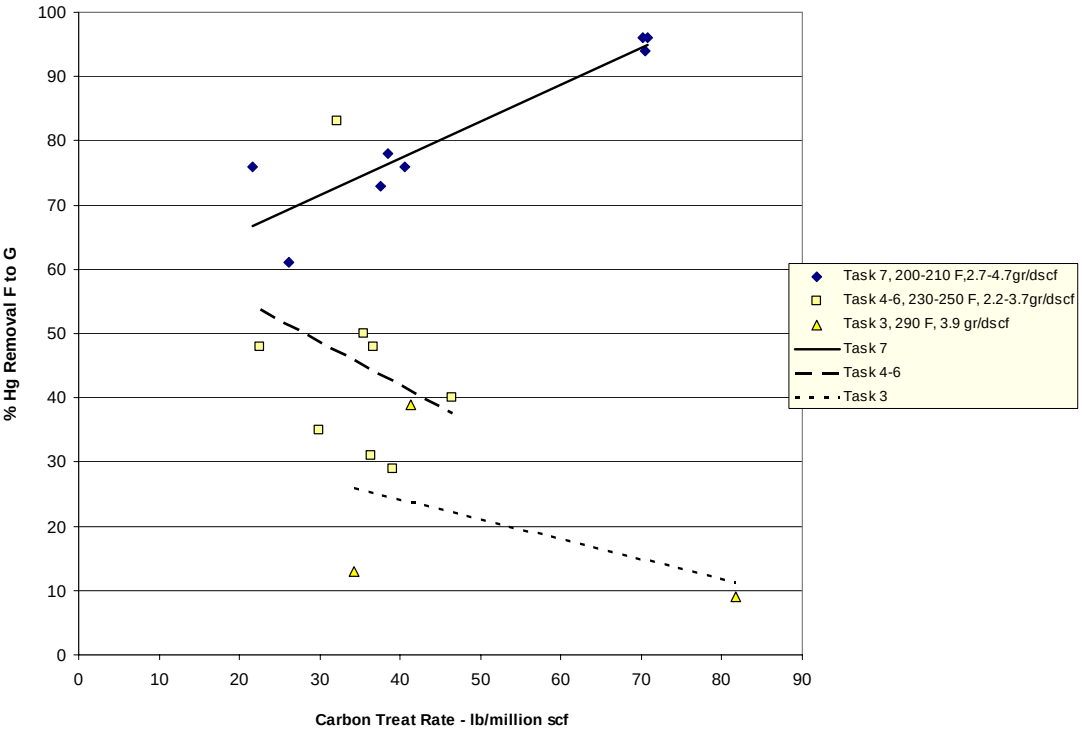


Figure 26. Mercury Removal from Pilot ESP Flue Gas at Various Carbon Treat Rates, lb/mmscf

Figure 27 shows flue gas particulate matter (fly ash) concentrations measured at the pilot ESP inlet (Location F) and theoretical concentrations based on the properties of the coal being burned in the host station. The theoretical concentrations are what would be expected in the actual power station. The theoretical particulate concentration calculations are summarized in section 7.6.2 of Appendix A. In Figure 27 the measured concentration of fly ash at the pilot ESP inlet is always less than the theoretical; this is not unexpected, since the slipstream extraction pipe occupies a very small portion of the host station duct.

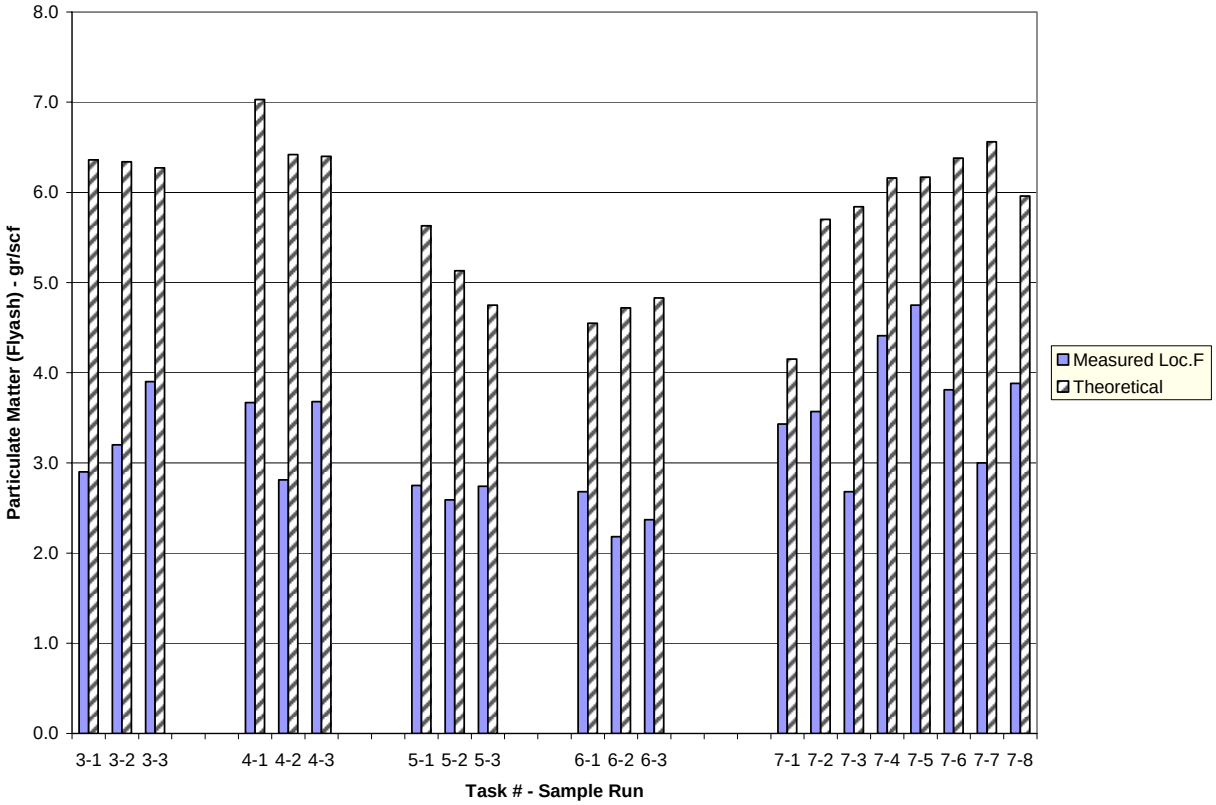


Figure 27. Flue Gas Particulate Matter (Fly Ash) Concentrations

Using the known carbon treat rates from the pilot plant and the calculated concentrations in the host plant flue gas of fly ash, a projected mercury removal versus percent carbon in the fly ash was plotted in Figure 28. This projects the mercury removal that could be achieved in the full-scale power plant. The calculated concentrations of fly ash and carbon in the host plant flue gas are shown in Appendix A.

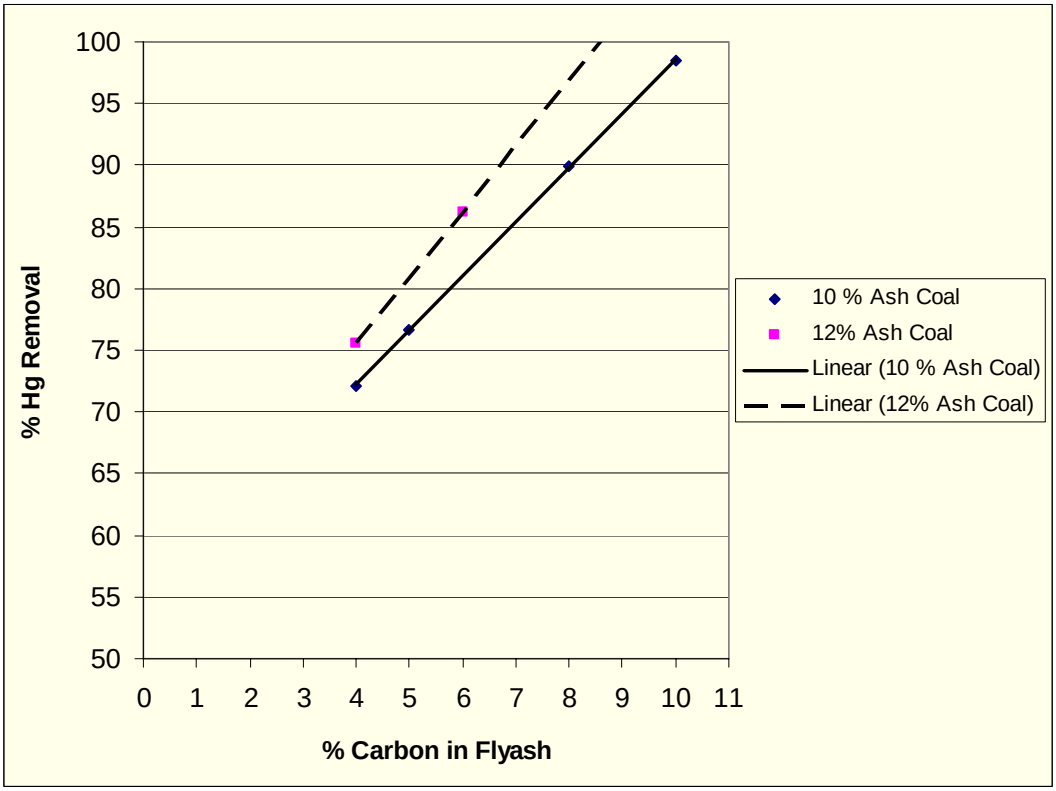


Figure 28. Projected Mercury Removal versus Percent Carbon in the Fly ash with 200 °F Flue Gas

Mercury Speciation

A description of the pilot plant conditions and speciation measurement results is listed in Table 5 and they are further described in Appendix A. Table 9 summarizes the mercury speciation results obtained from the Ontario Hydro sampling method for flue gas sampled at the pilot ESP inlet (Location F) and the pilot ESP outlet (Location G) at the baseline conditions (Task 3). The data suggest that, at the baseline condition, there may be a small apparent conversion of particulate mercury to elemental and ionic mercury as the flue gas traverses the ESP.

Table 10 shows the mercury speciation results obtained from the Ontario-Hydro sampling method for flue gas sampled at the pilot ESP inlet (Location F) and the pilot ESP outlet (Location G) at the deep air-heater cooling condition during parametric testing (Task 5). At these conditions, the data taken at face value indicate a great depletion of particulate mercury and a corresponding increase in elemental and ionic mercury as the flue gas traverses the ESP. Our interpretation is that, at the high-dust-loading and cool conditions at the ESP inlet, some of the elemental and ionic mercury in the flue gas condenses on the particulate matter in the thimble filter at the tip of the sampling probe artificially increasing the measured concentration of particulate mercury at the ESP inlet. Thus, these results strongly suggest that the Ontario-Hydro Mercury Speciation Method may not be valid for conditions with high dust loading and temperatures of 250 °F and below. This would not invalidate the total mercury result at these conditions, only the speciation results.

Table 9. Mercury Speciation via Ontario Hydro Method at Baseline Conditions – No $Mg(OH)_2$, 290 °F (1/29/04)

	Mass Flow Rates, μg/s		% Change
	ESP Inlet (Location F)	ESP Outlet (Location G)	
Hg^o	0.55	0.70	27
Hg^{++}	2.2	2.7	19
Hg^{part}	1.1	0.0	-100
Hg^{tot}	3.9	3.4	-13
Hg in ESP Fly ash	-	0.99	NA
Sum	3.9	4.4	12

The ESP outlet gas contains virtually no particulate matter and, therefore, it is expected that those speciation results are meaningful. The analysis of the fly ash samples collected in a thimble filter included in the sampling train at the pilot ESP inlet (Location F) showed average mercury concentrations of 0.48 ppm during baseline conditions and 1.04 ppm during deep cooling conditions.

Table 10. Apparently Erroneous Mercury Speciation Results via Ontario Hydro Method at Deep Cooling Conditions – 3.5/1 $Mg(OH)_2$, AH to 220 °F (3/24/04)

	Mass Flow Rates, μg/s		% Change
	ESP Inlet (Location F)	ESP Outlet (Location G)	
Hg^o	0.16	0.74	363
Hg^{++}	0.68	1.6	131
Hg^{part}	3.6	0.02	-99
Hg^{tot}	4.5	2.3	-48
Hg in ESP Fly ash	-	1.5	NA
Sum	4.5	3.8	-15

The total mercury concentration in the flue gas entering the pilot ESP (Location F) is plotted versus temperature in Figure 29 for all of the instances in which Ontario Hydro sampling was done during Tasks 3-7. In all cases, the measured concentration varied between 10 and 15 ug/m^3 corrected to zero oxygen. In Figure 30 the measured concentration of mercury at the pilot ESP inlet is always less than the concentration calculated from the coal properties. This may result from the fact that the slipstream extraction pipe occupies a very small portion of the host station duct and does not extract a perfectly representative sample. The theoretical mercury concentration calculations are summarized in section 7.6.1 of Appendix A.

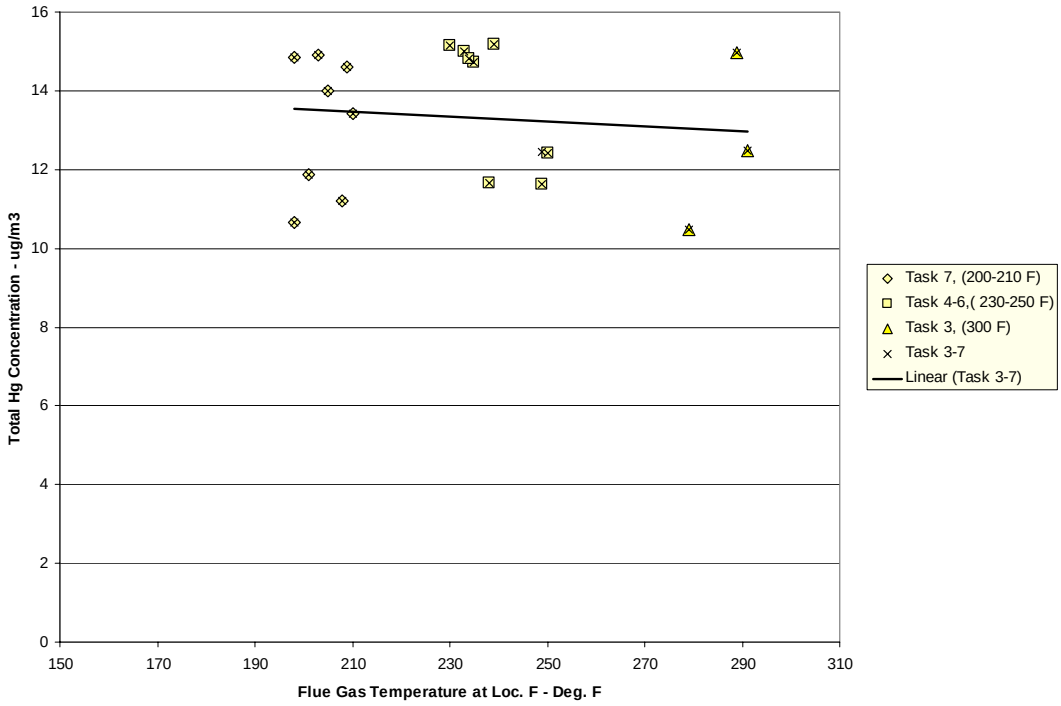


Figure 29. Total Mercury Concentration in the Flue Gas Entering the Pilot ESP Corrected to Zero Oxygen

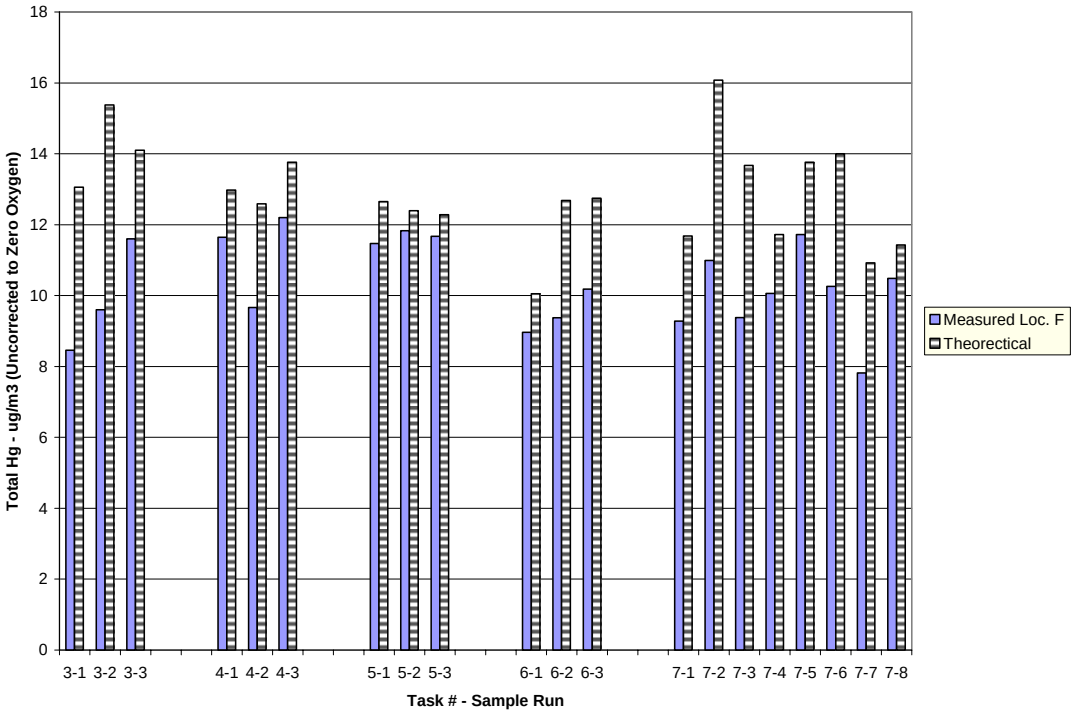


Figure 30. Measured and Theoretical Concentration of Mercury Entering the Pilot ESP

The reduction of elemental mercury at the pilot ESP outlet (Location G) as flue gas temperatures were lowered from 300 to 200 °F is shown in Figures 31 and 32. Figure 32 shows the effect of increased amounts of carbon in the fly ash on the reduction of elemental mercury. The reduction in temperature and increased carbon together effectively reduces the elemental mercury concentration to almost zero.

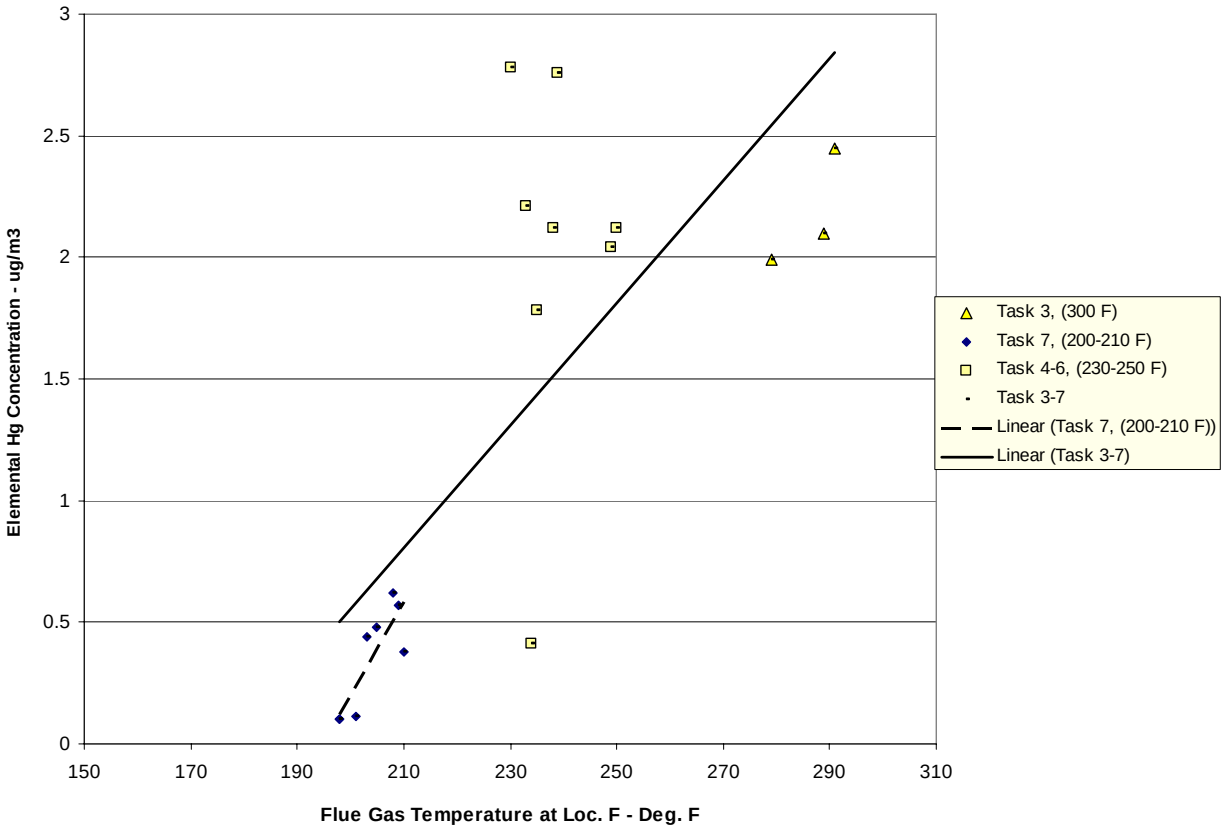


Figure 31. Reduction of Elemental Mercury at Lower Flue Gas Temperatures, Pilot ESP Outlet

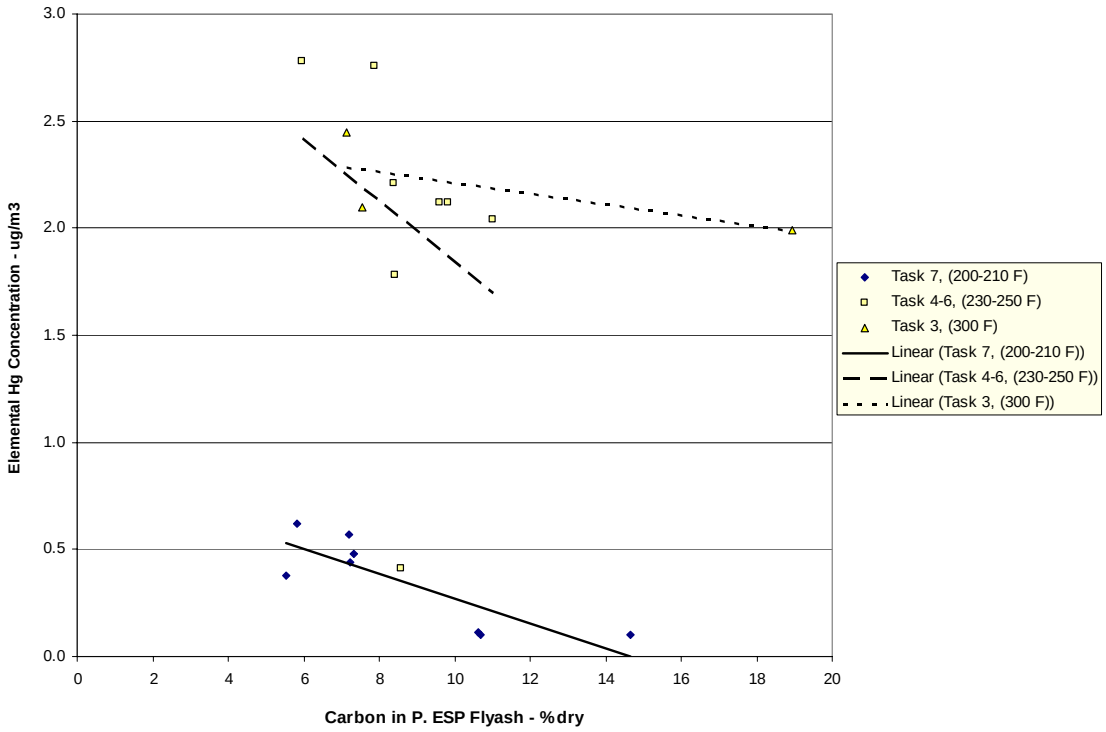


Figure 32. Effect of Carbon in Fly Ash on the Reduction of Elemental Mercury, Pilot ESP Outlet

The reduction of oxidized mercury at the pilot ESP outlet (Location G) as flue gas temperatures were lowered from 300 to 200 °F is shown in Figures 33 and 34. Figure 34 shows the effect of increased amounts of carbon in the fly ash on the reduction of oxidized mercury. The reduction in temperature and increased carbon together effectively reduces the oxidized mercury concentration to almost zero. The results of Figures 31-34 demonstrate that the LTMC process is efficient at removing both elemental and oxidized mercury.

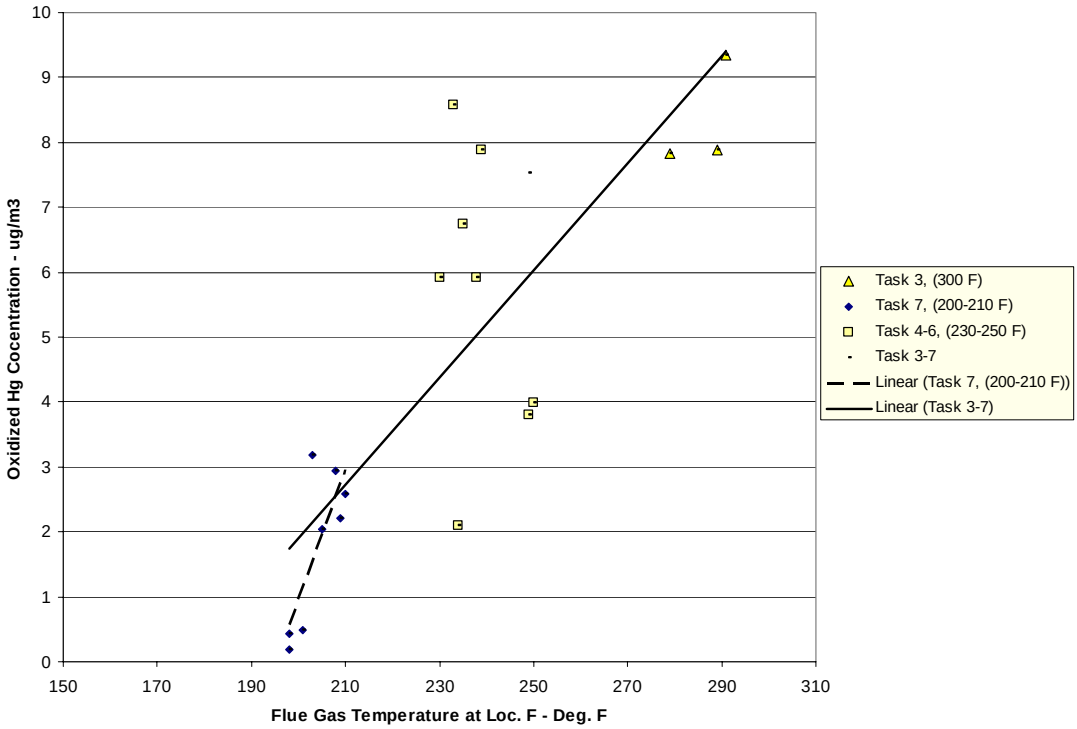


Figure 33. Reduction of Oxidized Mercury at Lower Flue Gas Temperatures, Pilot ESP Outlet

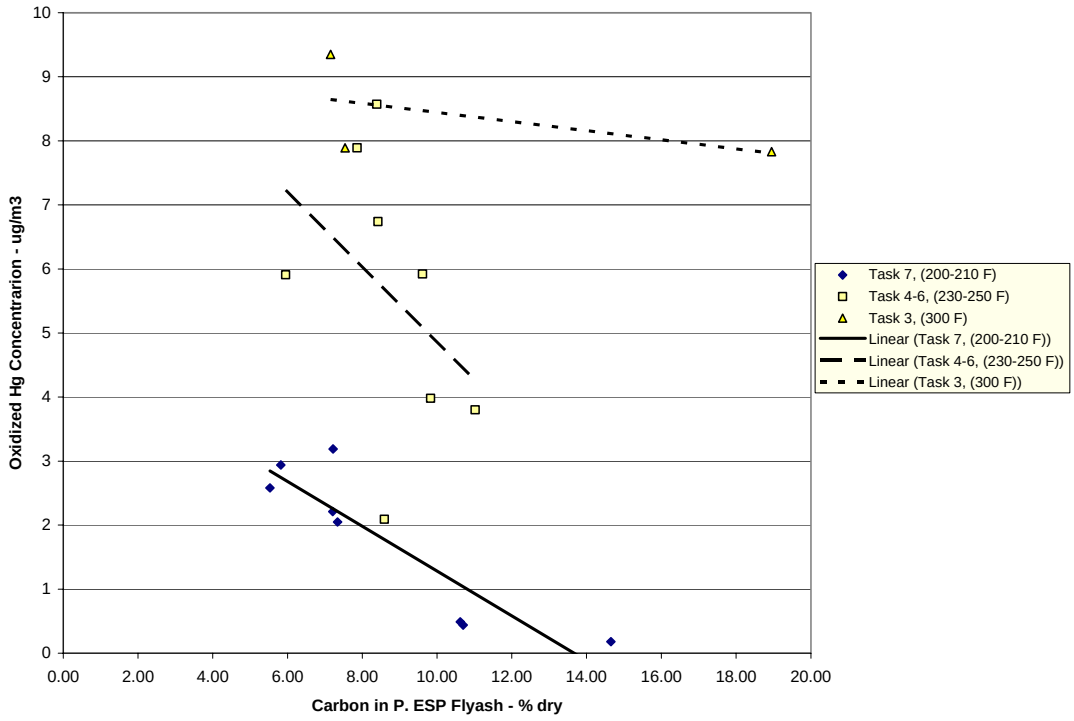


Figure 34. Effect of Carbon in Fly Ash on the Reduction of Oxidized Mercury, Pilot ESP Outlet

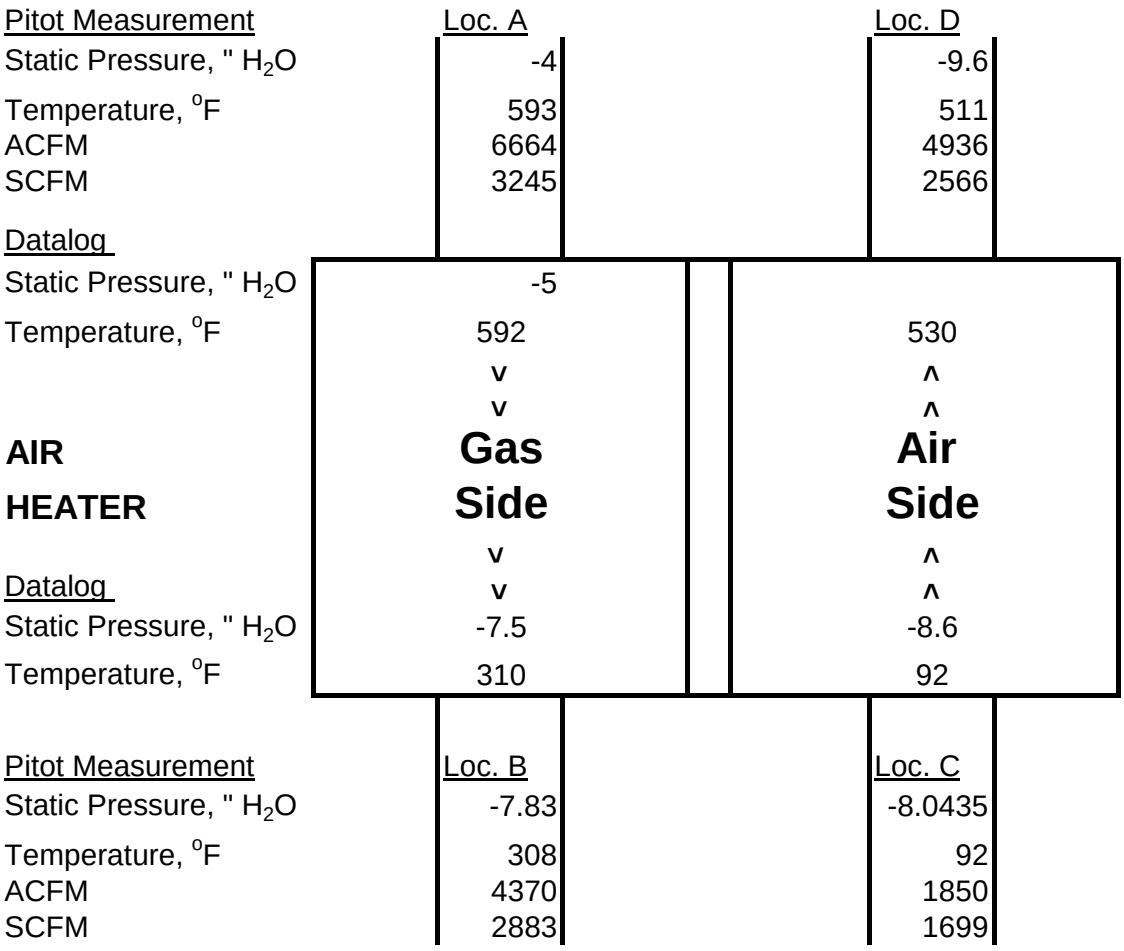
Pilot Air Heater Operation

Tables summarizing the pilot air heater operation during the entire test program (Tasks 3 through 7) are included in Appendix B (Tables B5, B6, B7). Alstom examined one pair of baskets removed from the pilot air heater on August 9, 2004, and one pair removed on January 5, 2005, which coincided with the beginning and end of long-term, low temperature testing (Task7). Alstom prepared a final test report which is included in Appendix D.

Flow Measurements

Air heater flow measurements were conducted on October 7, 2003, during the baseline tests (Task 3) and on March 3, 2004, at the start of low temperature testing (Tasks 4-7) with Mg(OH)2 injection. Figure 35 shows air heater flow measurements from October 7, 2003, and the flow balance. Figure 36 shows air heater flow measurements from March 3, 2004, and the flow balance. The flow balances of 0.9 to 1.1 are considered to be acceptable.

Test Date 10/07/03



Flow Balance: (Gas Out + Air Out) / (Gas In + Air In)

$$\frac{2883 + 2566}{3245 + 1699} = 1.10214$$

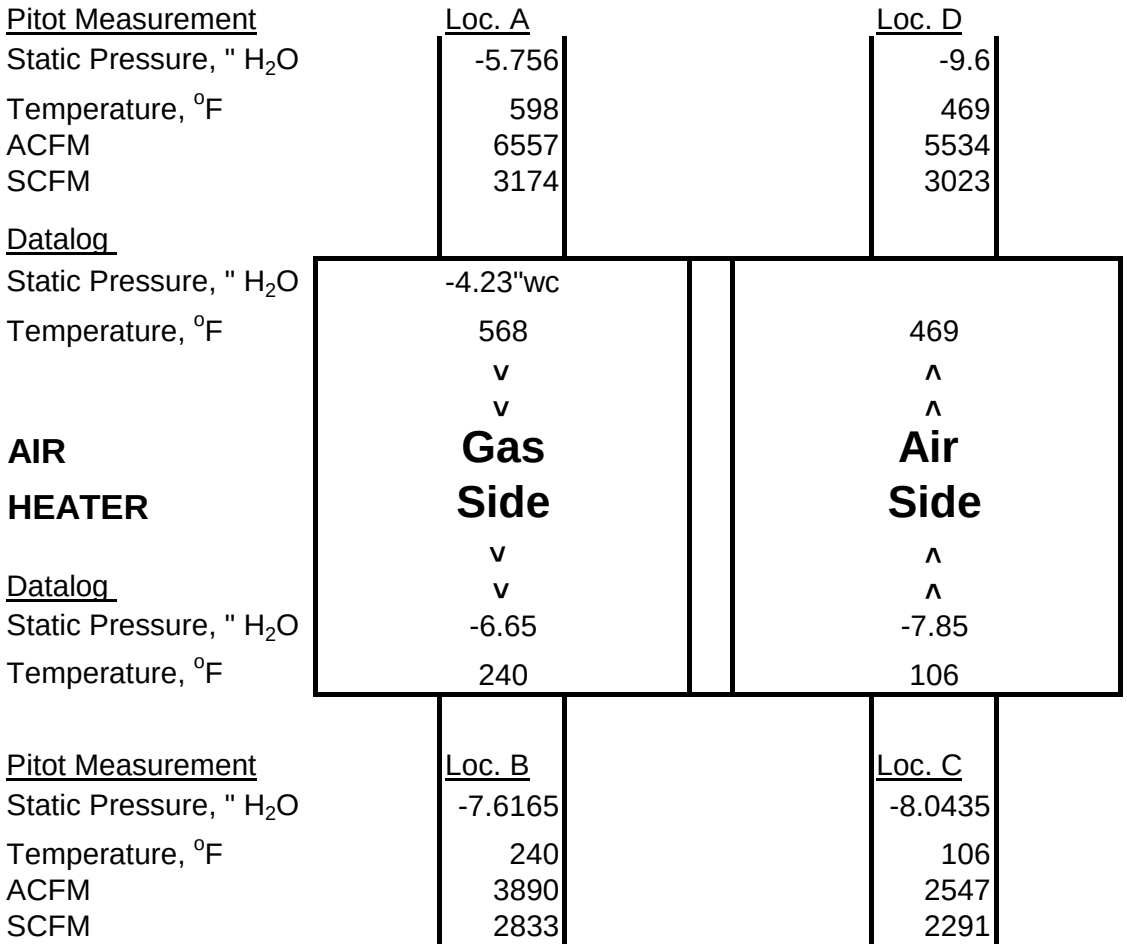
Gas Out - Gas In = -362 SCFM

Air Out - Air In = 867 SCFM

Estimated Air In-Leakage = 505 SCFM

Figure 35. Air Heater Flow Measurements 10/7/03

Test Date 03/03/04



Flow Balance: (Gas Out + Air Out) / (Gas In + Air In)

$$\frac{2833 + 3023}{3174 + 2291} = 1.07145$$

Gas Out - Gas In = -341 SCFM

Air Out - Air In = 732 SCFM

Estimated Air In-Leakage = 390 SCFM

Figure 36. Air Heater Flow Measurements 3/3/04

Data Logging

The following data points were logged by the computer control system into a database and stored for transfer via phone line. The data points were read every ten minutes during pilot plant operation.

- FIC-107 Dilute Slurry Mass Flow, Spray Nozzle
- DI-107 Dilute Slurry Density, Spray Nozzle
- FT-206 Extracted Flue Gas Mass Flow
- FT-222 Cooled Flue Gas/Air Heater Outlet Mass Flow
- FT-217 Air Heater Inlet Air Mass Flow
- TIT-205 Extracted Flue Gas Temperature
- TIT-223 Cooled Flue Gas/Air Heater Outlet Temperature
- TIT-215 Air Heater Inlet Air Temperature
- TIT-219 Air Heater Outlet Air Temperature
- PIT-227 Extracted Flue Gas Pressure
- DPIT-212 Air Heater Gas Side Diff. Pressure
- DPIT-216 Air Heater Cold End Diff. Pressure

Flue Gas Pressure Drop

The differential pressure across the flue gas side of the air heater was monitored throughout the test program to detect the presence of fouling of the metal heat transfer surfaces in the air heater. Monitoring was done through the control system data logger and at local pressure gages mounted at the air heater. Figure 37 shows no increase in differential pressure across the air heater flue gas side during a 74 hour long-term test run with no soot blowing. The spikes in differential pressure were due to startup, slurry injection nozzle cleaning and a short shut-down of the host station. The other variations are primarily due to changes in temperature at the flue gas inlet. An increase in gas temperature leads to an increase in differential pressure, since the gas has a higher volume at the higher temperature. A comparison of the gas inlet temperature, plotted in Figure 38, to the differential pressure in Figure 37 demonstrates that the minor changes in differential pressure resulted from the minor temperature changes (not fouling of the baskets) during the test run from December 7 to 10. The flue gas outlet temperature was quite constant during this same period (Figure 39).

Figure 40, a photo of the bottom of the cold end basket on the gas outlet of the air heater, shows a coating of fly ash on the plates after 74 hours. In Figure 41, the photo shows complete removal of the fly ash after soot blowing.

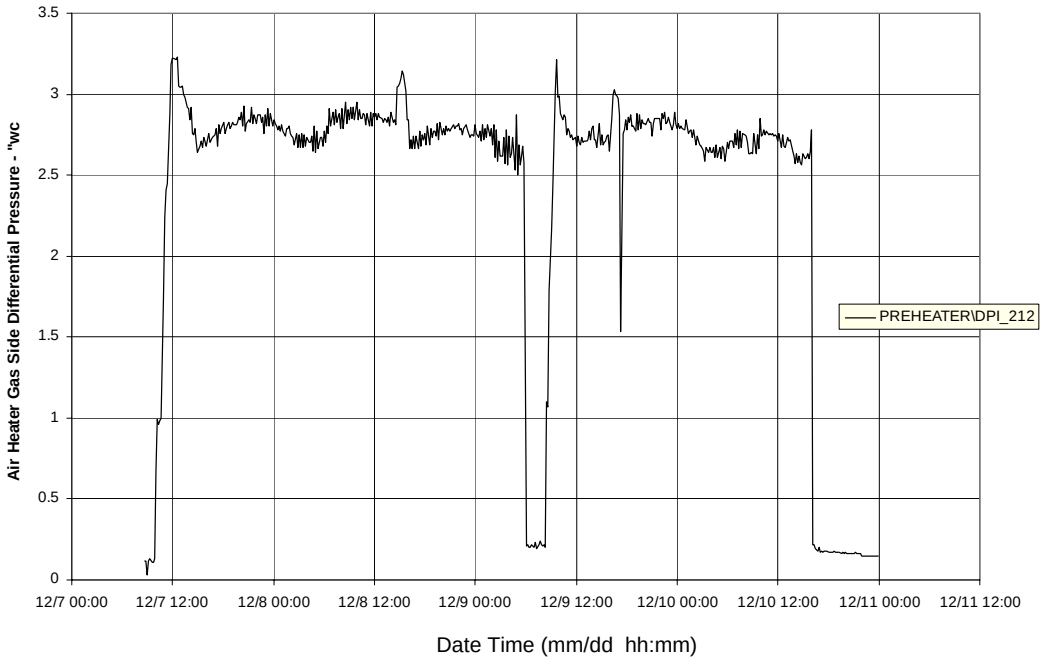


Figure 37. Differential Pressure during a 74 Hour Test Run with No Soot Blowing

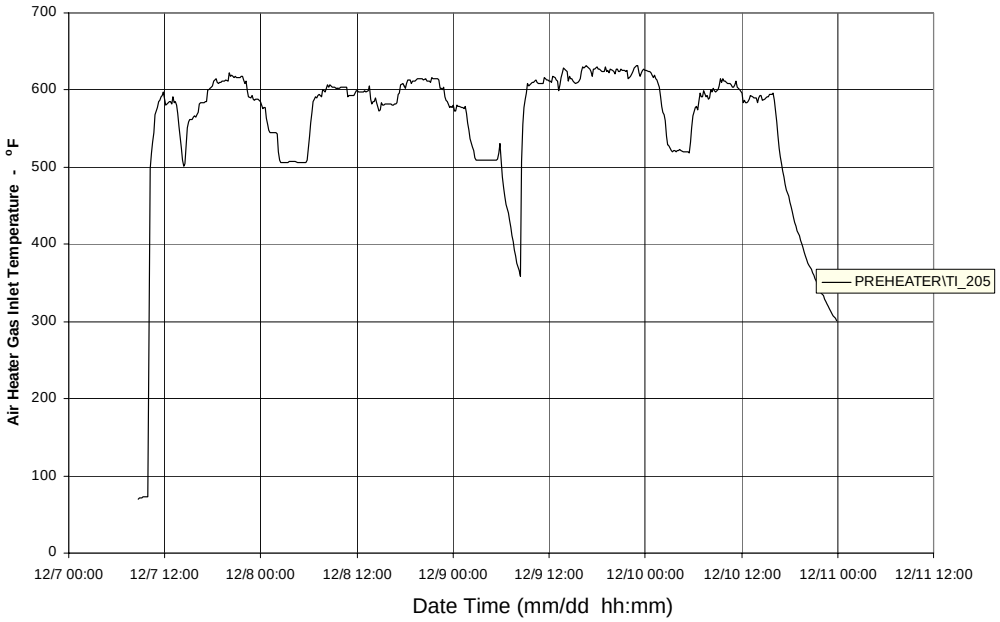


Figure 38. Gas Inlet Temperature during a 74 Hour Test Run with No Soot Blowing

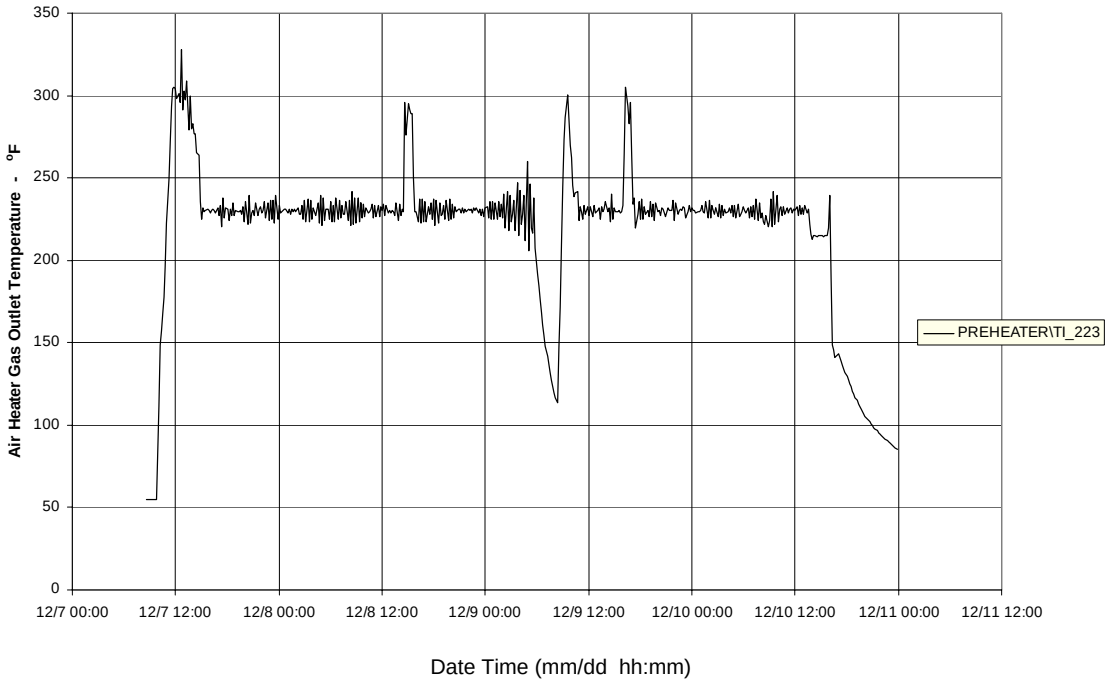


Figure 39. Gas Outlet Temperature during a 74 Hour Test Run with No Soot Blowing

Figure 40. Cold End Basket Before Soot Blowing

Figure 41. Cold End Basket After Soot Blowing

Figure 42 shows no increase in differential pressure across the air heater flue gas side during a second 75-hour long-term test run with no soot blowing. The spikes in differential pressure were due to startup and slurry injection inspection. The other variations are due to changes in temperature at the flue gas inlet or outlet. An increase in gas temperature leads to an increase in differential pressure, since the gas has a higher volume at the higher temperature. A comparison of the gas inlet temperature, plotted in Figure 43, and gas outlet temperature, plotted in Figure 44, to the differential pressure plotted in Figure 42, demonstrates that minor changes in differential pressure were caused by temperature changes (not fouling of the baskets) during the test run from December 14 to 17, 2004. On December 16 and 17, 2004, the air heater outlet temperature was raised to perform combination air heater and water spray cooling at the pilot ESP.

Figure 45, a photo of the bottom of the cold end basket on the gas outlet of the air heater shows a coating of fly ash on the plates after 75 hours. In Figures 46 and 47, the photos show complete removal of the fly ash after soot blowing.

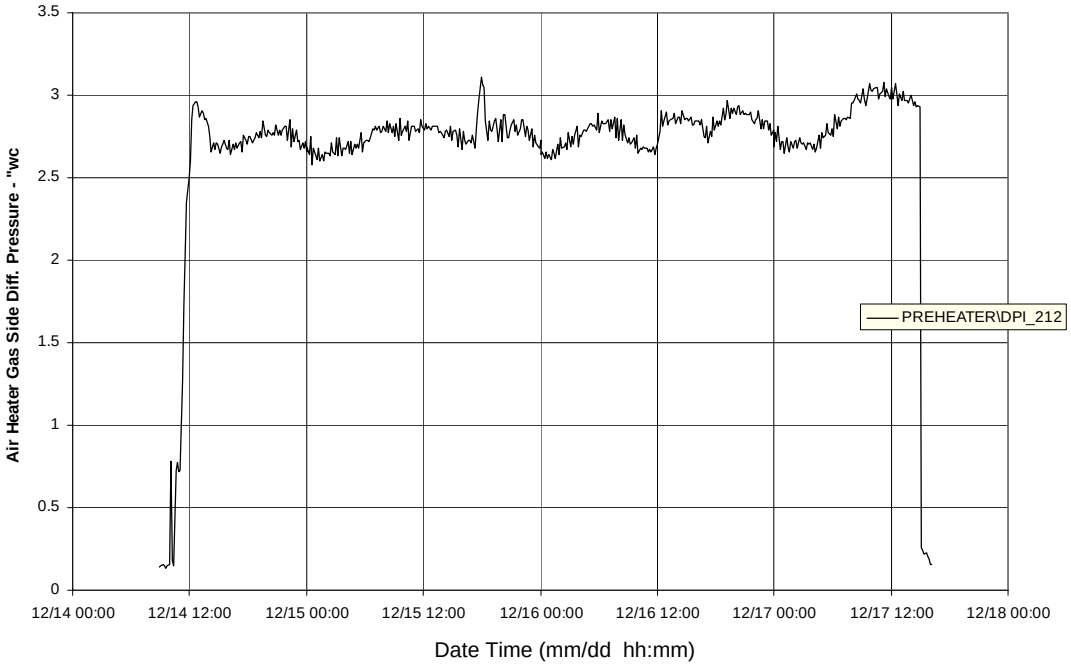


Figure 42. Differential Pressure during a Second 75 Hour Test Run with No Soot Blowing

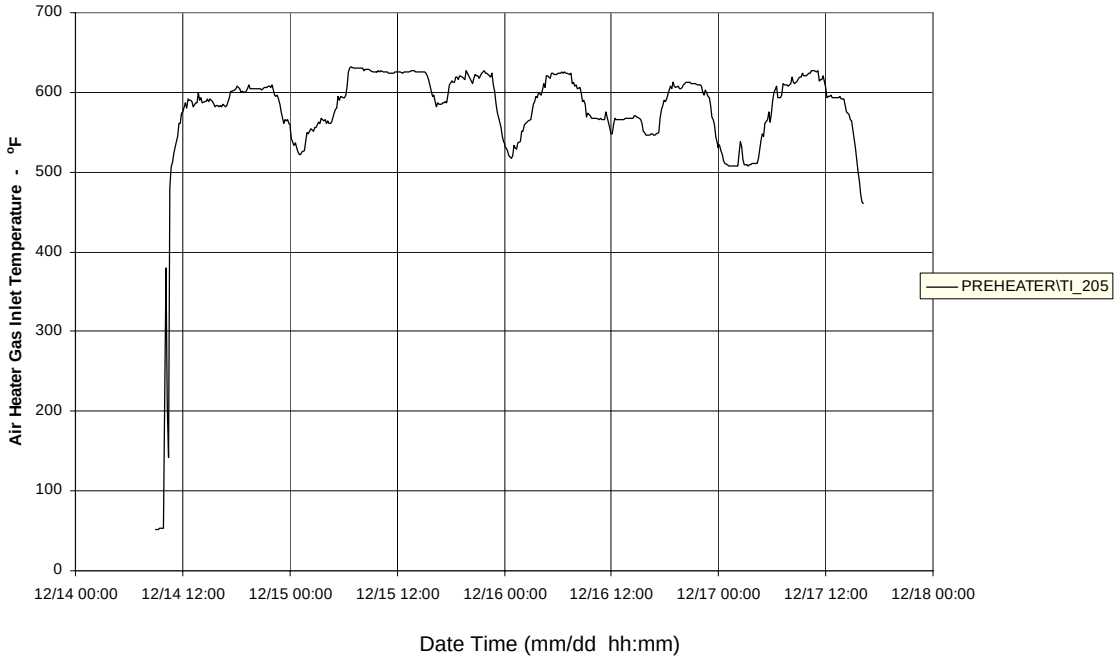


Figure 43. Gas Inlet Temperature during a Second 75 Hour Test Run with No Soot Blowing

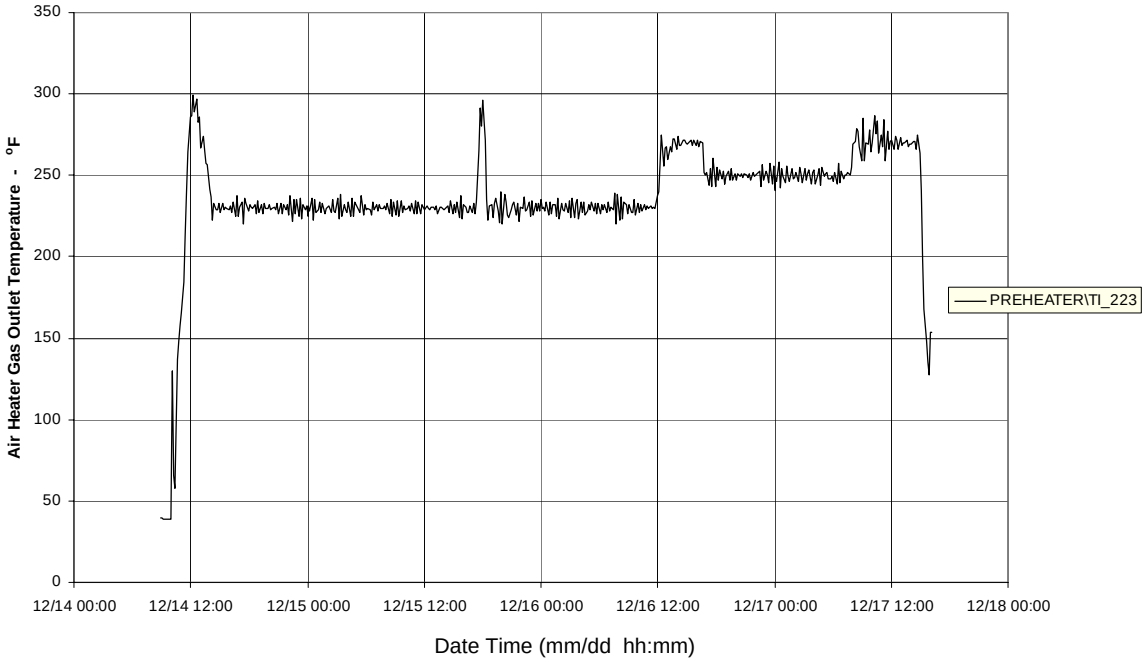


Figure 44. Gas Outlet Temperature during a Second 75 Hour Test Run with No Soot Blowing

Figure 45. Cold End Basket Before Soot Blowing

Figure 46. Cold End Basket After Soot Blowing

Figure 47. Cold End Basket After Soot Blowing

Pilot ESP Operation

Tables summarizing pilot ESP operation during the entire test program (Tasks 3 through 7) are included in Appendix B (Tables B5, B6, B7, B8). Details of pilot ESP operation are included in Appendix C. Figure 48 shows the collector plate area and spacing for each field of the pilot ESP. The pilot ESP has three fields with one rigid electrode and two collector plates per field.

Data Logging

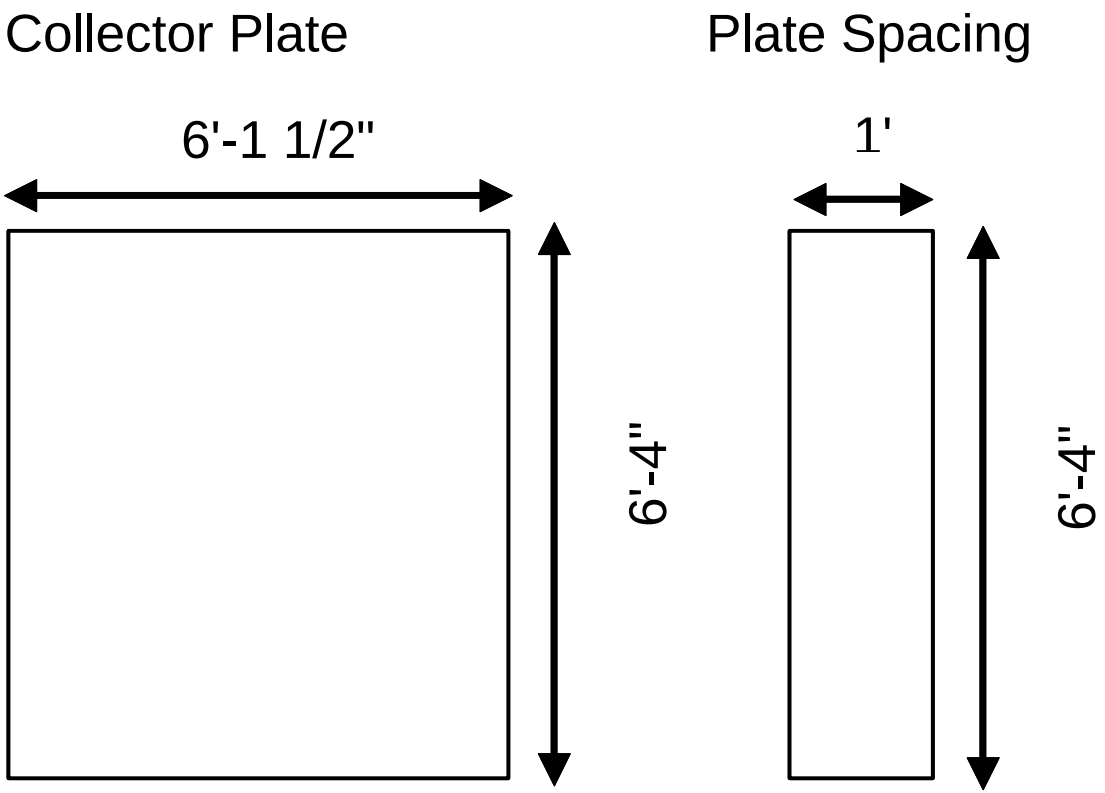
The following data points were logged by the computer control system into a database and stored for transfer via phone line. The data points were read every ten minutes during pilot plant operation at the pilot ESP.

- FT-302 ESP Inlet Mass Flow
- FT-309 Water Mass Flow, Spray Nozzle
- TIT-301 ESP Inlet, Upstream Temperature
- TIT-304 ESP Inlet, Downstream Temperature
- TIT-320 ESP Outlet Temperature
- TIT-306 Corrosion Probe Temperature
- PIT-319 ESP Inlet, Downstream Pressure

Voltage, spark rate and current flow to each of the operating fields were recorded manually at the transformer/rectifier controller screen mounted at the pilot ESP.

Performance

Table 11 contains a listing of the ESP performance data during the entire test program. In general the ESP was operated without the second field due to failure of the transformer/rectifier on field #2. The ESP was operated at specific collection area (SCA) of about 120 ft^2/1000 acfm, which is normal for a small pilot ESP. The pilot ESP gas velocity was about 3.4 ft/second. Typical ESP gas velocities[6] are in the range of 1.9-4.6 ft/second. Typical gas treatment times for utility ESPs are 8-30 seconds[6]; for the pilot ESP it was about 3 seconds. The $Mg(OH)_2$ injection and low temperature operation had no detrimental effect on the performance of the ESP, since particulate removal was 99+% for most test runs. Particulate removals below 99% were due to high-voltage insulation failures, which were related to the unique construction of the pilot ESP.



Collector Plate Area Per Field: 77.54 ft^2

Figure 48. Collector Plate Area and Spacing

Table 11. Pilot ESP Performance

Task-	Date	SCA*	Vol. Flow	Velocity	Treatment*	Inlet Temp	Removal	Part. Load*	Flyash*	Corona Power - watts / 1000 acfm		
OH Run	Sample Run	ft^2 / 1000 acfm	acfm	ft/s	seconds	deg F	%	Gr/DSCF	lb/hr	Field #1	Field #2	Field #3
3-1	12/17/03	130	1196	3.15	3.26	296(279)	99.7	2.89 / .009	19.9/.06	129	18	23
3-2	01/29/04	115	1350	3.55	2.89	291	99.4	3.20 / .016	24.7/.13	100	22	36
3-3	01/29/04	112	1380	3.63	2.82	295(290)	99.7	3.9 / .014	30.1/.11	100	22	36
AVG		119	1309	3.44	2.98	294	99.6					
4-1	02/24/04	122	1270	3.34	3.07	236(235)	99.4	3.67 / .022	28.3/.19	123	16	216
4-2	02/27/04	122	1273	3.35	3.06	237(238)	99.8	3.81 / .005	19.28/.19	9	18	217
4-3	03/01/04	122	1268	3.34	3.07	236(239)	99.6	3.68 / .015	25.24/.13	9	18	217
AVG		122	1270	3.34	3.07	236	99.6		Major T/R Controller Repairs Done			
5-1	03/24/04	127	1225	3.22	3.18	220(230)	98.9	2.75 / .030	18.86/.23	45		291
5-2	03/25/04	125	1236	3.25	3.15	233	93.8	2.59 / .158	17.79/1.22			315
5-3	03/25/04	128	1213	3.19	3.21	221(234)	95.6	2.74 / .121	18.18/.83			338
AVG		127	1225	3.22	3.18	224	96.1	T/R Controller Repairs & #1 Rapper Rod Replaced				
6-1	04/01/04	125	1241	3.27	3.14	240(249)	98.9	2.68 / .031	18.38/.21	660		729
6-2	04/13/04	130	1190	3.13	3.27	240(249)	99.5	2.18 / .008	14.93/.06	545		777
6-3	04/13/04	129	1204	3.17	3.24	250	99.6	2.37 / .014	16.24/.11	566		751
AVG		128	1212	3.19	3.21	243	99.3					
7-1	09/08/04	115	1345	3.54	2.90	219(198)	99.8	3.4 / .008	26.48/.07	165		518
7-2	09/09/04	121	1278	3.36	3.05	219(203)	99.5	3.58/.019	27.59/.15	175		605
7-3	09/09/04	121	1278	3.36	3.05	219(210)	99.5	2.68 / .013	20.69/.10	190		595
7-4	12/15/04	117	1323	3.48	2.94	215(201)	99.2	4.41/.030	37.83/.29	185		571
7-5	12/15/04	119	1299	3.42	3.00	215(198)	99.3	4.75/.027	36.67/.25	197		554
7-6	12/16/04	118	1309	3.44	2.98	215(205)	99.3	3.81/.021	29.40/.20	203		612
7-7	12/16/04	113	1370	3.61	2.84	215(208)	99.1	3.00/.023	25.76/.24	176		535
7-8	12/17/04	121	1279	3.37	3.05	215(209)	97.0	3.88/.098	29.97/.92	39		468
AVG		118	1310									
		** Based on 2 out of 3 fields operating*			** Based on 2 out of 3 fields*	Single Point (Average Sample Run) Temperature					* IN / OUT	* IN / OUT

ESP Operation

Tables listing voltages, spark rates and current flows to each of the operating fields are included in Appendix C. Drawings of the pilot ESP are included in Appendix C.

A number of high-voltage insulation failures occurred. The high voltage insulation failures were most often due to contamination from fly ash, and acid or moisture condensation. The fly ash and moisture contamination was reduced by the installation of a hot-air purge into the high-voltage compartment. The acid condensation failures were eliminated during $Mg(OH)_2$ injection. Figure 49 shows the almost-new condition of the rapper rod insulator after operation with $Mg(OH)_2$ injection during Task 6 through 7 (142 hours), which shows the effectiveness of SO_3 reduction by $Mg(OH)_2$ injection. Figure 50 shows a failed rapper rod insulator where the lower portion was blackened by acid condensation during operation without $Mg(OH)_2$ injection during Task 3. The acid gas was able to enter the high-voltage compartment through the unsealed edges and openings in the ¼" thick Teflon barrier between the flue gas and high-voltage compartments. Full-scale ESPs are better protected than the pilot ESP, and are more resistant to acid condensation.

Figure 49. High-Voltage Compartment with Rapper Rod Insulator in Foreground, Wall Bushing and Teflon Barrier in Background

Long-term operation (Task 7) at low temperature (210 °F) with humidification was not able to be conducted due to an electric short (arcing) through a fly ash deposit on the surface of a Teflon barrier. After approximately four hours of operation with water spray cooling the high voltage power supply was shut down when arcing was detected. The Teflon barrier collects fly ash (see Figure 17), which becomes more conductive as moisture is added to the flue gas entering the ESP during humidification. With air heater-only cooling, the Teflon barrier showed no signs of arcing even with a fly ash deposit on the surface of the barrier.

Figure 50. Failed High-Voltage Rapper Rod Insulator, Lower Portion Blackened by Acid Condensation

Mercury Stability Testing

Mercury Volatility Tests

The objective of this Task was to evaluate the stability toward volatilization of the adsorbed Hg on the ESP ash. Samples of pilot ESP ash taken during the baseline test, the short-term test program with humidification and the long-term test program, and a sample of the station ESP ash were selected for volatility testing. The sample matrix is shown in Table 12. Each fly ash sample was initially analyzed for concentrations of mercury, carbon,

moisture, and ash when received. Fifty grams of each fly ash sample was then placed in each of two 250 mL (8 oz) glass bottles. The two bottles of fly ash were held for 4-1/3 months in an oven at a temperature of 140 °F. Each bottle was equipped with a continuous Hg-free air purge, to prevent atmospheric Hg contamination of the samples (see Figure 51 and 52). Five-gram fly ash samples from each bottle were removed at 2-1/2 and 4-1/3 months and analyzed using ASTM Method D 6722, "Total Mercury in Coal and Coal Combustion Residues by Direct Combustion Analysis". Table 13 shows the data from the lab analysis of the fly ash samples.

Table 12. Sample Matrix for Hg Volatility Testing of ESP Fly Ash

Fly ash Sample Number	ESP Inlet Temp, °F	Humidification	$Mg(OH)_2$ Injection	Sample Number	Number of Tests
1	300	NO	NO	34	Duplicate
2	220	NO	YES	1P	Duplicate
3	240	YES	YES	76	Single
4	Station Fly Ash			64	Duplicate

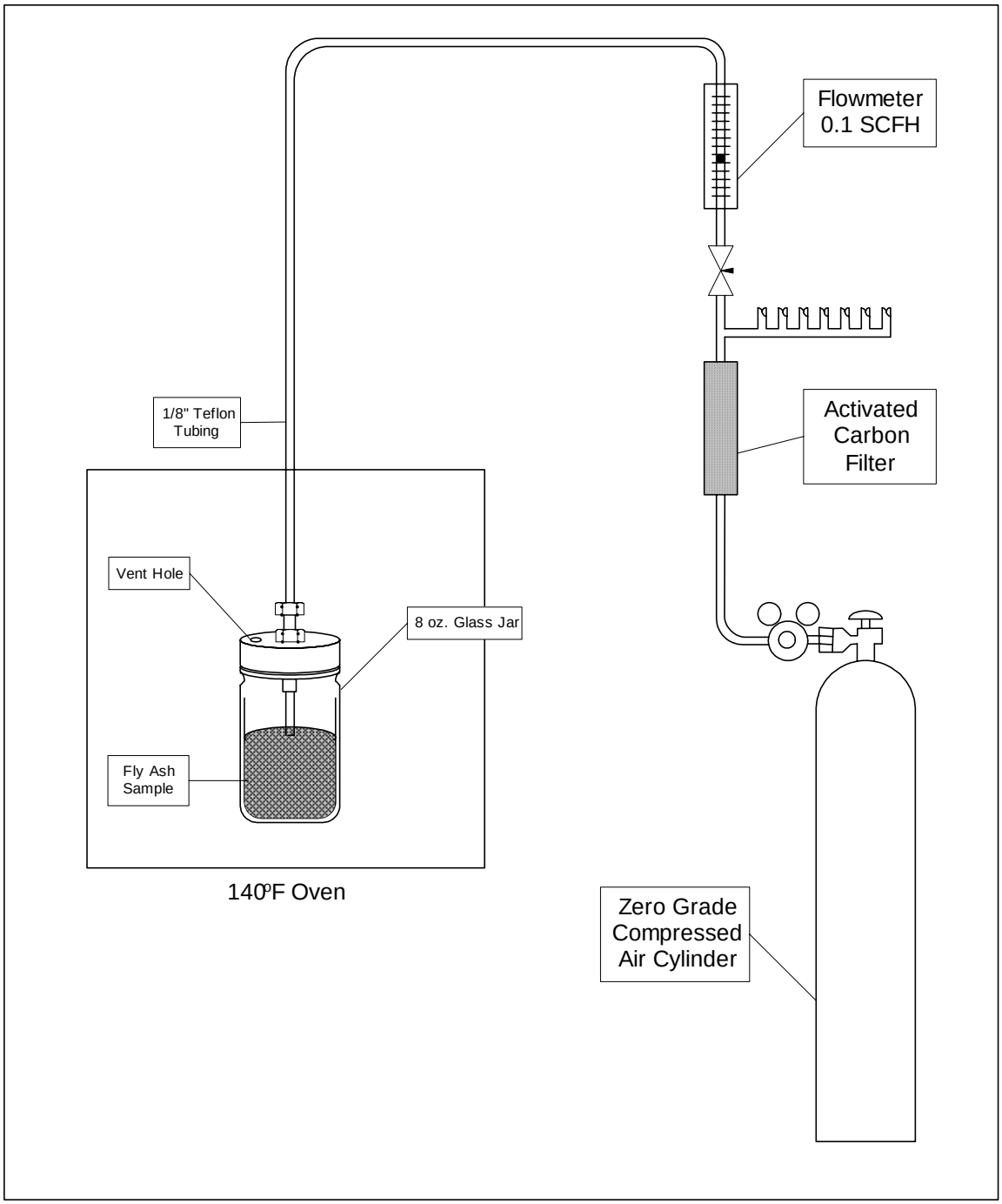


Figure 51. Volatilization Test Set Up

Figure 52. Mercury Volatility Fly Ash Samples in 140 °F Oven

Table 13. Volatilization Test Results

				SOLIDS ANALYSIS							
Analytical Number	Sample Number*	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	Hg dry basis	Ratio Hg test/initial	Hg avg	Average Ratio Hg test/initial
				%	(dry)%	(dry)%	ppm	ppm		ppm	
20045639	34-1-0	12/19/03	TASK 3 PILOT ESP	0.52	91.20	8.50	0.340	0.342			
20050839	34-1-1	2/10/05		0.24	91.29	8.70	0.348	0.349	1.021		
20051418	34-1-2	3/29/05		0.33	90.90	8.63	0.310	0.311	0.910	0.330	0.965
20045639	34-2-0	12/19/03	TASK 3 PILOT ESP	0.52	91.20	8.50	0.340	0.342			
20050840	34-2-1	2/10/05		0.22	91.25	9.15	0.330	0.331	0.968		
20051419	34-2-2	3/29/05		0.32	90.74	8.96	0.290	0.291	0.851	0.311	0.909
20051844	1P-3-0	5/4/05	TASK 7 PILOT ESP	1.67	91.72	7.06	1.200	1.220			
20050836	1P-3-1	2/10/05		0.30	91.40	7.03	1.090	1.093	0.896		
20051415	1P-3-2	3/29/05		0.84	89.97	7.17	1.280	1.291	1.058	1.192	0.977
20051844	1P-3-0	5/4/05	TASK 7 PILOT ESP	1.67	91.72	7.06	1.200	1.220			
20050837	1P-4-1	2/10/05		0.25	91.12	7.15	1.150	1.153	0.945		
20051416	1P-4-2	3/30/05		0.83	89.91	7.20	1.250	1.260	1.033	1.207	0.989
20051846	76-5-0	5/4/05	TASK 6 PILOT ESP	2.18	87.60	11.39	1.002	1.024			
20050838	76-5-1	2/10/05		0.19	87.69	11.06	0.963	0.965	0.942		
20051417	76-5-2	3/30/05		0.86	85.99	10.92	1.040	1.049	1.024	1.007	0.983
20051843	64-6-0	5/4/05	TASK 5 STAT ESP	0.52	88.93	10.33	0.296	0.298			
20050841	64-6-1	2/10/05		0.23	89.00	10.18	0.306	0.307	1.031		
20051413	64-6-2	3/30/05		0.46	88.82	10.01	0.260	0.261	0.878	0.284	0.954
20051843	64-6-0	5/4/05	TASK 5 STAT ESP	0.52	88.93	10.33	0.296	0.298			
20050842	64-7-1	2/10/05		0.18	89.07	9.87	0.311	0.312	1.047		
20051414	64-7-2	3/30/2005		0.51	88.8	10.05	0.29	0.291	0.980	0.302	1.013
										Average	0.970

* Fly ash Sample # - Jar # - Analysis #

Analysis #

0 - Initial Analysis - Start Date: 11/17/04
1 - Second Analysis - Date: 2/10/05
2 - Third Analysis - Date: 3/30/05

The test results are plotted in Figure 53. The concentration of mercury on each sample initially measured (Analysis #0) and measured again after 2-1/2 months (Analysis #1) and 4-1/3 months (Analysis #2) is shown by the bars for each jar in Figure 53. The mercury (Hg) concentration ratio of test result after 2-1/2 and 4-1/3 month periods divided by the initial Hg concentration is shown by the squares for each jar in Figure 53. The average of the Hg ratios for each pair of jars is show by the triangles.

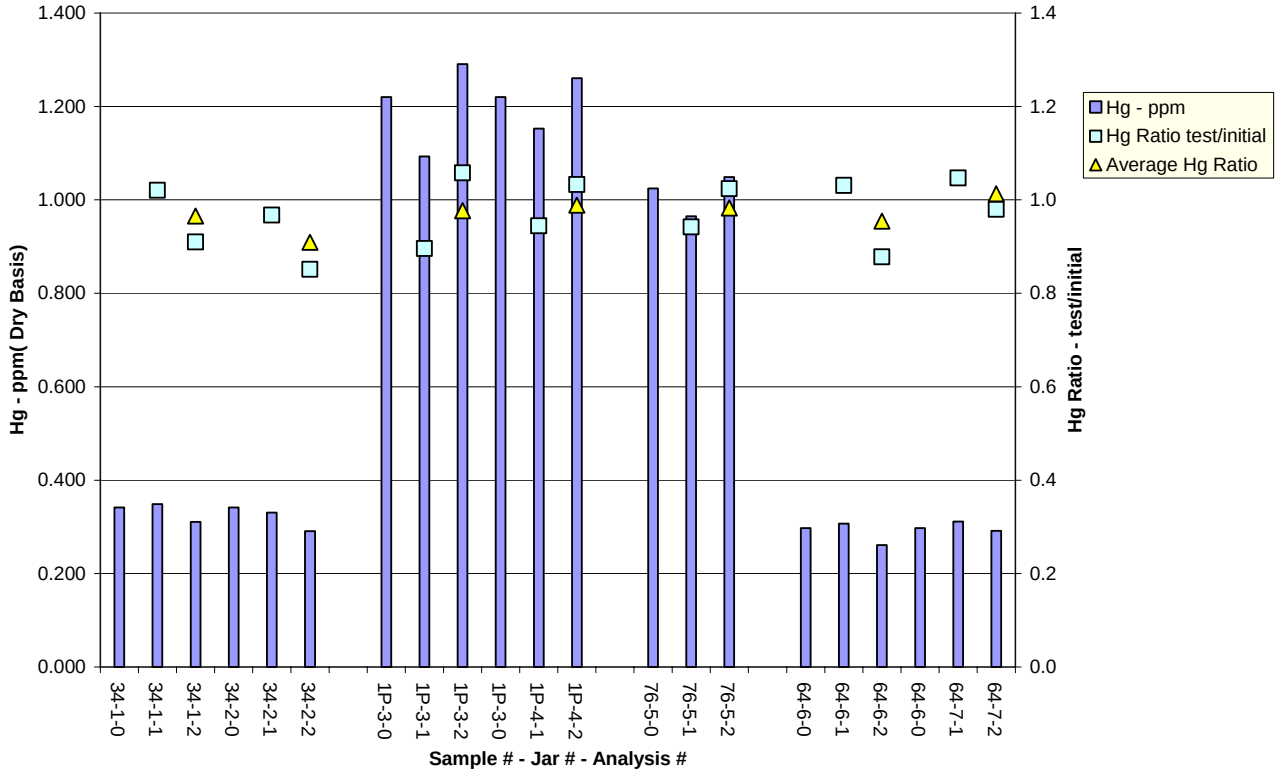


Figure 53. Mercury Volatility Test Results

After the 2-1/2 and 4-1/3 month period, one sample had an increased mercury concentration of 1.3%; other samples showed a decrease in mercury concentration of 1% - 9%. Fly ash samples with low concentrations of mercury initially tended to show increased mercury concentrations after 2-1/2 months, but considerable reductions at 4-1/3 months. Fly ash samples with high concentrations of mercury initially tended to show decreased mercury concentrations after 2-1/2 months, but considerable increases at 4-1/3 months. The variability in the data may be due to the method of mixing the 50-gram sample in the glass bottle and the way the 1 to 5 gram grab samples were taken initially and after each time period. On average the changes in mercury concentrations are not considered to be significant.

Mercury Leaching Tests

The objective of this task is to evaluate the stability toward leaching of the adsorbed Hg on the ESP ash. Samples of pilot-plant ESP ash were taken from baseline test and during the test program (with and without humidification), and a sample of the station

ESP ash was also collected. The test matrix is shown in Table 14. Mercury was determined on the four samples, and the four samples were subjected to TCLP leaching test. The leaching tests were conducted at three pHs on each sample, and mercury was determined in the leachates and the unextracted solids resulting from the leaching tests. The lab analysis results of the tests are shown in Table 15.

The four samples were leached using three different solutions: a 2.8 pH buffered solution, a 4.9 pH buffered solution, and deionized (DI) water. Duplicate samples were leached for three of the four samples. There was insufficient material to duplicate the one sample. The mercury detection limit for the leachate solutions was 1.0 ng/mL (ppb). This detection limit would detect a mercury loss from the solid samples of 0.02 mg/kg. A value less than the detection limit indicate that less than 0.02 mg/kg mercury was leached from the solid sample. The mercury content of the solid samples before and after leaching is given in the tables. However, because some materials can lose mass through dissolution of soluble solids, and other materials can gain mass through hydration of salts, the comparison of the mercury content of the solids before and after leaching is not necessarily indicative of mercury loss or gain.

The test results are plotted in Figure 54. The concentration of mercury in the four fly ash samples was initially measured and is shown by the bars (Sample #-Initial) in Figure 54. Each fly ash sample was then divided into 3 or 6 portions and leached at three different pH factors. The concentration of mercury on each portion leached at three different pH factors is shown by the bars in Figure 54. The mercury (Hg) concentration ratio of test result divided by the initial Hg concentration is shown by the squares for each portion in Figure 54. The average of the Hg ratios at each pH is show by the triangles.

In Figure 54, samples 32 and 1P showed a typical variability with a maximum 6.6% increase in mercury and an 8.3% decrease in mercury. Samples 78 and 79 showed large increases in mercury of 5 to 35.5%. Some of this variability may be due to the mixing of the samples and the way the 1 to 5-gram grab samples were taken for each mercury analysis.

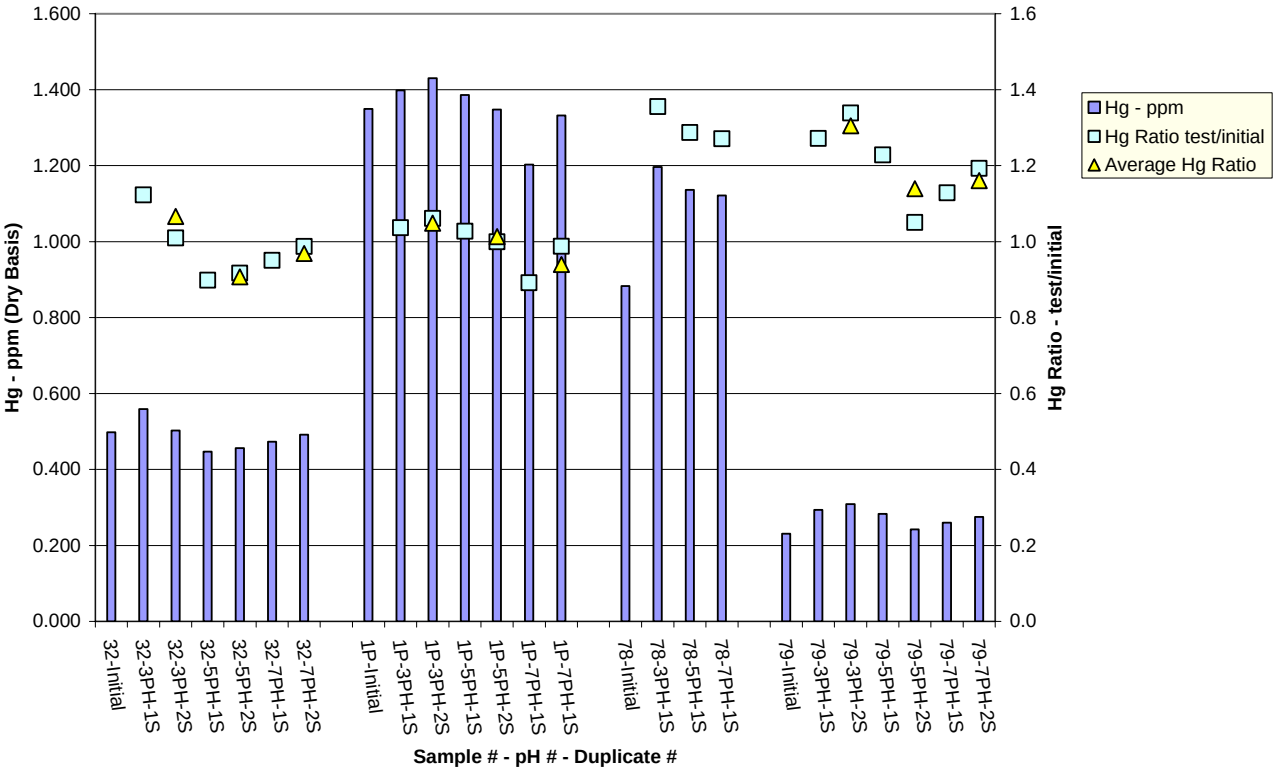


Figure 54. Mercury Leaching Test Results

Table 14. Sample Matrix for Hg Leaching Test of ESP Fly Ash

Fly ash Sample Number	ESP Inlet Temp, °F	Humidification	$Mg(OH)_2$ Injection	Sample Number	Number of EPA TCLP Tests (Weight for each test, 20 gm)		
					3 pH	5 pH	7 pH
1	320	NO	NO	32	Duplicate	Duplicate	Duplicate
2	220	NO	YES	1P	Duplicate	Duplicate	Duplicate
3	240	YES	YES	78	Single*	Single*	Single*
4	Station Fly Ash			79	Duplicate	Duplicate	Duplicate

* Weight for each test, 15 gm

Table 15. Leaching Fly Ash and Liquid Lab Analysis Results

				FLY ASH SOLIDS ANALYSIS								
Analytical Number	Sample Number*	Date	Description	As Det. Moisture	ASH	C	As Det. Hg	Hg - dry basis	Ratio Hg test/initial	Hg avg	Aerage Ratio Hg test/initial	Liquid Analysis Hg
				%	(dry)%	(dry)%	ppm	ppm		ppm		ng/ml
20051389	32-Initial	3/29/2005	TASK 3 PILOT ESP	0.96	91	8.92	0.493	0.498				
20051391	32-3PH-1S	3/29/2005		0.7			0.555	0.559	1.123			<1.0
20051394	32-3PH-2S	3/29/2005		0.7			0.499	0.503	1.010	0.531	1.066	<1.0
20051392	32-5PH-1S	3/29/2005		0.7			0.444	0.447	0.898			<1.0
20051395	32-5PH-2S	3/29/2005		0.28			0.455	0.456	0.917	0.452	0.907	<1.0
20051393	32-7PH-1S	3/29/2005		0.65			0.47	0.473	0.950			<1.0
20051396	32-7PH-2S	3/29/2005		0.28			0.49	0.491	0.987	0.482	0.969	<1.0
20051390	1P-Initial	3/29/2005	TASK 7 PILOT ESP	2.22	89.89	7.51	1.319	1.349				
20051397	1P-3PH-1S	3/29/2005		0.29			1.394	1.398	1.036			<1.0
20051400	1P-3PH-2S	3/29/2005		0.37			1.425	1.430	1.060	1.414	1.048	<1.0
20051398	1P-5PH-1S	3/29/2005		0.19			1.383	1.386	1.027			<1.0
20051401	1P-5PH-2S	3/29/2005		0.27			1.344	1.348	0.999	1.367	1.013	<1.0
20051399	1P-7PH-1S	3/29/2005		0.52			1.196	1.202	0.891			<1.0
20051402	1P-7PH-1S	3/29/2005		0.48			1.326	1.332	0.988	1.267	0.939	<1.0
20041860	78-Initial	4/13/2004	TASK 6 PILOT ESP	2.58	88.73	9.83	0.86	0.883				
20051403	78-3PH-1S	3/29/2005		0.29			1.193	1.196	1.355			<1.0
20051404	78-5PH-1S	3/29/2005		0.26			1.133	1.136	1.287			<1.0
20051405	78-7PH-1S	3/29/2005		0.5			1.116	1.122	1.271			<1.0
20041861	79-Initial	4/13/2004	TASK 6 STAT ESP	0.27	86.59	12.72	0.23	0.231				
20051406	79-3PH-1S	3/29/2005		0.4			0.292	0.293	1.271			<1.0
20051409	79-3PH-2S	3/29/2005		0.54			0.307	0.309	1.338	0.301	1.305	<1.0
20051407	79-5PH-1S	3/29/2005		0.44			0.282	0.283	1.228			<1.0
20051410	79-5PH-2S	3/29/2005		0.49			0.241	0.242	1.050	0.263	1.139	<1.0
20051408	79-7PH-1S	3/29/2005		0.47			0.259	0.260	1.128			<1.0
20051411	79-7PH-2S	3/29/2005		0.39			0.274	0.275	1.193	0.268	1.161	<1.0
								Average	1.096			

* Sample # - pH # - Duplicate #

Corrosion Study

In order to evaluate the corrosive effect of low-temperature flue gas operation on pilot plant components (duct work, air heater, ESP) a number of techniques were used to evaluate the corrosion potential. This included three in-duct corrosion coupons located at the outlet of the pilot ESP, a temperature-controlled corrosion probe located at the inlet of the pilot ESP and examination of pilot air heater baskets three different times during Tasks 3-7. The selection of coupons included metals normally used to build ductwork. The corrosion study of the coupons included a surface examination and lab analysis of deposits found on the coupons. The results of the examination of the air heater baskets are described in Appendix D.

The in-duct coupons consisting of three different metals (A36 carbon steel, Cor-Ten A, Cor-Ten B), at the pilot ESP outlet (Location G) were exposed to flue gas during the entire test program (Task 3 through 7). Each coupon consisted of a 1.25” diameter by 0.125” thick metal disk. The three coupons were mounted on a single threaded rod that held the coupons in the middle of the 10” pipe on the pilot ESP outlet. The temperature of the coupons was the same as the flue gas (200 to 300 °F) during test runs and 70 °F when the plant was shutdown. The coupons were removed for analysis in January 2005.

The temperature-controlled (150 °F) corrosion probe at the pilot ESP inlet (Location F) consisted of single A36 carbon steel coupon (coupon A36-#0) exposed to flue gas during Task 3 (300 °F flue gas) and then a second single A36 carbon steel coupon (coupon A36-#1) exposed to flue gas during Tasks 4 thru 7 (200-250 °F flue gas). Each coupon consisted of a 3” diameter by 0.125” thick metal disk mounted on a temperature-controlled probe that held the coupon on the side of the 10” pipe on the ESP inlet. See Figure B-14 in Appendix B for a detailed drawing of the probe. The probe temperature was set to 150 °F to be well below the flue gas temperature to simulate cold spots in the ductwork. Corrosion coupon A36-#0 was removed for analysis in February 2004. Corrosion coupon A36-#1 was removed for analysis in January 2005.

<u>Surface Examination</u>

The corrosion coupon surface examination procedure included photographing, weighing, and measuring the thickness of the coupons, and collection of fly ash and corrosion deposits. The surface examination results are shown in Table 16 and exposure times are shown in Table 17. A detailed description of operation and flue gas temperatures that the coupons were exposed to is listed in Table B-8 of Appendix B.

Table 16. Corrosion Coupon Surface Examination Results

Task	Coupon	Metal Temperature	Exposed Surface	Corrosion Deposit		Surface Thickness Swell					Weight Loss			Weight Loss Rate		
				Weigh	Concentration	Thk w/o Deposit	Initial Thk	Sides	Swell	Rate	Initial	End	Surface	Elapsed Time	Run Time	Elap. Rate
		°F	in^2	g	g/in^2	inch	inch		inch/side	inch/day	g	g	g/in^2	day	day	$g/in^2/day$
	In-Duct Metal Coupons in ESP Outlet															
3 thru 7	A36	70-290	2.233	0.010	0.004	0.1253	0.1240	2	0.0006	0.000002	17.326	17.322	0.002	429	50	0.00000
	Cor-Ten A	70-290	2.233	0.010	0.004	0.1124	0.1120	2	0.0002	0.000000	15.498	15.494	0.002	429	50	0.00000
	Cor-Ten B	70-290	2.233	0.014	0.006	0.1387	0.1380	2	0.0003	0.000001	19.187	19.179	0.003	429	50	0.00001
	Temperature Controlled Probe in ESP Inlet															
3	A36-#0	70-150	6.835	0.183	0.027	0.1234	0.1220	1	0.0014	0.000013	105.900	105.872	0.004	110	30	0.00004
4 thru 7	A36-#1	70-150	6.882	0.226	0.033	0.1250	0.1226	1	0.0024	0.000008	107.140	106.816	0.047	319	20	0.00015

Table 17. Corrosion Coupon Exposure Time

TASK	CORROSION COUPON	EXPOSURE TIME		Flue Gas Temperature °F	$Mg(OH)_2$ Injection
		Elapsed Time - hr	Run Time - hr		
3 thru 7	3-corrosion coupons in ESP Outlet	10296	1206	200-300	no/yes
3	150 °F Temperature-controlled probe coupon #0 in ESP Inlet	2640	709	300	no
4 thru 7	150 °F Temperature-controlled probe coupon #1 in ESP Inlet	7656	497	200-250	yes

The first step in the examination included removal of the fly ash deposit with a soft bristle brush and then, weighing the coupon. The coupon was then brushed with a wire brush to remove any corrosion deposit and then reweighed. The fly ash deposit and corrosion deposit were submitted for lab analysis. The wire brushed coupon thickness was measured. Early corrosion is characterized by swelling of the metal surface, longer term corrosion results in the loss of metal. All of our coupons swelled. A surface thickness swell rate was calculated based on the initial measured thickness. Figure 55 shows a swell rate comparison of the coupons from the pilot ESP outlet and the inlet. Coupons A36-#0 and A36-#1 from the temperature controlled probe at the inlet have higher swell rates, most likely due to the lower metal temperature. The swell rate appears to show that metal temperatures of 150 °F do increase the corrosion rate of A36 carbon steel, but an actual corrosion rate for surface thickness loss could not be determined because all of the coupons swelled. These results only show the beginning of the corrosion process, which often starts with the expansion of the metal surface before metal loss begins to occur.

Figure 56 shows a weight-loss rate comparison of the coupons from the pilot ESP outlet and the inlet. Coupons A36-#0 and A36-#1 (ESP inlet coupons) from the temperature-controlled probe at the inlet have higher rates than the ESP outlet coupons, most likely due to the lower metal temperature at the inlet. The higher surface thickness swell and lower weight loss rate of coupon A36-#0 relative to coupon A36-#1 may indicate that the scale was more difficult to remove or there was a difference deposit removal with the wire brush.

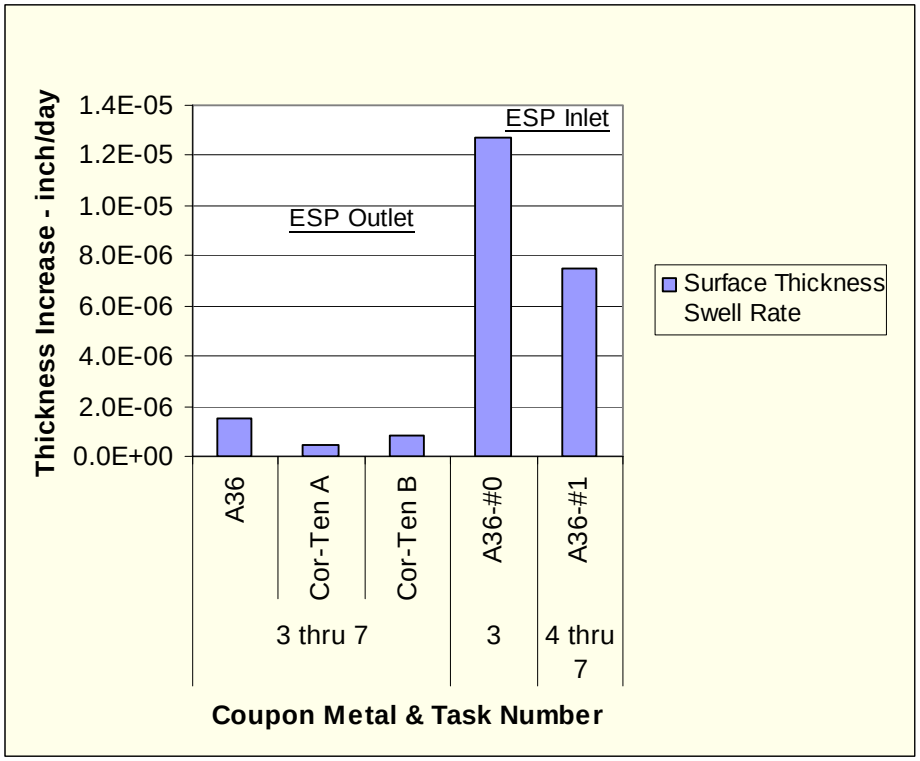


Figure 55. Corrosion Coupons, Surface Thickness Swell Rate Comparison

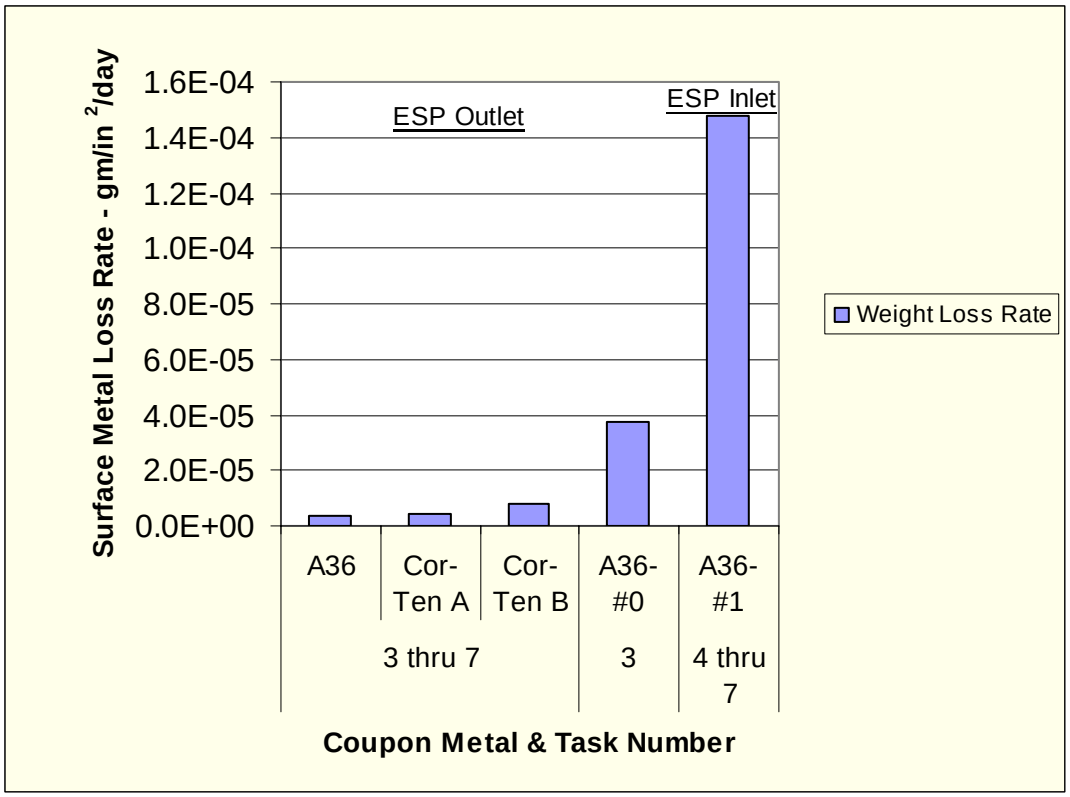


Figure 56. Corrosion Coupons, Weight Loss Rate Comparison

Deposit Analysis

The fly ash deposits were removed from the coupons with a soft bristle brush and submitted for lab analysis to determine moisture, carbon, mercury and various elements. The corrosion deposits were then removed with a stainless steel wire brush and submitted for similar lab analysis. Table 18 lists the lab analysis results of the fly ash deposits and corrosion deposits found on the coupons. Wire brushing of the three in-duct coupons in the pilot ESP outlet did not produce enough material to be submitted for analysis.

Table 18. Corrosion Study, Fly Ash and Corrosion Deposit Lab Analysis

							SOLIDS ANALYSIS												
Task Number	Coupon	Metal Temperature	Analytical Number	Date	Sample Number	Description	As Det. Moisture	C	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3	Undetermined
		°F					%	(dry)%	ppm	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%
	Three In-Duct Metal Coupons in ESP Outlet																		
In-Duct Task 3-7 ESP Out	A36	70-290	20051864	5/5/05	C-1	Flyash Deposit	0.00	4.08	0.766	40.54	19.77	0.97	16.21	4.60	1.56	0.59	1.63	0.53	7.32	6.28
	Cor-Ten A	70-290				Corrosion Deposits														
	Cor-Ten B	70-290				too Small to Analyze														
	Temperature Controlled Probe in ESP Inlet																		
Probe Task 3 ESP In	A36-#0	70-150	20051865	5/5/05	A36-HO-1	Flyash Deposit	0.00	3.73	1.630	18.31	7.89	0.39	41.38	1.79	0.34	0.20	0.64	0.13	10.39	18.54
			20051861	5/5/05	A36-HO-2	Corrosion Deposit	0.00	5.36	1.570	7.76	4.03	0.20	49.93	0.76	0.15	0.12	0.33	0.00	12.13	24.59
Probe Task 4-7 ESP In	A36-#1	70-150	20051862	5/5/05	A36-H1-1	Flyash Deposit	0.00	2.46	7.130	34.61	17.74	0.84	21.46	2.71	4.11	0.54	1.48	0.28	4.08	12.15
			20051863	5/5/05	A36-H1-2	Corrosion Deposit	0.00	0.99	0.676	3.96	2.03	0.10	67.63	0.32	1.20	0.08	0.18	0.00	2.86	21.64

Figure 57 shows a comparison of MgO measured in the fly ash and corrosion deposits found on the coupons. The temperature-controlled probe coupon exposed during Task 3 had the least amount of MgO, since no $Mg(OH)_2$ was injected during Task 3. The MgO in fly ash from the in-duct coupons was similar to the amount found on fly ash samples collected at the ESP inlet (Location F) and ESP hopper (Location I). The MgO in fly ash from the temperature-controlled probe during Tasks 4-7 is higher compared to the probe during Task 3 since $Mg(OH)_2$ was injected during Tasks 4-7.

Figure 58 shows a comparison of SO_3 measured in the fly ash and corrosion deposits found on the coupons. The temperature-controlled probe during Task 3 had the most SO_3 and this may be due to acid condensation, since no $Mg(OH)_2$ was injected during Task 3. The higher amount of SO_3 in the probe corrosion deposit during Task 3 seems to imply that acid condensation was occurring. The SO_3 in fly ash and corrosion deposits from the probe during Tasks 4-7 seems to show that $Mg(OH)_2$ injection was effective in removing SO_3 from the flue gas.

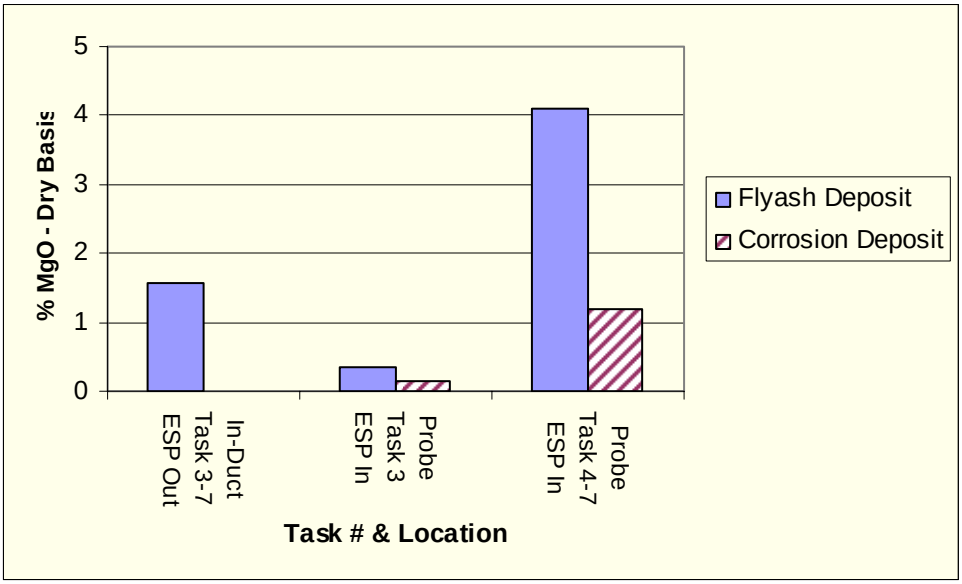


Figure 57. Comparison of MgO Measured in the Fly ash and Corrosion Deposits

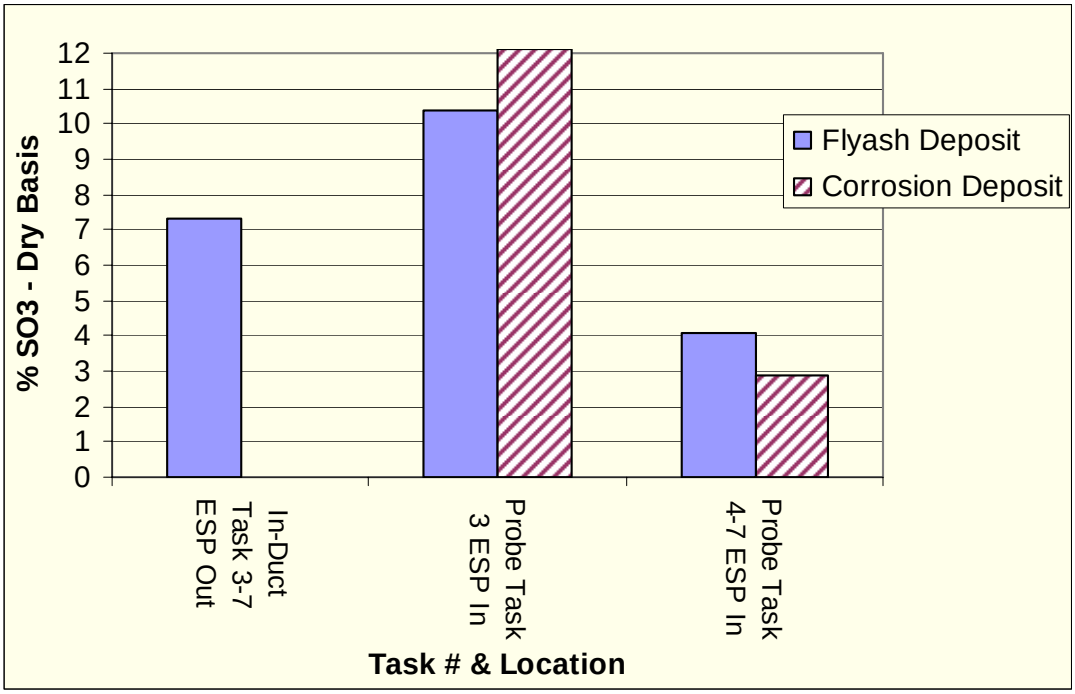


Figure 58. Comparison of SO_3 Measured in the Fly Ash and Corrosion Deposits

Mercury Absorption

Figure 59 shows the mercury measured in the fly ash and corrosion deposits found on the coupons. The temperature-controlled probe (150 °F) exposed during Task 3 has a small amount of mercury since flue gas temperatures were 300 °F during Task 3. The mercury in fly ash from the probe during Task 4-7 is very high, most likely due to the low flue gas temperature operation that occurred during these Tasks. This high mercury concentration is not due to carbon content since the carbon is the lower, as shown in Figure 60. This appears to show that fly ash deposits on cold surfaces adsorb mercury. This may be a further explanation for low mercury material balance closures at the pilot ESP that were observed only at low flue gas temperature conditions. The ESP inlet duct; outlet duct and hopper were not heated and coated with fly ash deposits that are not removed. Conditions on these surfaces are similar to the temperature-controlled probe.

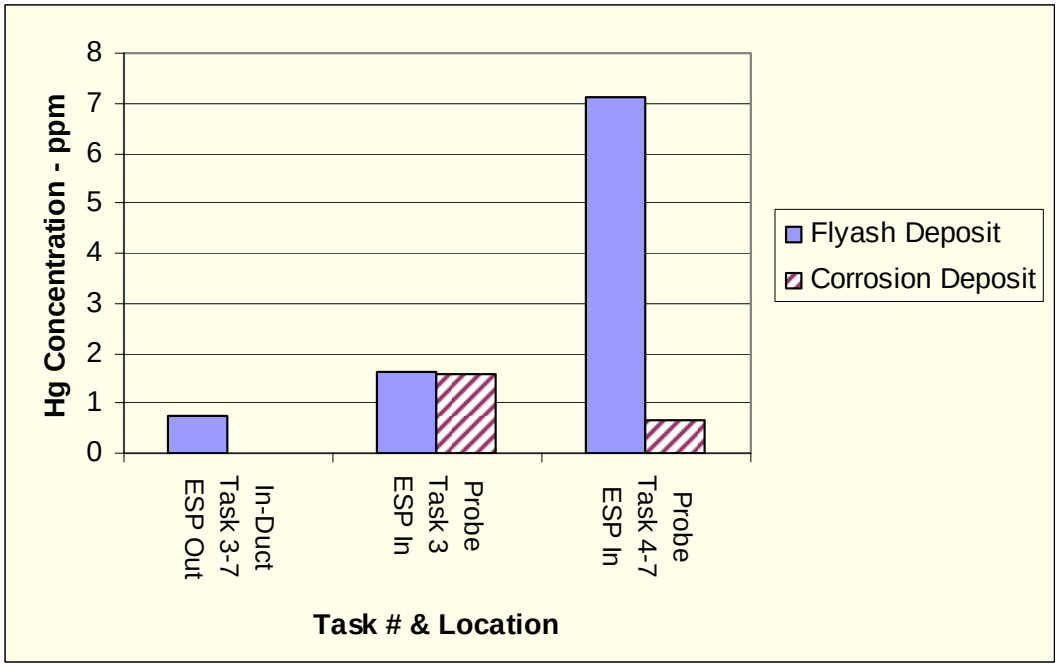


Figure 59. Comparison of Mercury Measured in the Fly Ash and Corrosion Deposits

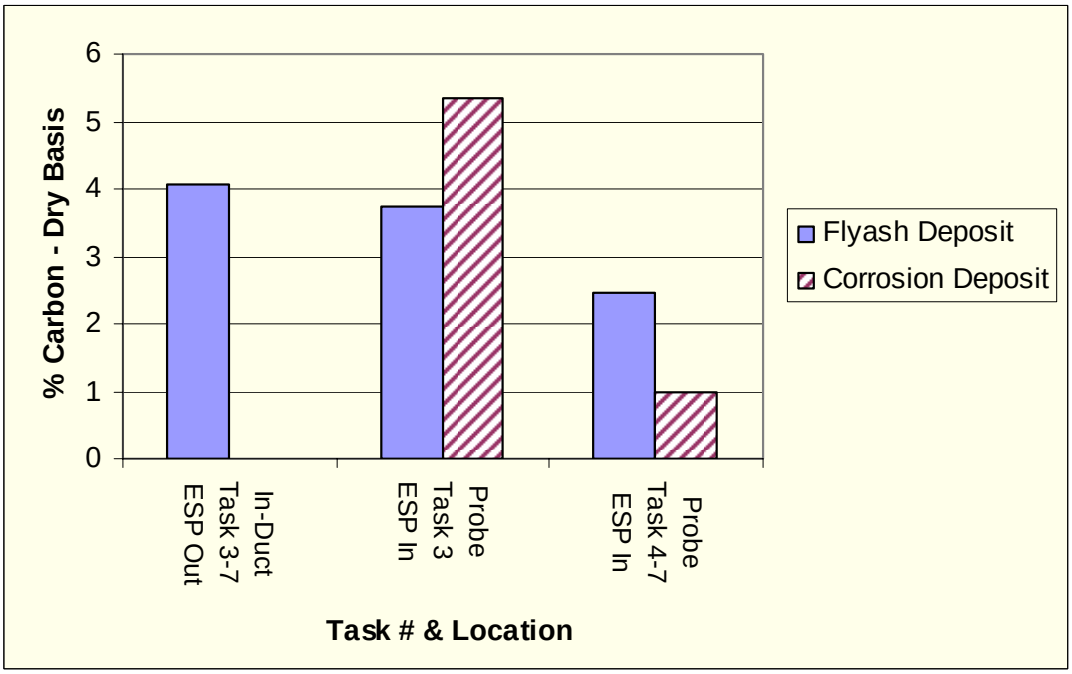


Figure 60. Comparison of Carbon Measured in the Fly Ash and Corrosion Deposits

Formal Presentations Resulting From This Project

This program resulted in eight separate formal presentations at national and international technical meetings. Those presentations are listed below, in reverse chronological order:

Winschel, R. A.; Fenger, M. L.; Payette, K. H.; Brickett, L. A. “Control of Mercury Emissions by Absorption on Fly Ash – Final Experimental Results of the CONSOL/Allegheny Pilot Plant Program” to be presented at the International Conference on Air Quality V, Mercury, Trace Elements, and Particulate Matter, Arlington, VA, September 19-21, 2005.

Winschel, R. A.; Fenger, M. L.; Payette “The CONSOL/Allegheny Pilot Plant Study of Low-Temperature Mercury Capture With an Electrostatic Precipitator” presented at the DOE/NETL Mercury Control Technology R&D Program Review Meeting, Pittsburgh, PA, July 14, 2005.

Winschel, R. A.; Fenger, M. L.; Payette, K. H.; Brickett, L. A. “Control of Mercury Emissions by Absorption on Fly Ash – Experimental Results of the CONSOL/Allegheny Pilot Plant Program” presented at the Power Plant Air Pollution Control “Mega” Symposium, Washington, DC, August 30 – September 2, 2004.

Winschel, R. A.; Fenger, M. L.; Payette “The CONSOL/Allegheny Pilot Plant Study of Low-Temperature Mercury Capture With an Electrostatic Precipitator” presented at the DOE/NETL Mercury Control Technology R&D Program Review Meeting, Pittsburgh, PA, July 14, 2004.

Winschel, R. A.; Fenger, M. L.; Banfield, T. L. “Control of Mercury Emissions by Absorption on Fly Ash –The CONSOL/Allegheny Pilot Plant Program” presented at the International Conference on Air Quality IV, Mercury, Trace Elements, and Particulate Matter, Arlington, VA, September 22-24, 2003.

Winschel, R. A.; Fenger “The CONSOL/Allegheny Pilot Plant Study of Low-Temperature Mercury Capture With an Electrostatic Precipitator” presented at the DOE/NETL Mercury Control Technology R&D Program Review Meeting, Pittsburgh, PA, August 12-13, 2003.

Winschel, R.A.; Fenger, M. L.; Statnick, R. M.; Banfield, T. L. “The CONSOL/Allegheny Mercury Control Pilot Plant Program” presented at the Nineteenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 25, 2002.

Winschel, R. A. “The CONSOL/Allegheny Multipollutant Emissions Control Pilot Plant Project for Reducing Hg, SO_2, and NO_x Emissions” presented at the Southeastern Electric Exchange Conference, Orlando, FL, June 20, 2002.

CONCLUSIONS

The following principal conclusions can be drawn from the test program: These conclusions are presented and discussed in two presentations given in July and September of 2005 and are included in Appendices E and F.

Sulfur Trioxide Control by Magnesium Hydroxide Injection

- $Mg(OH)_2$ slurry injection between the economizer and air heater is effective for removal of sulfur trioxide. This, in turn, prevents fouling of the air heater elements for test periods of up to 75 hours with no soot blowing during low temperature (225-230 °F) operation.
- Visible deposits on the cold-end air-heater elements were easily removed by soot blowing after test periods of up to 75 hours with no soot blowing during low temperature (225-230 °F) operation.
- Differential pressure measured across the flue gas side of the air heater did not increase due to fouling for test periods of up to 75 hours with no soot blowing during low temperature (225-230 °F) operation.
- A laboratory examination of air heater elements by Alstom Power did not indicate major corrosive activity on the element sheets, and the majority of the deposit could be removed with soot blowing. The baskets were removed after 291 hours of low temperature (230 °F) operation during Task 7 and after operating 24 hours with no soot blowing. Long-term operating results are difficult to predict from this data. The use of magnesium hydroxide injection appears to have conditioned the flue gas prior to the entry into the air heater such that rapid cold-end fouling or corrosion of the element did not occur.
- A molar ratio of 4:1 Mg/SO_3 effectively reduced air heater inlet flue gas SO_3 concentration to 3 ppmv or less, which was considered adequate to prevent air heater fouling.
- SO_3 reduction was further verified by significant reduction of SO_3 concentrations from 53 to 4.4 ppmv at the hot air outlet of the air heater.
- SO_3 reductions caused by $Mg(OH)_2$ slurry injection led to improved operation of the high-voltage rapper rod insulator in the pilot ESP by eliminating acid condensation on the surface of the insulator.
- Magnesium hydroxide injection resulted in reduced acid condensation in fly ash and corrosion deposits collected on the temperature-controlled corrosion probe at the pilot ESP inlet. SO_3 in the deposits went from 12% (no injection) to 3% (with injection).

Mercury Control

- 61 to 96% ESP mercury removal was demonstrated with cooling via air heater to 200-210 °F at the ESP inlet and fly ash carbon content of 6 to 15%. At baseline conditions, mercury removal was about 25%.

- Based on pilot plant results, a projected 90% mercury removal could be achieved in a full-scale plant by burning 10% ash coal with fly ash carbon (LOI) of 8% and 200 °F flue gas at the ESP inlet.
- Mercury removal with the ESP is improved with decreased ESP inlet temperature and higher unburned carbon content in the fly ash (LOI) will further increase mercury removal.
- Elemental Hg at the ESP outlet was reduced form 2.5 to 1.7 ug/m^3 as the carbon content of the fly ash went from 6 to 12 % during short term tests at intermediate flue gas temperatures of 230-250 °F.
- Elemental Hg was reduced from 0.5 to 0.1 ug/m^3 as the carbon content of the fly ash went from 6 to 14.5 % during long-term tests at low flue gas temperatures of 210-200 °F.
- Oxidized Hg at the ESP outlet was reduced from 8.5 to 2.0 ug/m^3 as the carbon content of the fly ash went from 6 to 12 % during short term tests at intermediate flue gas temperatures of 230-250 °F.
- Oxidized Hg was reduced from 3.2 to 0.2 ug/m^3 as the carbon content of the fly ash went from 6 to 14.5 % during long-term tests at low flue gas temperatures of 210-200 °F.
- The Ontario-Hydro mercury speciation method appears to suffer problems with high-dust streams at temperatures of less than or equal to 250 °F due to mercury absorption on fly ash collected in the sampling probe filter. Therefore mercury speciation could only be done at the ESP outlet.
- The pilot plant simulated host plant operation during baseline conditions. Pilot plant fly ash mercury versus carbon characteristics were equivalent to the host plant fly ash at baseline conditions. (Figure 11)
- The concentration of mercury on fly ash is directly related the carbon content (LOI) for a given flue gas temperature. (Figure 11)
- Lowering the flue gas temperature in the pilot plant increased the concentration of mercury on the fly ash over the baseline concentrations for the full range of carbon contents. (Figure 11, 12, 23)
- Lowering flue gas temperature in the pilot plant from 300 to 200 °F increased the mercury concentration in the fly ash for a constant amount of carbon. (Figure 20) Lowering flue gas temperatures in the host plant showed the same increase in mercury concentration in the fly ash for a fixed amount of carbon. (Figure 22)
- The mercury balance around the pilot ESP decreased from 120 to 60% as mercury removal increased from 20 to 96% indicating that mercury is accumulating in the ESP as removal increases. (Figure 6)
- High concentrations (higher than ESP hopper sample) of mercury were found on accumulated deposits of fly ash on the pilot ESP collector plates and Teflon barrier sheet indicating that mercury was being adsorbed. (Figure 18)
- A very high concentration of mercury was found in the fly ash deposit from the temperature-controlled corrosion probe coupon exposed during low temperature flue gas conditions (200-210 °F) indicating that mercury was being adsorbed by fly ash on low temperature surfaces. Only the two side walls of the pilot ESP are heated. The inlet, hopper and outlet of the ESP are unheated and would tend to collect mercury like the corrosion probe. (Figure 59)

Pilot ESP Operation

- Pilot ESP performance was not adversely affected by SO3 reductions and low temperature operation. Particulate removals of 99+% were achieved during all of the test conditions.
- Water spray cooling of the flue gas led to high voltage-insulation failures in the pilot ESP due to the unique arrangement of the insulation. Therefore, long-term tests with water spray cooling could not be completed.

Mercury Stability Tests

- Mercury volatility tests conducted for 4-1/3 months at 140 °F showed an overall average loss of 3% (Range +1.3 to –9%), in the mercury concentration in the fly ash for the four samples examined. This is not considered to be significant change.
- Mercury leaching tests conducted at pHs of 3, 5 and 7 showed an overall mercury concentration gain in the solids of 9.6% with a variation from +35.5 to -8.3%. It is presumed that the mercury concentration in the solids increased because of a loss of mass through dissolution of soluble salts.
- Mercury leaching tests conducted at pHs of 3, 5 and 7 showed no detectable amounts of mercury in the leachates.

Corrosion Coupons

- A rate of corrosion (metal thickness removal per year) was not able to be calculated during the test program since only the initial stages of corrosion were detected.
- Increased amounts of SO_3 due to acid condensation were found on the temperature-controlled probe held at 150 °F which could lead to increased corrosion activity. This occurred during the baseline tests with no magnesium hydroxide injection.

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APPENDIX A

Gas Sampling Program

J.E. Locke

1.0 Introduction

CONSOL Energy Research and Development (CONSOL) completed field sampling for Tasks 3, 4, 5, 6, and 7 (see Table A-1) of the Multi-Pollutant Emission Control Project, DOE Cooperative Agreement DE-FC26-01NT41181, at a slipstream pilot unit at Allegheny Energy's Mitchell Power Station.

Table A-1. Project Task Sampling Summary.

Task No.	Title	Process Activity	Sampling Parameters
3	Baseline Testing	Normal pilot plant operations.	SO_3, Hg, PM, PSD
4	Sorbent Evaluation	$Mg(OH)_2$ injection, various rates.	SO_3, Hg, PM, PSD
5	Parametric Testing	Deep flue gas cooling via air heater adjustments.	Hg, PM
6	Humidification Testing	Deep flue gas cooling via humidification adjustments.	Hg, PM
7	Long Term Evaluation	Operation using parameters selected from previous tasks.	SO_3, Hg, PM

Figure 1 provides an overview of the pilot plant, indicating the various components, gas flow, and sampling locations. The following sections detail the findings for each task.

2.0 Task 3 – Baseline Testing

2.1 Details

Sampling was conducted to determine the baseline levels for flue gas volumetric flow rates, sulfur trioxide (SO_3), mercury (Hg), total particulate matter (PM), and particle size distribution (PSD). Table A-2 outlines the sampling schedule.

Table A-2. Task 3 Sampling Matrix.

Date	Parameter	Location	No. of Tests
12/17/03	Hg	A, F, G	1
12/19/03	SO_3	A, F, G	2
1/20/04	SO_3	A, B, D	1
1/21/04	SO_3	A, D	2
		B	3
1/27/04	PSD	F, G	1
1/28/04	PSD	F, G	1
1/29/04	Hg	A, B, F, G	2

2.1.1. Pilot Plant Operations

No adjustments were made on the pilot plant for this task. The system was sampled while operating under standard operational conditions. Flue gas temperature was reduced to 300°F across the pilot plant air heater and the flue gas composition was not altered. However, the electrostatic precipitator (ESP) was operating at decreased efficiency due to decreasing ESP field voltages. Steps were taken to improve the voltages, however, no permanent solution was found during Task 3. The ESP voltages varied over the each sampling period, resulting in ESP efficiency variations of >99% to approximately 90%. Appendix B provides detailed information on pilot plant operations. During each sampling period samples were taken of the host plant coal, host plant ESP ash, and pilot plant ESP ash to determine a process mass balance.

2.1.2. Sampling

On December 17, 2003, CONSOL performed one mercury test at Locations A, F, and G. It was during this test that the ESP problems were first recognized. Following a maintenance day, CONSOL returned on December 19, 2003, to conduct SO_3 testing at these locations, as the ESP was still not operating satisfactorily.

No sampling was scheduled for the following four weeks to allow for further evaluations of the ESP and the sampling data already collected. During the data evaluation a substantial decrease in the SO_3 concentration between Locations A and F was noted. As a result the task was expanded to include SO_3 sampling at Location A and air heater Locations B and D to determine the source of the SO_3 loss. Subsequent baseline mercury sampling was also expanded to include sampling at Location B, in addition to Locations A, F, and G.

The air heater SO_3 sampling was conducted on January 19, 2004, the PSD sampling was conducted on January 27 and 28, 2004, and the remaining mercury tests were performed on January 29, 2004. Section 2.2 details the results of Task 3 sampling.

2.2 Results

2.2.1. SO_3 Sampling

All SO_3 sampling was performed using the controlled condensation sampling method. Each sampling run was conducted simultaneously at each location for a period of 40 minutes. While conducting Run 1 at the air heater gas-side outlet (Test B-AH-1), a crack developed in the sample train glassware, creating a leak that allowed the sample to become diluted with ambient air. An additional test run (Test B-AH-4) was conducted to provide three valid data points. The results are summarized in Table A-3.

Gas flow rate is not measured in the controlled condensation method. To calculate the SO_3 mass flow rates, the SO_3 concentrations at the ESP locations were multiplied by gas flow rates measured on December 17, while SO_3 concentrations at the air heater locations were multiplied by gas flow rates measured on October 7, 2003.

Locations A, B, F, and G are located in the process gas stream (Figure 1). Flue gas throughput at Location A is higher than at Location B because of gas leakage to the airside in the air heater between the locations. After Location B, a slipstream of the flue gas is routed to the pilot ESP. The pilot plant is designed such that gas flow rates at Locations F and G should be approximately one-third of that at Location B. The gas flow rate measured for these locations (Table A-3) show this to be accurate.

From measurements conducted on December 17, 2003, the gas flow at Location F, 768 DSCFM, was approximately one-fourth that measured at Location A, 3,004 DSCFM. However, on December 19, 2003, location F exhibited an SO_3 mass flow rate of only 6.5 percent of that at Location A, which prompted the sampling at the air heater locations to determine the source of the SO_3 loss.

Sampling on January 20 and 21, 2004, showed a decrease in SO_3 across the air heater on the gas side. As much as 82 percent of the SO_3 was removed from the flue gas stream (Tests A-AH-3 vs. B-AH-3). As much as 60 percent of the SO_3 was passed through to the air heater heated-air side (Tests A-AH-2 vs. D-AH-2).

An SO_3 mass balance at Locations A, B, and D, shows a loss of 17 percent and 33 percent of the SO_3 across the air heater for the tests on January 21, 2004. It is possible that this missing SO_3 may be condensing inside the air heater on either the air heater surfaces or the fly ash.

Table A-3. Task 3 Baseline Sulfur Trioxide Measurement Summary.

Date	Location	Test No.	Flue Gas		Gas Phase SO_3 Measurements		
			DSCFM[A]	°F[B]	PPMV[C]	lb/hr[D]	Dew Point, °F[E]
12/19/03	A	A-3-1	3004[F]	633	13.6	0.507	278
	F	F-3-1	768[F]	293	4.8	0.046	253
	G	G-3-1	848[F]	285	0.7	0.008	228
	A	A-3-2	3004[F]	630	15.1	0.563	280
	F	F-3-2	768[F]	291	1.7	0.016	236
	G	G-3-2	848[F]	285	1.9	0.020	241
1/20/04	A	A-AH-1	2978[G]	619	12.6	0.466	276
	B	B-AH-1	2596[G]	339	---[H]	---[H]	---[H]
	D	D-AH-1	2490[G]	542	6.5	0.201	219
1/21/04	A	A-AH-2	2978[G]	613	10.4	0.385	273
	B	B-AH-2	2596[G]	315	2.8	0.091	245
	D	D-AH-2	2490[G]	613	7.4	0.228	222
	A	A-AH-3	2978[G]	613	10.4	0.384	273
	B	B-AH-3	2596[G]	317	2.0	0.065	239
	D	D-AH-3	2490[G]	543	6.2	0.191	218
	B	B-AH-4	2596[G]	316	1.7	0.056	237

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit, as measured during SO_3 sampling
C – Parts per million by volume, as measured
D – Pounds per hour, calculated with historical airflow rates
E – Dew point as calculated:

$$1000/T_{dp} = 2.276 - 0.0294 \ln\left(P_{H_2O}\right) - 0.0858 \ln\left(P_{H_2SO_4}\right) + 0.0062 \ln\left(P_{H_2O}\right) \ln\left(P_{H_2SO_4}\right)^{1}$$

Where: *Tdp = Dew Point, Kelvin*
PH_2O = Partial Pressure, flue gas water vapor, mm Hg
PH_2SO_4 = Partial Pressure, flue gas sulfuric acid, mm Hg ($PH_2SO_4 = PSO_3$)

F – Flow rate only measured on December 17, 2003
G – Flow rate only measured on October 7, 2003
H – Sample train developed a leak during the test run, results are not valid

[1] Kiang, Y. H., *Predicting Dewpoints of Acid Gases*, Chemical Engineering, Feb. 9, 1981.

2.2.2. Hg Sampling

Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02.) All tests were 120 minutes in duration, with sampling occurring simultaneously at each location tested. A total of three mercury tests were performed during Task 3.

The first test was conducted on December 17, 2003, at Locations A, F, and G. Data referenced in Section 2.1 indicated a decrease in flue gas total mercury concentrations between Locations A and F. Further evaluations concluded that inadequate packing around the Location F sampling probe allowed ambient air to enter the sampling port and dilute the sample. When the final two tests were conducted on January 29, 2004, the port seal was better maintained, resulting in better agreement between the flue gas mercury concentrations at Locations A and F.

Based on the findings of the SO_3 sampling, discussed in Section 2.1, CONSOL decided to perform mercury sampling at Location B to further evaluate the fate of the mercury across the pilot system. Two tests were conducted at Location B (B-3-1 and B-3-2), simultaneously with tests two and three at Locations A, F, and G. Tables A-4 and A-5 summarize the mercury sampling for this task.

The test 1 particle-bound mercury concentration, at Location G, is higher than that from tests 2 and 3, even though total mercury concentration is less in test 1. It is expected that the total mercury concentration should remain unchanged between Locations A, B, and F; however, this was only the case with Test 3. Location F's total mercury concentrations were substantially lower than those from Locations A and B, during tests 1 and 2. Consequently, the mercury removal rate (Location F vs. Location G) measured during test 3 (33.2%) may be the only representative removal calculated for this task.

Table A-4. Task 3 Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, µg/dscm				Removal, %[G]
			Flow, DSCFM[A]	Temp., °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
12/17/03	A	A-3-1	3,000	596	1.20	5.97	8.20	15.37	6.0
	F	F-3-1	770	279	6.20	3.22	1.04	10.46	
	G	G-3-1	850	279	0.02	7.83	1.99	9.83	
1/29/04	A	A-3-2	2,810	616	0.61	6.59	8.18	15.38	5.4
	B	B-3-1	1,860	303	4.59	8.88	1.20	14.67	
	F	F-3-2	860	291	3.52	7.21	1.75	12.49	
	G	G-3-2	890	275	0.003	9.35	2.45	11.81	
1/29/04	A	A-3-3	2,910	607	0.82	5.60	8.41	14.83	33.2
	B	B-3-2	2,720	303	4.60	8.99	1.06	14.65	
	F	F-3-3	870	289	6.80	6.87	1.30	14.97	
	G	G-3-3	880	275	0.006	7.89	2.10	10.00	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Table A-5. Task 3 Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}, (µg/dscm)			Hg^{++}, (µg/dscm)			Hg^{0}, (µg/dscm)			Hg^{tot}, (µg/dscm)		
		X^A	δ^B	PRSD[C]	X	δ	PRSD	X	δ	PRSD	X	δ	PRSD
A	1, 2, 3	0.88	0.24	27.8	6.05	0.41	6.8	8.26	0.10	1.2	15.19	0.26	1.7
B[D]	1, 3	4.59	0.003	0.1	8.94	0.05	0.6	1.13	0.07	5.8	14.66	0.01	0.1
F	2, 3	5.16	1.64	31.7	7.04	0.17	2.5	1.53	0.22	14.7	13.73	1.24	9.0
G	2, 3	0.005	0.002	32.6	8.62	0.73	8.5	2.276	0.18	7.7	10.90	0.90	8.3
Removal	1, 2, 3										14.88	12.96	87.1

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation
D – Tests B-1 and B-2 were run simultaneously with tests 2 and 3 at Locations A, F, and G.

2.2.3. Particulate Sampling

Particulate concentrations were determined using the net weight gain of the Ontario-Hydro Method filters along with the weight of any solid material filtered out of the probe and/or heated sample line rinses. The particulate concentrations and mass flow rates measured during Task 3 are summarized in Table A-6.

Table A-6. Particulate Measurement Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Particulate		Removal, %[E]
			Flow, DSCFM[A]	Temp., °F[B]	Conc. gr/dscf[C]	Mass Flow, lb/hr[D]	
12/17/03	A	A-3-1	3,000	596	4.93	126.8	99.7
	F	F-3-1	770	279	2.90	19.9	
	G	G-3-1	850	279	0.01	0.06	
1/29/04	A	A-3-2	2,810	616	4.42	106.1	99.4
	B	B-3-1	1,860	303	5.72	93.2	
	F	F-3-2	860	291	3.20	24.7	
	G	G-3-2	890	275	0.02	0.13	
1/29/04	A	A-3-3	2,910	607	5.00	124.2	99.7
	B	B-3-2	2,720	303	4.86	112.6	
	F	F-3-3	870	289	3.90	30.1	
	G	G-3-3	880	275	0.01	0.11	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Grains per dry standard cubic foot
D – Pounds per hour
E – Location F vs. Location G, concentration based

2.2.4. Particle Size Distribution

CONSOL performed a particle size distribution (PSD) analysis at the ESP inlet and outlet (Locations F and G, respectively). Due to the high particulate loading a Southern Research five-stage cyclone was used at Location F. An Anderson seven-stage impactor was used at Location G. The devices operate at a constant sample rate, and segregate particles, by diameter, into separate stages.

Single tests were performed at each location, simultaneously, on January 27, and on January 28, 2004. A mercury analysis was also performed on each stage of the particle size instruments to determine if any correlation between particle size and mercury concentration could be observed.

Table A-7. Particle Size Determination Summary

Test No.	Location	Separation Stage	D_{50}[A], µm	Mass %	GMD[B], µm	Hg, ug/dscm[C]
1	F (cyclone)	1	8.9	79.82	29.8	1.18
		2	4.4	13.77	6.3	0.57
		3	3.1	2.97	3.7	0.26
		4	1.5	0.89	2.2	ND[D]
		5	0.89	1.59	1.2	ND
		Final Filter	0.45	0.95	0.63	0.30
	G (impactor)	Preseparator	7.3	47.28	27.11	0.02
		1	4.3	26.26	5.62	0.11
		2	2.7	4.47	3.42	0.25
		3	1.8	11.48	2.19	0.22
		4	1.1	3.11	1.37	0.27
		5	0.5	1.36	0.71	0.27
		6	0.42	0.78	0.45	0.25
		7	0.17	5.06	0.27	0.27
		Final Filter	0.09	0.19	0.12	0.11
2	F (cyclone)	1	8.9	81.4	29.9	0.98
		2	4.5	12.83	6.3	0.43
		3	3.2	2.32	3.8	0.16
		4	1.5	1.99	2.2	ND
		5	0.90	0.24	1.2	ND
		Final Filter	0.45	1.21	0.64	0.30
	G (impactor)	Preseparator	6.2	46.95	24.98	0.01
		1	3.5	12.68	4.66	0.09
		2	2.2	4.23	2.78	0.22
		3	1.5	15.02	1.80	0.19
		4	0.9	2.35	1.13	0.23
		5	0.3	4.69	0.50	0.24
		6	0.34	2.35	0.31	0.22
		7	0.10	11.74	0.19	0.23
		Final Filter	0.05	0.00	0.07	0.10

A – 50% cutpoint diameter, microns (i.e. 50% of the particles in the stage are this size or larger, but smaller than the previous stage.)

B – Geometric mean particle diameter, microns

C - Measured micrograms of particle-bound mercury per dry standard cubic meter by particle diameter

Most particles at the ESP Inlet were larger than 8.9 μm in diameter and, as such, were easily removed by the ESP. Particles in this diameter fraction displayed higher mercury concentrations than those with smaller diameters. At the ESP Outlet the larger particles contained little mercury. Instead, the mercury that was present was distributed across the particle size range, which was also well distributed below 6-7 μm.

3.0 Task 4 – Sorbent Evaluation

3.3 Details

Tasks four through seven involve decreasing process temperatures to determine the effect of the change on mercury removal. With temperature decreases the concern of sulfur trioxide (SO_3) condensation on the metal surfaces of the process interiors, particularly the air heater and the ESP, rises. To combat this problem, a magnesium hydroxide ($Mg(OH)_2$) spray was injected downstream of Location A. Sampling in this task was conducted to determine the proper $Mg(OH)_2$ injection rate, the results of which will serve as a baseline for future tasks. Sampling in Task 4 consisted of flue gas volumetric flow rates and SO_3 sampling around the air heater; and mercury, total particulate matter (PM), and particle size distribution (PSD) at the ESP locations. Table A-8 outlines the sampling schedule.

Table A-8. Task 4 Sampling Matrix.

Date	Parameter	Location	No. of Tests
02/24/04	Hg	F, G	1
02/27/04	Hg	F, G	1
	PSD	F, G	2
03/01/04	Hg	F, G	1
	PSD	F, G	1
03/02/04	SO_3	A, B, D, H	2
	Flows	A, B, C, D	1
03/03/04	SO_3	A, B, D, H	2

3.3.1. Pilot Plant Operations

Magnesium hydroxide was injected to the pilot plant immediately downstream of Location A. The initial stoichiometric injection ratio of 2.5 moles $Mg(OH)_2$: 1 mole SO_3 was used for mercury and PSD sampling at the ESP sites. Sulfur trioxide sampling conducted at the air heater sites on March 2, 2004, showed this ratio did not adequately reduce the SO_3 concentration at Location D enough to eliminate potential air heater SO_3 condensation problems. The stoichiometric rate was doubled to 5:1 for sampling on March 3, 2004, resulting in gas phase SO_3 concentrations that were reduced to under two parts per million, corrected to zero percent oxygen.

Flue gas temperature was reduced to 240°F by the air heater for this task. The ESP was still experiencing decreased efficiencies. Appendix B further details the pilot plant operations. During each sampling period samples were taken of the host plant coal, host plant ESP ash, and pilot plant ESP ash to determine a process mass balance.

3.3.2. Sampling

Task 4 plans consisted of SO_3 sampling at Locations A, B, and D to determine the proper $Mg(OH)_2$ mix ratio before conducting the mercury and PSD sampling at the ESP locations (F and G). However, due to the possibility of ESP malfunctions increasing with operation time, CONSOL determined it would better suit the program to test the ESP locations using the preliminary injection rate, and then remove the ESP from service and sample around the air heater to verify the injection rate.

3.4 Results

3.4.1. SO_3 Sampling

The original plans to conduct sampling at Locations A, B, and D, were expanded to include sampling at a new location, the gas outlet of the air heater, designated Location H. Sampling at Location H would show if any of the SO_3 was migrating through the air heater basket seals from the gas side to the air side. Two tests were conducted at the four locations on March 2, 2004, which resulted in gas-phase SO_3 concentrations that were no less than 3.3 ppmv, corrected to 0% oxygen. The stoichiometric rate was doubled, resulting in gas-phase SO_3 concentrations below 2 ppmv, corrected to 0% oxygen, which allowed for a calculated SO_3 dew point of less than 240°F. Table A-9 summarizes the sampling.

Table A-9. Task 4 SO_3 Sampling

Date	Location	Test No.	Flue Gas		Gas Phase SO_3 Measurements		
			Flow, DSCFM[A]	Temp., °F[B]	Conc. gr/dscf[C]	Mass Flow, lb/hr[D]	Dew Point, °F[E]
03/02/04	A	A-4-1	3174	611	33.3	1.03	288
		A-4-2	3174	614	29.5	0.91	286
	B	B-4-1	2833	253	1.0	0.03	227
		B-4-2	2833	254	1.5	0.04	232
	D	D-4-1	2744	485	25.8	0.06	214
		D-4-2	2744	487	31.3	0.07	217
	H	H-4-1	2744	579	10.2	0.30	265
		H-4-2	2744	581	3.3	0.10	247
03/03/04	A	A-4-3	3174	613	34.3	1.03	289
		A-4-4	3174	594	30.7	0.95	287
	B	B-4-3	2833	254	0.8	0.02	224
		B-4-4	2833	254	0.6	0.02	220
	D	D-4-3	2744	491	8.5	0.01	193
		D-4-4	2744	475	4.4	0.01	192
	H	H-4-3	2744	579	2.1	0.06	239
		H-4-4	2744	558	1.4	0.04	234

A – Dry standard cubic feet per minute, measured on March 3, 2004
B – Degrees Fahrenheit, as measured during SO_3 sampling
C – Parts per million by volume, as measured
D – Pounds per hour, calculated with March 3, airflow rates
E – Dew point as calculated:

$$1000/T_{dp} = 2.276 - 0.0294 \ln\left(P_{H_2O}\right) - 0.0858 \ln\left(P_{H_2SO_4}\right) + 0.0062 \ln\left(P_{H_2O}\right) \ln\left(P_{H_2SO_4}\right)$$

3.4.2. Hg Sampling

Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02.) All tests were 120 minutes in duration, with sampling occurring simultaneously at Locations F and G. A total of three mercury tests were performed during Task 4.

Test one was conducted on February 24, 2004, and tests two and three were conducted on February 27 and March 1, 2004, respectively. Tables A-10 and A-11 summarize the mercury sampling for this task.

Table A-10. Task 4 Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, (μg/dscm)				Removal, %[G]
			Flow, DSCFM[A]	Temp., °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
02/24/04	F	F-4-1	855	235	13.20	0.98	0.57	14.74	42.0
	G	G-4-1	994	247	0.03	6.74	1.78	8.56	
02/27/04	F	F-4-2	850	238	10.96	0.72	0.00	11.67	31.0
	G	G-4-2	974	247	0.01	5.92	2.12	8.05	
03/01/04	F	F-4-3	847	239	13.93	1.25	0.00	15.18	29.8
	G	G-4-3	972	251	0.01	7.89	2.76	10.66	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Table A-11. Task 4 Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}, (μg/dscm)			Hg^{++}, (μg/dscm)			Hg^{0}, (μg/dscm)			Hg^{tot}, (μg/dscm)		
		$\bar{X}$[A]	δ[B]	PRSD[C]	$\bar{X}$	δ	PRSD	$\bar{X}$	δ	PRSD	$\bar{X}$	δ	PRSD
F	1, 2, 3	12.69	1.55	12.2	0.98	0.27	27.6	0.19	0.33	173.7	13.87	1.91	13.8
G	1, 2, 3	0.017	0.01	58.8	6.85	0.99	14.4	2.22	0.50	22.5	9.09	1.39	15.3
Removal	1, 2, 3										34.27	6.72	19.6

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation

3.4.3. Particulate Sampling

Particulate concentrations were determined using the net weight gain of the Ontario-Hydro Method filters along with the weight of any solid material filtered out of the probe and/or heated sample line rinses. The particulate concentrations and mass flow rates measured during Task 4 are summarized in Table A-12.

Table A-12. Task 4 Particulate Measurement Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Particulate		Removal, %[E]
			Flow, DSCFM[A]	Temp., °F[B]	Conc. gr/dscf[C]	Mass Flow, lb/hr[D]	
02/24/04	F	F-4-1	855	235	3.67	28.33	99.4
	G	G-4-1	994	247	0.022	0.19	
02/27/04	F	F-4-2	850	238	2.81	19.28	99.8
	G	G-4-2	974	247	0.005	0.04	
03/01/04	F	F-4-3	847	239	3.68	25.24	99.6
	G	G-4-3	972	251	0.015	0.13	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Grains per dry standard cubic foot
D – Pounds per hour
E – Location F vs. Location G, concentration based

3.4.4. Particle Size Distribution

CONSOL performed a particle size distribution (PSD) analysis at the ESP inlet and outlet (Locations F and G, respectively). Due to the high particulate loading a Southern Research five-stage cyclone was used at Location F. An Anderson seven stage impactor was used at Location G. The devices segregate particles, by diameter, into separate stages, and are operated at a constant sample rate.

Three tests were performed at each location. The first two tests were conducted on February 27 and one test was conducted on February 28, 2004. A mercury analysis was also performed on each stage of the particle size instruments to determine if any correlation between particle size and mercury concentration could be observed.

Table A-13. Task 4 Particle Size Determination Summary

Test No.	Location	Separation Stage	D_{50}[A], µm	Mass %	GMD[B], µm	Hg, ug/dscm[C]
1	F (cyclone)	1	8.7	62.33	29.5	1.73
		2	4.3	28.45	6.1	1.85
		3	2.9	2.70	3.6	0.12
		4	1.5	4.12	2.1	0.42
		5	0.91	1.59	1.2	0.18
		Final Filter	0.46	0.81	0.65	0.06
	G (impactor)	Preseparator	9.2	5.78	30.30	0.00
		1	5.7	14.08	7.20	0.03
		2	3.6	23.83	4.50	0.05
		3	2.3	17.33	2.85	0.04
		4	1.4	17.33	1.77	0.05
		5	0.8	2.53	1.06	0.05
		6	0.55	7.58	0.67	0.04
		7	0.29	9.75	0.40	0.05
		Final Filter	0.15	1.81	0.21	0.28
2	F (cyclone)	1	8.6	84.88	29.2	7.20
		2	4.2	7.57	6.0	1.27
		3	2.8	5.15	3.5	0.92
		4	1.4	1.46	2.0	0.88
		5	0.89	0.53	1.1	0.24
		Final Filter	0.44	0.41	0.63	0.20
	G (impactor)	Preseparator	9.2	3.98	30.40	0.00
		1	5.7	4.59	7.25	0.04
		2	3.6	12.54	4.54	0.05
		3	2.3	6.73	2.87	0.04
		4	1.4	17.74	1.79	0.06
		5	0.8	11.31	1.07	0.07
		6	0.56	17.13	0.68	0.04
		7	0.30	21.71	0.41	0.04
		Final Filter	0.15	4.28	0.21	0.22

Table A-13, cont.

Test No.	Location	Separation Stage	D_{50}[A], μm	Mass %	GMD[B], μm	Hg, ug/dscm[C]
3	F	1	8.6	85.88	29.3	5.90
		2	4.2	8.68	6.0	0.98
		3	2.8	3.18	3.5	0.24
		4	1.4	1.52	2.0	0.20
		5	0.90	0.03	1.1	0.00
		Final Filter	0.45	0.71	0.63	0.01
	G	Preseparator	9.1	10.25	30.23	0.00
		1	5.6	10.08	7.16	0.07
		2	3.6	14.29	4.48	0.06
		3	2.2	14.45	2.83	0.06
		4	1.4	7.06	1.76	0.05
		5	0.8	8.91	1.05	0.05
		6	0.55	15.29	0.66	0.04
		7	0.29	10.92	0.40	0.03
		Final Filter	0.14	8.74	0.20	0.16

A – 50% cutpoint diameter, microns (i.e. 50% of the particles in the stage are this size or larger, but smaller than the previous stage.)
B – Geometric mean particle diameter, microns
C - Measured micrograms of particle-bound mercury per dry standard cubic meter by particle diameter

Most particles at the ESP Inlet were larger than 8.6 μm in diameter and, as such, were easily removed by the ESP. Particles of this diameter also displayed higher mercury concentrations. As particle diameters decreased at the ESP Inlet, so too did the mercury concentration. At the ESP Outlet the larger particles contained little mercury. Instead, the mercury that was present was fairly evenly distributed across the particle size range, which was also well distributed below 6 μm.

4.0 Task 5 – Parametric Testing

4.5 Details

To determine the effect of flue gas temperature reduction on mercury control, CONSOL adjusted the air heater to provide a flue gas outlet temperature of 225°F. The magnesium hydroxide ($Mg(OH)_2$) spray was injected at the stoichiometric rate of 5:1 that was selected on the basis of Task 4 results.

Sampling in Task 5 consisted of mercury and total particulate matter (PM) measurements at the ESP locations. Table A-14 outlines the sampling schedule.

Table A-14. Task 5 Sampling Matrix.

Date	Parameter	Location	No. of Tests
03/24/04	Hg	F, G	1
03/25/04	Hg	F, G	2

4.5.1. Pilot Plant Operations

Magnesium hydroxide was injected to the pilot plant immediately downstream of Location A to control SO_3 condensation that could result from flue gas temperature reduction by the air heater. Flue gas temperature was reduced to 225°F for this task. The ESP was still experiencing decreased voltages. Appendix B further details the pilot plant operations. During each sampling period samples were taken of the host plant coal, host plant ESP ash, and pilot plant ESP ash to determine a process mass balance.

4.5.2. Sampling

Task 5 plans consisted of sampling mercury at the ESP inlet and outlet locations (F and G) only.

4.6 Results

4.6.1. Hg Sampling

Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02.) All tests were 120 minutes in duration, with sampling occurring simultaneously at Locations F and G. A total of three mercury tests were performed during Task 5.

Test one was conducted on March 24, 2004, and tests two and three were conducted on March 25, 2004. Tables A-15 and A-16 summarize the mercury sampling for this task.

Table A-15. Task 5 Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, µg/dscm				Removal, %[G]
			Flow, DSCFM[A]	Temp. °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
03/24/04	F	F-5-1	829	230	12.29	2.31	0.55	15.14	42.1
	G	G-5-1	871	210	0.08	5.91	2.78	8.76	
03/25/04	F	F-5-2	831	233	12.87	1.63	0.51	15.01	27.4
	G	G-5-2	878	215	0.12	8.57	2.21	10.90	
	F	F-5-3	810	234	13.55	0.75	0.53	14.83	81.8
	G	G-5-3	847	219	0.20	2.09	0.41	2.70	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Table A-16. Task 5 Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}			Hg^{++}			Hg^{0}			Hg^{tot}		
		$\bar{x}$[A]	δ[B]	PRSD[C]	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD
F	1, 2, 3	12.90	0.63	4.9	1.56	0.78	50.0	0.53	0.02	3.8	14.99	0.16	1.1
G	1, 2, 3	0.13	0.06	46.2	5.52	3.26	59.1	1.80	1.24	68.9	7.45	4.25	57.0
Removal	1, 2, 3										50.28	28.15	56.0

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation

4.6.2. Particulate Sampling

Particulate concentrations were determined using the net weight gain of the Ontario-Hydro Method filters along with the weight of any solid material filtered out of the probe and/or heated sample line rinses. The particulate concentrations and mass flow rates measured during Task 5 are summarized in Table A-17.

Table A-17. Task 5 Particulate Measurement Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Particulate		Removal, %[E]
			Flow, DSCFM[A]	Temp., °F[B]	Conc. gr/dscf[C]	Mass Flow, lb/hr[D]	
03/24/04	F	F-5-1	829	230	2.75	18.86	98.9
	G	G-5-1	871	210	0.03	0.23	
03/25/04	F	F-5-2	831	233	2.59	17.79	93.8
	G	G-5-2	878	215	0.16	1.22	
	F	F-5-2	810	234	2.74	18.81	95.6
	G	G-5-2	847	219	0.12	0.83	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Grains per dry standard cubic foot
D – Pounds per hour
E – Location F vs. Location G, concentration based

5.0 Task 6 –Humidification Test

5.1 Details

To determine the effect of flue gas temperature reduction on mercury control, CONSOL injected a water spray upstream of the ESP to provide an ESP inlet flue gas temperature of approximately 240°F, following an air heater outlet temperature of 300°F. The magnesium hydroxide ($Mg(OH)_2$) spray was injected at the stoichiometric rate of 5:1 that was selected on the basis of Task 4 results.

Sampling in Task 6 consisted of mercury and total particulate matter (PM) measurements at the ESP locations (F and G) and also upstream of the water injection port, at Location E. Table A-18 outlines the sampling schedule.

Table A-18. Task 6 Sampling Matrix.

Date	Parameter	Location	No. of Tests
04/01/04	Hg	E, F, & G	1
04/13/04	Hg	E, F, & G	2

5.1.1. Pilot Plant Operations

Magnesium hydroxide was injected to the pilot plant immediately downstream of Location A to control SO_3 condensation that could result from the flue gas temperature reduction planned for this task. The air heater outlet flue gas temperature was

maintained at 300°F by air heater adjustments. The humidification water was injected at a rate of approximately 4.5 gallons per minute, which dropped the flue gas temperature to approximately 240°F.

Repairs on the ESP resulted in higher voltages across the collection fields, which improved particulate control efficiency for this task. Appendix B further details the pilot plant operations. During each sampling period samples were taken of the host plant coal, host plant ESP ash, and pilot plant ESP ash to determine a process mass balance.

5.1.2. Sampling

Task 6 plans consisted of sampling mercury upstream of the humidification port (Location E) and at the ESP inlet and outlet locations (F and G) only.

5.2 Results

5.2.1. Hg Sampling

Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02.) All tests were 120 minutes in duration, with sampling occurring simultaneously at Locations E, F, and G. A total of three mercury tests were performed during Task 6.

Test one was conducted on April 1, 2004. At the conclusion of test one, the pilot plant operator noticed the pilot ESP ash collection system was not operating properly. The additional moisture from the humidification had plugged the collection device preventing the collection of an ESP ash sample for this test. The remaining sampling was postponed until repairs could be conducted.

In the following weeks the system was cleaned out and the sample collection piping was heat-traced to minimize condensation. In addition, an ESP repair person arrived at the pilot plant and made repairs to the ESP electrical system.

Tests two and three were conducted on April 13, 2004, following the repairs. Tables A-19 and A-20 summarize the mercury sampling for this task.

Table A-19. Task 6 Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, µg/dscm				Removal, %[G]
			Flow DSCFM[A]	Temp. °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
04/01/04	E	E-6-1	705	287	2.31	9.84	0.97	13.12	9.6
	F	F-6-1	788	249	7.50	3.52	1.43	12.45	
	G	G-6-1	832	219	0.09	7.52	3.64	11.25	
04/13/04	E	E-6-2	743	293	13.67	0.59	0.51	14.77	49.7
	F	F-6-2	750	249	10.39	0.70	0.54	11.64	
	G	G-6-2	876	220	0.02	3.80	2.04	5.86	
	E	E-6-3	740	292	9.76	0.74	0.53	11.04	50.5
	F	F-6-3	751	250	11.16	0.72	0.53	12.41	
	G	G-6-3	889	220	0.05	3.98	2.12	6.14	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Test one, conducted prior to the repairs, was not representative of the actual results and therefore should not be considered in any data evaluation. The results of test one are not included in Table A-20.

Table A-20. Task 6 Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}			Hg^{++}			Hg^{0}			Hg^{tot}		
		$\bar{x}$[A]	δ[B]	PRSD[C]	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD
E	2 & 3	11.72	2.77	23.6	0.67	0.11	16.4	0.52	0.02	3.8	12.90	2.64	20.5
F	2 & 3	10.78	0.54	5.0	0.71	0.01	1.4	0.54	0.01	1.9	12.03	0.54	4.5
G	2 & 3	0.04	0.02	50.0	3.89	0.13	3.3	2.08	0.05	2.4	6.00	0.20	3.3
Removal	2 & 3										50.08	0.58	1.2

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation

5.2.2. Particulate Sampling

Particulate concentrations were determined using the net weight gain of the Ontario-Hydro Method filters along with the weight of any solid material filtered out of the probe and/or heated sample line rinses. The particulate concentrations and mass flow rates measured during Task 6 are summarized in Table A-21.

Table A-21. Task 6 Particulate Measurement Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Particulate		Removal, %[E]
			Flow, DSCFM[A]	Temp., °F[B]	Conc., gr/dscf[C]	Mass Flow, lb/hr[D]	
04/01/04	E	E-6-1	705	287	1.88	11.26	98.9
	F	F-6-1	788	249	2.68	11.38	
	G	G-6-1	832	219	0.03	0.21	
04/13/04	E	E-6-2	743	293	3.14	18.87	99.5
	F	F-6-2	750	249	2.18	14.93	
	G	G-6-2	876	220	0.01	0.06	
	E	E-6-3	740	292	1.96	11.73	99.6
	F	F-6-3	751	250	2.37	16.24	
	G	G-6-3	889	220	0.01	0.11	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Grains per dry standard cubic foot
D – Pounds per hour
E – Location F vs. Location G, concentration based

6.0 Task 7 – Long Term Testing

6.1 Details

The final task involved sampling the pilot plant while it was operating at favored conditions selected on the basis of Task 3 through 6 results. Testing conducted at the beginning of Task 7 (commencing testing), then again, prior to removing the plant from service (concluding testing), to determine any change in mercury removal. Sampling in Task 7 consisted of SO_3 sampling around the air heater; and mercury and total particulate matter (PM) at the ESP locations. Table A-22 outlines the sampling schedule.

Table A-22. Task 7 Sampling Matrix.

Date	Phase	Parameter	Location	No. of Tests
09/08/04	Commencing Testing	Hg	F & G	1
		SO_3	A & H	1
09/09/04		Hg	F & G	2
		SO_3	A & H	2
12/15/04	Concluding Testing	Hg	F & G	2
		SO_3	A & H	2
12/16/04		Hg	F & G	2
		SO_3	A & H	3
12/17/04		Hg	F & G	1

6.1.1. Pilot Plant Operations

During Task 7, magnesium hydroxide (approx. 4:1 molar ratio) was injected to the pilot plant immediately downstream of Location A to control SO_3 fouling and corrosion. Flue gas temperatures were decreased to 230 °F at the air heater outlet by air heater adjustments.

During the concluding testing on December 15 through 17, 2004, the first three mercury tests were performed while the system was operating as it had throughout the duration of Task 7. When these tests were completed, the air heater was adjusted to increase the flue gas temperature to 270 °F at the air heater outlet, and flue gas cooling to 230 °F was achieved via humidification. Two additional tests were conducted before the ESP began to malfunction as a result of the increased moisture in the flue gas.

Appendix B further details the pilot plant operations. During each sampling period samples were taken of the host plant coal, host plant ESP ash, and pilot plant ESP ash to determine a process mass balance.

6.1.2. Sampling

Task 7 plans consisted of SO_3 sampling at Locations A and H and mercury sampling at the ESP inlet and outlet (Locations G and H) to determine if the system experienced any changes in pollutant control efficiencies over time.

6.2 Results

6.2.1. SO_3 Sampling

Sampling was conducted at Locations A and H. Three tests were conducted during the commencing testing on September 8 and 9, 2004. Five tests were conducted during the concluding test period on December 15 and 16, 2004; however the results from a

test at each location were incomplete as a result of sample train problems. The probe filter plug from first test at location H, on December 15, was lost in the duct, resulting in the loss of that sample fraction. During the third test at Location A, the sample train probe heating system malfunctioned, causing the probe to be unheated, which would not allow accurate results; therefore this test was also eliminated from consideration. As a result of these problems, two additional tests were conducted to provide a total of three data sets.

Table A-23 summarizes the sampling results.

Table A-23. Task 7 SO_3 Sampling

Date	Test No.	Location	Flue Gas		Gas Phase SO_3 Measurements		
			Flow, DSCFM[A]	Temp., °F[B]	Conc. gr/dscf[C]	Mass Flow, lb/hr[D]	Dew Point, °F[E]
9/8/04	1	A	2984	637	3.9	0.14	253
		H	2984	582	0.6	0.02	227
9/9/04	2	A	2984	539	17.7	0.66	279
		H	2984	499	0.8	0.03	228
	3	A	2984	531	19.9	0.74	282
		H	2984	486	3.6	0.13	251
12/15/04	4	A	2984	618	4.3	0.16	255
		H	2984	577	Sample Void – Filter plug loss		
	5	A	2984	619	7.6	0.28	265
		H	2984	578	1.0	0.04	231
12/16/04	6	A	Sample Void – Probe Heater Malfunction				
		H	2984	522	2.8	0.10	247
	7	A	2984	561	18.6	0.69	281
		H	2984	521	2.3	0.09	244
	8	A	2984	542	20.8	0.77	283
		H	2984	508	5.1	0.19	257

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit, as measured during SO_3 sampling
C – Parts per million by volume, as measured
D – Pounds per hour
E – Dew point as calculated:

$$1000/T_{dp} = 2.276 - 0.0294 \ln\left(P_{H_2O}\right) - 0.0858 \ln\left(P_{H_2SO_4}\right) + 0.0062 \ln\left(P_{H_2O}\right) \ln\left(P_{H_2SO_4}\right)$$

6.2.2. Hg Sampling

Mercury sampling was performed with the Ontario-Hydro Mercury Speciation Method (ASTM Method D-6784-02.) All tests were 120 minutes in duration, with sampling occurring simultaneously at Locations F and G. A total of three mercury tests were performed during Task 7 commencing measurements and five tests were conducted during concluding testing; three with air heater flue gas cooling, and two with humidification flue gas cooling.

Tables A-24 through A-28 summarize the mercury sampling for this task.

Table A-24.Task 7 Baseline Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, μg/dscm				Removal, %[G]
			Flow DSCFM[A]	Temp., °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
09/08/04	F	F-7-1	900	198	9.65	0.85	0.16	10.66	96.7
	G	G-7-1	1000	217	0.07	0.18	0.10	0.35	
09/09/04	F	F-7-2	900	203	13.99	0.70	0.22	14.91	75.2
	G	G-7-2	600	222	0.07	3.19	0.44	3.69	
09/09/04	F	F-7-3	900	210	12.56	0.64	0.23	13.43	77.8
	G	G-7-3	900	223	0.02	2.58	0.38	2.99	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Table A-25. Task 7 Baseline Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}, (μg/dscm)			Hg^{++}, (μg/dscm)			Hg^{0}, (μg/dscm)			Hg^{tot}, (μg/dscm)		
		$\bar{X}$[A]	δ[B]	PRSD[C]	$\bar{X}$	δ	PRSD	$\bar{X}$	δ	PRSD	$\bar{X}$	δ	PRSD
F	1, 2, 3	12.07	2.21	18.3	0.73	0.11	15.3	0.20	0.04	20.4	13.0	2.16	16.6
G	1, 2, 3	0.05	0.03	57.5	1.99	1.59	80.0	0.31	0.18	60.2	2.34	1.76	75.2
Removal	1, 2, 3										83.2	11.7	14.1

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation

Table A-26. Task 7 Follow-up Mercury Sampling Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, μg/dscm				Removal, %[G]
			Flow DSCFM[A]	Temp., °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
12/15/04	F	F-7-4	1000	201	10.23	1.47	0.18	11.88	94.7
	G	G-7-4	1100	200	0.02	0.49	0.11	0.62	
12/15/04	F	F-7-5	900	198	12.29	2.37	0.19	18.84	96.3
	G	G-7-5	1100	201	0.01	0.44	0.10	0.54	
12/16/04	F	F-7-6	900	205	12.5	1.30	0.21	14.01	81.8
	G	G-7-6	1100	203	0.02	2.05	0.48	2.55	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

Table A-27. Task 7 Follow-up Mercury Sampling Statistical Evaluation.

Location	Test Nos.	Hg^{part}, (μg/dscm)			Hg^{++}, (μg/dscm)			Hg^{0}, (μg/dscm)			Hg^{tot}, (μg/dscm)		
		$\bar{x}$[A]	δ[B]	PRSD[C]	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD	$\bar{x}$	δ	PRSD
F	4, 5, 6	11.67	1.26	10.8	1.71	0.57	33.4	0.19	0.02	7.9	13.58	1.53	11.3
G	4, 5, 6	0.02	0.01	38.3	0.99	0.92	92.3	0.23	0.22	96.1	1.24	1.14	91.7
Removal	4, 5, 6										91.0	8.0	8.8

A – Arithmetic mean
B – Standard deviation of the population
C – Percent relative standard deviation

Table A-28. Task 7 Follow-up Mercury Sampling Summary (Humidification).

Date	Location	Test No.	Flue Gas		Flue Gas Mercury Concentration, μg/dscm				Removal, %[G]
			Flow DSCFM[A]	Temp., °F[B]	Hg^{partC}	Hg^{++D}	Hg^{0E}	Hg^{totF}	
12/16/04	F	F-7-7	1000	208	10.33	0.64	0.21	11.19	67.8
	G	G-7-7	1200	206	0.04	2.94	0.62	3.60	
12/17/04	F	F-7-8	900	209	13.75	0.63	0.22	14.60	80.7
	G	G-7-8	1100	207	0.04	2.21	0.57	2.82	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Particle bound mercury, corrected to 0% oxygen
D – Oxidized mercury, corrected to 0% oxygen
E – Elemental mercury, corrected to 0% oxygen
F – Total mercury, corrected to 0% oxygen
G – Location F vs. Location G, concentration based

6.2.3. Particulate Sampling

Particulate concentrations were determined using the net weight gain of the Ontario-Hydro Method filters along with the weight of any solid material filtered out of the probe and/or heated sample line rinses. The particulate concentrations and mass flow rates measured during Task 7 are summarized in Table A-29.

Table A-29. Task 7 Particulate Measurement Summary.

Date	Location	Test No.	Flue Gas		Flue Gas Particulate		Removal, %[E]
			Flow, DSCFM[A]	Temp., °F[B]	Conc., gr/dscf[C]	Mass Flow, lb/hr[D]	
09/08/04	F	F-7-1	900	198	3.43	26.5	99.8
	G	G-7-1	1000	217	0.01	0.07	
09/09/04	F	F-7-2	900	203	3.57	27.6	99.5
	G	G-7-2	600	222	0.02	0.10	
09/09/04	F	F-7-3	900	210	2.68	20.7	99.5
	G	G-7-3	900	223	0.01	0.10	
12/15/04	F	F-7-4	1000	201	4.41	37.8	99.2
	G	G-7-4	1100	200	0.03	0.29	
12/15/04	F	F-7-5	900	198	4.75	36.7	99.3
	G	G-7-5	1100	201	0.03	0.25	
12/16/04	F	F-7-6	900	205	3.81	29.4	99.3
	G	G-7-6	1100	203	0.02	0.20	
12/16/04	F	F-7-7	1000	208	3.00	25.8	99.1
	G	G-7-7	1200	206	0.02	0.24	
12/17/04	F	F-7-8	900	209	3.88	30.0	96.9
	G	G-7-8	1100	207	0.10	0.92	

A – Dry standard cubic feet per minute
B – Degrees Fahrenheit
C – Grains per dry standard cubic foot
D – Pounds per hour
E – Location F vs. Location G, concentration based

7.0 Quality Assurance/Quality Control

The sampling and analysis QA/QC procedures are described below.

- Personnel specifically trained and experienced in power plant sampling methods, including the Ontario-Hydro mercury sampling method, conducted all sampling,
- The sampling equipment was maintained and calibrated as required,
- Consistent sample preparation and recovery procedures were used,
- Samples were logged and tracked under the direction of sample team Group

Leader,

- Individual calibration curves were developed for each sample matrix,
- NIST Standard Reference Material (SRM) and lab QC samples were analyzed to verify calibration curves,
- Duplicates of selected samples were analyzed to assure repeatability,
- Analyses of selected "spiked" samples were analyzed to assure sample recovery, and
- Interim data were reviewed to assure sample completeness.

All samples were obtained using the procedures described in EPA Method 5 and the Ontario-Hydro mercury speciation draft method. Data were recorded on standard forms, which are included in Appendix A. The field data were reduced using standard "in-house" spreadsheets. Copies of the summary sheets are included in Appendix A. To assure consistency, all of the Ontario-Hydro train components were prepared and recovered under the supervision of a senior technician experienced in the Ontario-Hydro mercury speciation lab techniques. Copies of the recovery sheets are included in Appendix A.

The Ontario-Hydro sampling train analysis consisted of eight sub-samples. Each sub-sample analysis consisted of developing a calibration curve (absorbance versus mercury concentration in solution), checks of field and lab blanks, calibration checks with SRM and lab standards, selected duplicates, and selected sample spikes. The laboratory summaries for each of these runs are contained in Appendix A.

7.1 Blank Samples

Blank liquid samples were analyzed for each liquid used in sampling and sample recovery. The average blank value was <1.0 ng/mL (ppb in solution). The average blank value is much less than any individual Hg^{part}, Hg^{++}, or Hg^{0} determination in ng/mL and, more importantly, is much less than the mercury concentration detection limit (discussed later in this report). Consequently, in this report, blank concentrations were not subtracted out from any mercury determination.

7.2 NIST Standard Reference Material Checks

NIST Standard Reference Material (SRM) checks were conducted throughout the mercury determinations. Two standards were used in the determinations as detailed in Table A-30.

Table A-30. NIST SRM analyses

NIST SRM	Standard Value (ng/mL)	Sample Fraction
1641D	8.0	Ontario Hydro Liquids
		Ontario Hydro Filters
1633b	149.0	Ontario Hydro Filters

7.3 Spike Sample Recoveries

Samples were spiked with a 2 or 10 μg/L mercury standard and then re-analyzed to determine the percent spike recovery.

7.4 Duplicate Analyses

Duplicate analyses were conducted periodically throughout the mercury determinations.

7.5 Flue Gas Mercury Concentration Detection Limits

For liquid samples, the flue gas mercury concentration was calculated using the following equation:

$$Hg\left[\mu g / m^3\right] = \frac{\left(C_{imp}\ x V_{imp}\right)}{\left(V_{gas}\ x 1000\right)}$$

where: C_{imp} = Mercury concentration of impinger solution [ng/mL (ppb)]

V_{imp} = Liquid volume of impinger solution [mL]

V_{gas} = Flue gas sample volume [dry standard m^3]

1000 = Conversion factor [1000 ng per μg]

The flue gas mercury detection limit is reduced when the flue gas sample volume is increased or liquid volume of impinger solution is decreased. The CVAA is calibrated between 0 and 20 ng/mL. Over this range, the calibration curve between absorbance and concentration is linear. The lowest concentration standard used to develop the calibration curve is 0.500 ng/mL. In addition, the detection limit of the liquid CVAA analysis was <1.0 ng/mL. The sampling variables result in sample-specific flue gas detection limit.

7.6 Concentration Verification

7.6.1. Mercury

The concentrations of mercury measured at locations upstream of the pilot ESP during each task were compared to theoretical and calculated concentrations. Theoretical values were derived by applying the as-fired coal concentration of mercury to the coal heating value (Btu/lb), fuel F-factor (dry basis), and correcting for flue gas moisture. Calculated values are based on the calculated firing rate as determined from flue gas flue gas excess air values.

A comparison of the calculated value to the theoretical value will provide a quality check on how well the pilot plant flue gas compares with the theoretical plant flue gas. Comparing the calculated values to the measured values shows how well the measured values reflect the pilot plant concentrations.

The following tables summarize the comparisons for mercury concentrations by task.

Table A-31. Task 3 mercury comparisons.

Location	A	F	A	B	F	A	B	F
Date	12/17/03	12/17/03	1/29/04	1/29/04	1/29/04	1/29/04	1/29/04	1/29/04
Test Number	A-3-1	F-3-1	A-3-2	B-3-1	F-3-2	A-3-3	B-3-2	F-3-3
ppm Hg in Coal	0.11	0.11	0.13	0.13	0.13	0.12	0.12	0.12
Coal Btu/lb (Actual)	14918	14918	14918	14918	14918	14850	14850	14850
Coal F-Factor	8598	8598	8594	8594	8594	8608	8608	8608
Flue Gas H_2O vapor, % by vol	7.4	5.0	6.6	7.9	5.4	6.5	7.1	6.3
Theoretical mg Hg/dscm	12.73	13.06	15.18	14.97	15.38	14.07	13.98	14.10
Calculated mg Hg/dscm	12.03	11.11	13.50	12.97	12.48	12.52	12.02	11.65
Measured mg Hg/dscm	13.45	8.46	12.79	11.71	9.60	12.35	11.71	11.60

Table A-32. Task 4 mercury comparisons.

Location Date Test Number	F 2/24/04 F-4-1	F 2/27/04 F-4-2	F 3/1/04 F-4-3
ppm Hg in Coal	0.11	0.11	0.12
Coal Btu/lb (Assumed)	14918	14918	14918
Coal F-Factor	8439	8598	8619
Flue Gas H_2O vapor, % by vol	7.3	8.4	8.0
Theoretical mg Hg/dscm	12.98	12.59	13.76
Calculated mg Hg/dscm	11.05	11.37	12.01
Measured mg Hg/dscm	11.64	9.66	12.20

Table A-33. Task 5 mercury comparisons.

Location	F	F	F
Date	3/24/04	3/25/04	3/25/04
Test Number	F-5-1	F-5-2	F-5-3
ppm Hg in Coal	0.11	0.11	0.11
Coal Btu/lb (Assumed)	14918	14918	14918
Coal F-Factor	8615	8737	8758
Flue Gas H_2O vapor, % by vol	7.8	8.4	9.0
Theoretical mg Hg/dscm	12.65	12.39	12.28
Calculated mg Hg/dscm	10.39	10.66	10.61
Measured mg Hg/dscm	11.47	11.83	11.67

Table A-34. Task 6 mercury comparisons.

Location	E	F	E	F	E	F
Date	4/1/04	4/1/04	4/13/04	4/13/04	4/13/04	4/13/04
Test Number	E-6-1	F-6-1	E-6-2	F-6-2	E-6-3	F-6-3
ppm Hg in Coal	0.09	0.09	0.11	0.11	0.11	0.11
Coal Btu/lb (Assumed)	14918	14918	14918	14918	14918	14918
Coal F-Factor	9684	8694	8352	8352	8286	8286
Flue Gas H_2O vapor, % by vol	9.9	9.6	8.6	10.4	8.7	10.6
Theoretical mg Hg/dscm	9.00	10.05	12.93	12.68	13.02	12.75
Calculated mg Hg/dscm	7.44	7.99	11.23	11.38	10.91	11.69
Measured mg Hg/dscm	8.79	8.96	11.73	9.37	8.45	10.18

Table A-35. Task 7 commencing tests mercury comparisons.

Location	F	F	F
Date	9/8/2004	9/9/2004	9/9/2004
Test Number	F-7-1	F-7-2	F-7-3
ppm Hg in Coal	0.109	0.141	0.12
Coal Btu/lb (Actual)	13639	13198	13225
Coal F-Factor	9796	9677	9684
Flue Gas H_2O vapor, % by vol	10.7	9.1	9.0
Theoretical mg Hg/dscm	11.68	16.08	13.67
Calculated mg Hg/dscm	11.33	13.03	10.48
Measured mg Hg/dscm	9.28	10.99	9.38

Table A-36. Task 7 concluding tests mercury comparisons.

Location	F	F	F
Date	12/15/04	12/15/04	12/16/04
Test Number	F-7-4	F-7-5	F-7-6
ppm Hg in Coal	0.101	0.119	0.121
Coal Btu/lb (Actual)	13043	13005	12990
Coal F-Factor	9873	9891	9950
Flue Gas H_2O vapor, % by vol	6.8	7.2	6.7
Theoretical mg Hg/dscm	11.72	13.76	14.00
Calculated mg Hg/dscm	10.64	11.70	10.97
Measured mg Hg/dscm	10.06	11.72	10.26

Table A-37. Task 7 concluding tests with humidification mercury comparisons.

Location Date Test Number	F 12/16/04 F-7-7	F 12/17/04 F-7-8
ppm Hg in Coal	0.096	0.10
Coal Btu/lb (Actual)	12876	13078
Coal F-Factor	10042	9835
Flue Gas H_2O vapor, % by vol	8.2	8.3
Theoretical mg Hg/dscm	10.92	11.43
Calculated mg Hg/dscm	8.31	8.94
Measured mg Hg/dscm	7.82	10.48

7.6.2. Particulate

The concentrations of particulate measured at locations upstream of the pilot ESP during each task were compared to theoretical concentrations, which were derived by applying the as-fired coal concentrations of ash to the coal heating value (Btu/lb), fuel F-factor (dry basis), and correcting for flue gas moisture.

A calculated value was not determined as the discrepancy between the calculated and measured particulate concentrations indicate the gas stream was not an accurate reflection of the plant flue gas.

The following tables summarize the comparisons of particulate concentrations.

Table A-38. Task 3 particulate comparisons.

Location	A	F	A	B	F	A	B	F
Date	12/17/03	12/17/03	1/29/04	1/29/04	1/29/04	1/29/04	1/29/04	1/29/04
Test Number	A-3-1	F-3-1	A-3-2	B-3-1	F-3-2	A-3-3	B-3-2	F-3-3
Percent Ash in Coal	12.27	12.27	12.27	12.27	12.27	12.22	12.22	12.22
Coal Btu/lb (Actual)	14918	14918	14918	14918	14918	14850	14850	14850
Coal F-Factor	8598	8598	8594	8594	8594	8608	8608	8608
Flue Gas H_2O vapor, % by vol	7.4	5.0	6.6	7.9	5.4	6.5	7.1	6.3
Theoretical lb/mscf	956.6	956.6	957.1	957.1	957.1	956.0	956.0	956.0
Theoretical PM gr/dscf	6.20	6.36	6.26	6.17	6.34	6.26	6.22	6.27
Measured PM gr/dscf	4.93	2.90	4.42	5.72	3.20	5.00	4.86	3.90

Table A-39. Task 4 particulate comparisons.

Location	F	F	F
Date	2/24/04	2/27/04	3/1/04
Test Number	F-4-1	F-4-2	F-4-3
Percent Ash in Coal	13.63	12.84	12.78
Coal Btu/lb (Actual)	14918	14918	14918
Coal F-Factor	8439	8598	8619
Flue Gas H_2O vapor, % by vol	7.3	8.4	8.0
Theoretical lb/mscf	1082.7	1001.1	993.9
Theoretical PM gr/dscf	7.03	6.42	6.40
Measured PM gr/dscf	3.67	2.81	3.68

Table A-40. Task 5 particulate comparisons.

Location	F	F	F
Date	3/24/04	3/25/04	3/25/04
Test Number	F-5-1	F-5-2	F-5-3
Percent Ash in Coal	11.21	10.43	9.75
Coal Btu/lb (Actual)	14918	14918	14918
Coal F-Factor	8615	8737	8758
Flue Gas H_2O vapor, % by vol	7.8	8.4	9.0
Theoretical lb/mscf	872.2	800.2	746.3
Theoretical PM gr/dscf	5.63	5.13	4.75
Measured PM gr/dscf	2.75	2.59	2.74

Table A-41. Task 6 particulate comparisons.

Location	E	F	E	F	E	F
Date	4/1/04	4/1/04	4/13/04	4/13/04	4/13/04	4/13/04
Test Number	E-6-1	F-6-1	E-6-2	F-6-2	E-6-3	F-6-3
Percent Ash in Coal	9.33	9.33	9.38	9.38	9.55	9.55
Coal Btu/lb (Actual)	14918	14918	14918	14918	14918	14918
Coal F-Factor	9684	8694	8352	8352	8286	8286
Flue Gas H_2O vapor, % by vol	9.9	9.6	8.6	10.4	8.7	10.6
Theoretical lb/mscf	645.8	719.4	752.8	752.8	772.6	772.6
Theoretical PM gr/dscf	4.07	4.55	4.82	4.72	4.94	4.83
Measured PM gr/dscf	1.88	2.68	3.14	2.18	1.96	2.37

Table A-42. Task 7 commencing tests particulate comparisons.

Location	F	F	F
Date	9/8/2004	9/9/2004	9/9/2004
Test Number	F-7-1	F-7-2	F-7-3
Percent Ash in Coal	8.88	11.45	11.75
Coal Btu/lb (Actual)	13639	13198	13225
Coal F-Factor	9796	9677	9684
Flue Gas H_2O vapor, % by vol	10.7	9.1	9.0
Theoretical lb/mscf	664.6	896.5	917.5
Theoretical PM gr/dscf	4.15	5.70	5.84
Measured PM gr/dscf	3.43	3.58	2.68

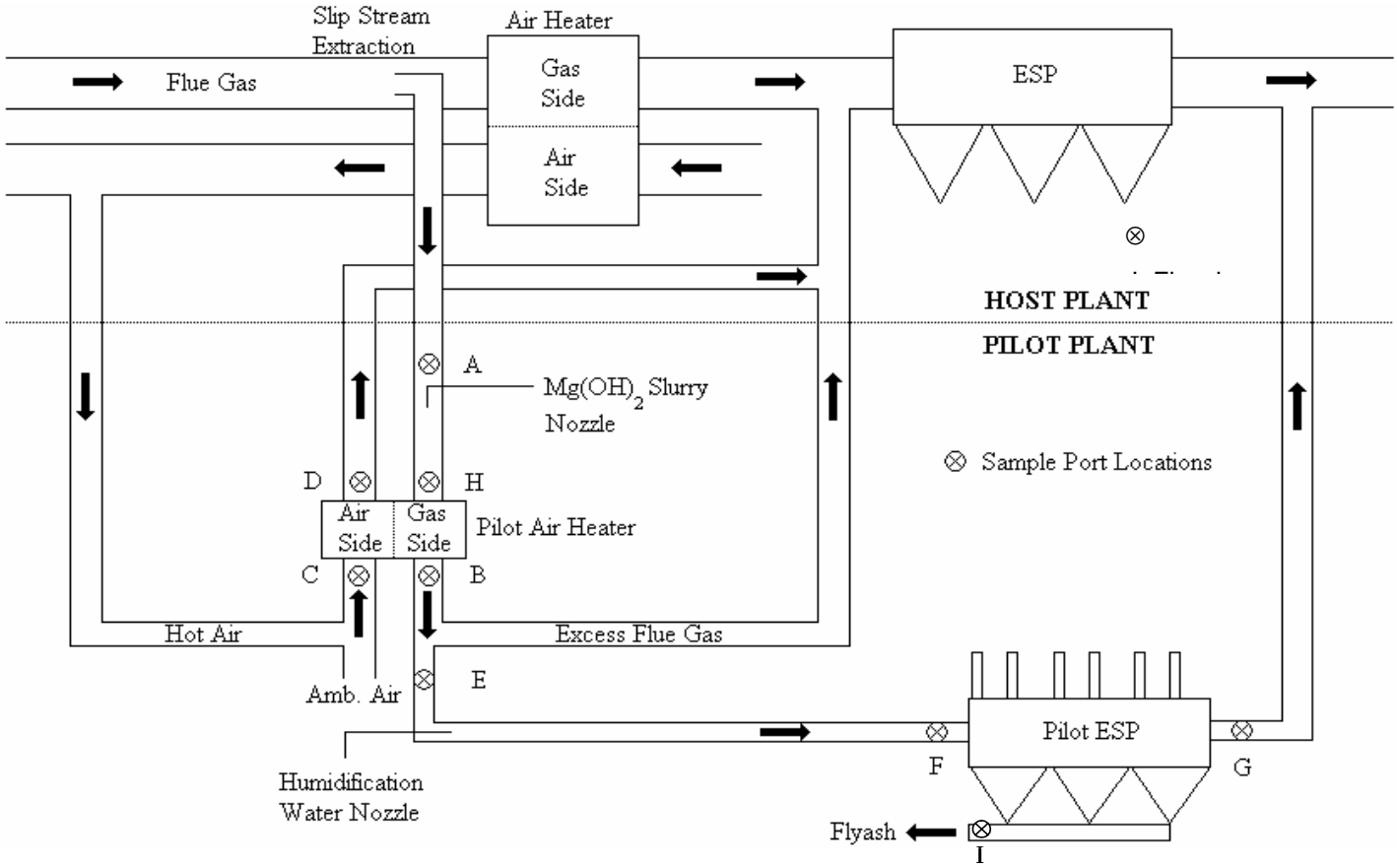
Table A-43. Task 7 concluding tests particulate comparisons.

Location	F	F	F
Date	12/15/04	12/15/04	12/16/04
Test Number	F-7-4	F-7-5	F-7-6
Percent Ash in Coal	12.15	12.21	12.63
Coal Btu/lb (Actual)	13043	13005	12990
Coal F-Factor	9873	9891	9950
Flue Gas H_2O vapor, % by vol	6.8	7.2	6.7
Theoretical lb/mscf	943.5	949.2	977.2
Theoretical PM gr/dscf	6.16	6.17	6.38
Measured PM gr/dscf	4.41	4.75	3.81

Table A-44. Task 7 concluding tests with humidification particulate comparisons.

Location Date Test Number	F 12/16/04 F-7-7	F 12/17/04 F-7-8
Percent Ash in Coal	13.2	11.94
Coal Btu/lb (Actual)	12876	13078
Coal F-Factor	10042	9835
Flue Gas H_2O vapor, % by vol	8.2	8.3
Theoretical lb/mscf	1020.9	928.3
Theoretical PM gr/dscf	6.56	5.96
Measured PM gr/dscf	3.00	3.88

Figure 1. Schematic of Pilot Plant and Sampling Locations



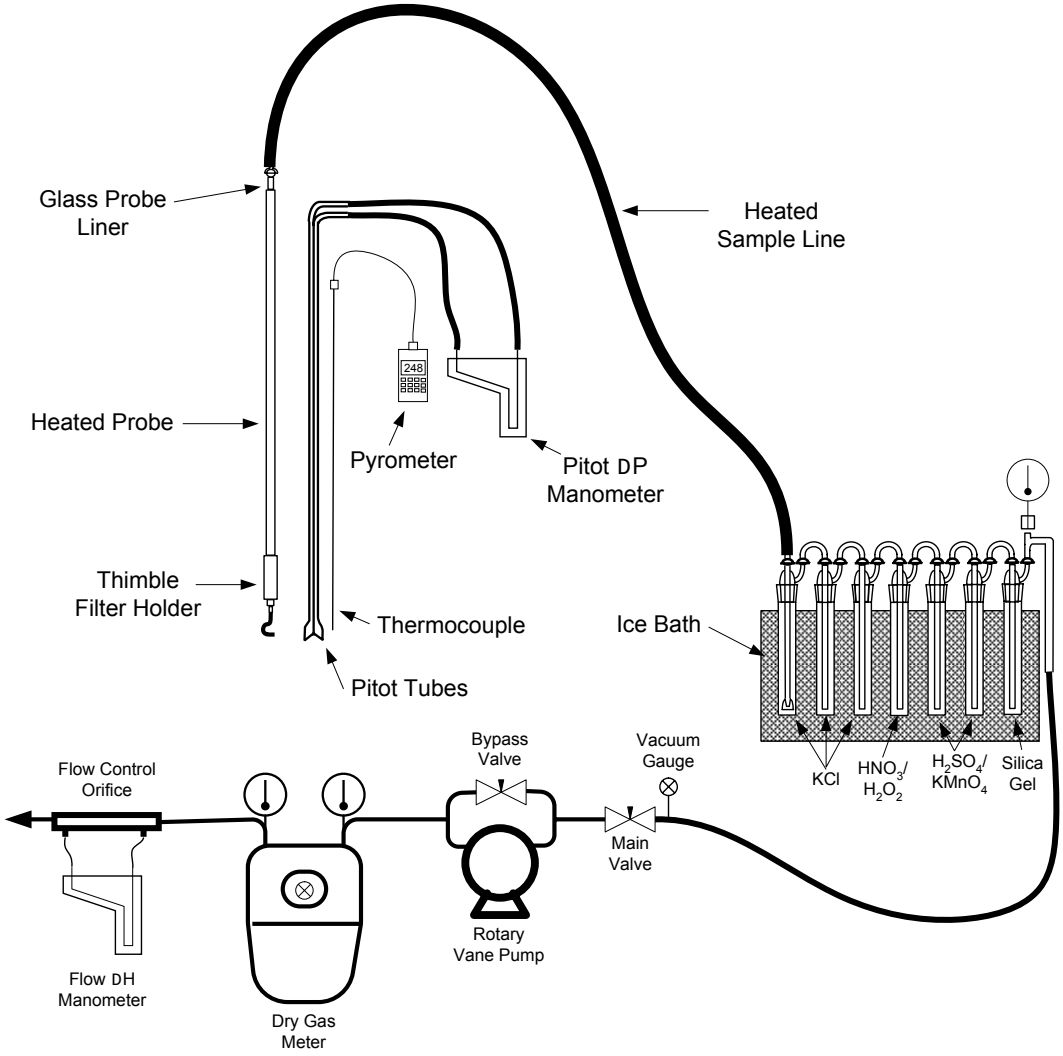


Figure 2. Schematic of the Ontario Hydro train in a Method 17 configuration.

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Appendix A

Task 3, 4, 5, 6, 7 Coal Analysis

Analytical Number	Sample Number	Date	Description	As Det. Moisture	ASH	C	S	CL	As Det. Hg	SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	P2O5	SO3
				%	(dry)%	(dry)%	(dry)%	(dry)%	ppm	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%	(dry)%
			Task 3																
20032915	5	9/18/03	Station Coal	1.93	12.12	72.50	3.67		0.11										
20033000	7	9/25/03	Station Coal	1.49	13.71	71.88	3.66	0.071	0.09										
20033019	10	9/26/03	Station Coal	1.58	14.35	72.18	3.24	0.008	0.09										
20033055	12	9/29/03	Station Coal	1.46	14.27		3.32	0.072	0.10										
20033087	14	9/30/03	Station Coal	1.44	13.25		3.61	0.073	0.13										
20033115	16	10/1/03	Station Coal	1.57	15.23	70.99	3.30	0.007	0.11										
20033198	18	10/2/03	Station Coal	1.27	13.71		3.32	0.067	0.12										
20033217	20	10/3/03	Station Coal	1.37	13.99		3.42	0.066	0.13										
20033252	22	10/6/03	Station Coal	1.52	14.15		3.43	0.069	0.12										
20033291	24	10/7/03	Station Coal	1.66	15.30		3.22	0.061	0.11										
20040214	26	12/17/03	Station Coal	1.46	13.43		3.28	0.055	0.11										
20040215	31 & 33	12/19/03	Station Coal	1.54	14.56		3.22	0.061	0.12										
20040367	30	1/29/03	Station Coal	1.68	12.27	72.80	3.23	0.071	0.13										
20040368	31	1/29/03	Station Coal	1.66	12.22	72.74	3.20	0.073	0.12										
20040473	36	1/20/04	Station Coal	1.37	13.63		2.78	0.067	0.16										
20040474	28	1/21/04	Station Coal	1.37	14.79		2.76	0.062	0.14										
			Task 4																
20041412	39	2/24/04	Station Coal	1.08	13.63	71.45	2.99	0.090	0.11										
20041413	43	2/27/04	Station Coal	1.25	12.84	72.73	3.16	0.080	0.11										
20041414	48	3/1/04	Station Coal	1.23	12.78	72.88	3.21	0.070	0.12										
20041415	51	3/2/04	Station Coal	1.17	11.18	73.70	3.13	0.070	0.11										
20041416	52	3/2/04	Station Coal	1.10	13.37	71.66	3.36	0.070	0.12										
20041417	54	3/3/04	Station Coal	1.21	13.37	72.66	2.99	0.080	0.10										
20041418	55	3/3/04	Station Coal	1.18	13.60	72.21	3.11	0.070	0.13										
			Task 5																
20041589	58	3/24/04	Station Coal	1.78	11.21	72.73	4.14	0.060	0.11										
20041594	65	3/25/04	Station Coal	1.80	10.43	73.72	4.35	0.070	0.11										
20041595	66	3/25/04	Station Coal	1.88	9.75	74.08	4.26	0.060	0.11										
			Task 6																
20041727	71	4/1/04	Station Coal	1.73	9.33	73.79	4.08	0.050	0.09										
20041862	75	4/13/04	Station Coal	2.16	9.38	70.90	4.66	0.050	0.11										
20041863	80	4/13/04	Station Coal	2.11	9.55	70.32	4.78	0.060	0.11										
			Task 7																
20045001	97	09/02/04	Station Coal	1.33	9.92	75.73	3.13	0.090	0.11	45.72	21.76	0.90	19.65	4.07	0.89	0.86	1.97	0.49	3.56
20045002	102	09/03/04	Station Coal	1.28	8.47	77.23	3.16	0.090	0.10	41.87	20.37	0.87	22.95	4.94	0.89	1.04	1.59	0.51	4.82
20045003	105	09/08/04	Station Coal	1.37	8.88	76.93	3.22	0.090	0.11	42.61	20.80	0.88	22.60	4.23	0.83	0.85	1.77	0.52	3.72
20045004	109	09/09/04	Station Coal	1.41	11.45	73.81	3.24	0.080	0.14	46.36	22.18	0.93	20.64	3.04	0.82	0.66	2.18	0.42	2.66
20045005	114	09/09/04	Station Coal	1.43	11.75	73.85	2.97	0.070	0.12	47.77	23.02	0.96	17.76	3.14	0.87	0.63	2.20	0.33	2.88
20050027	122	12/09/04	Station Coal	1.96	10.11		4.52	0.053	0.10	41.67	19.81	0.91	29.50	2.43	0.70	0.47	1.57	0.19	2.54
20050028	126	12/10/04	Station Coal	1.80	10.60		4.20	0.052	0.11	42.69	20.59	0.96	27.33	2.64	0.72	0.49	1.62	0.21	2.74
20050029	129	12/10/04	Station Coal	1.77	10.45		4.21	0.051	0.11	43.80	20.97	0.99	26.34	2.61	0.72	0.47	1.66	0.23	2.67
20050030	134	12/15/04	Station Coal	1.63	12.15		3.34	0.057	0.10	48.67	22.62	1.07	19.75	2.68	0.80	0.52	1.99	0.26	2.91
20050031	137	12/15/04	Station Coal	1.47	12.21		3.18	0.057	0.12	48.83	23.33	1.10	18.07	2.47	0.81	0.55	2.04	0.26	2.66
20050032	142	12/16/04	Station Coal	1.59	12.63		3.59	0.057	0.12	47.52	23.17	1.07	20.43	2.19	0.77	0.53	1.98	0.24	2.54
20050033	146	12/16/04	Station Coal	1.73	13.20		3.38	0.063	0.10	46.29	21.66	1.00	18.75	4.33	0.79	0.51	1.93	0.21	4.75
20050034	150	12/17/04	Station Coal	1.71	11.94		3.29	0.053	0.10	47.75	22.56	1.05	19.53	2.67	0.80	0.54	1.96	0.26	3.02
20050036	154	12/22/04	Station Coal	1.77	10.10		4.69	0.053	0.10	41.08	18.99	0.88	28.94	3.06	0.68	0.58	1.53	0.19	2.88

APPENDIX B

CONSTRUCTION, OPERATION AND MAINTENANCE OF MULTI-POLLUTANT EMISSION CONTROL PILOT PLANT AT AE MITCHELL POWER STATION

Introduction

The Multi-Pollutant Emission Control Pilot Plant at the Allegheny Energy (AE) Mitchell Power Station includes a pilot-scale air heater with upstream alkaline sorbent injection and a pilot electrostatic precipitator (ESP) collection system with upstream water injection. The pilot plant is used for the evaluation of mercury (Hg) control techniques at lowered flue gas temperatures. The pilot plant operates on a slip-stream of flue gas taken upstream of the host station air heater (~700 °F) of the Allegheny Energy 285 MW Mitchell Unit 3 coal-fired power plant. The host power plant typically burns an eastern bituminous coal with a nominal sulfur concentration of 3.5% and a nominal chlorine concentration of 0.1%. The flue gas and air circulated through the pilot plant are returned to the station ductwork.

The pilot plant is designed to simulate the cold-end components of many coal-fired utility systems currently operating in the U.S. The pilot plant consists of isolation valves, insulated piping, alkaline sorbent ($Mg(OH)_2$) feed system, regenerative (Ljungstrom) air heater, fans, water injection system, 1800 scfm pilot ESP, monitoring instrumentation, and computer control system. A schematic of the pilot plant is shown in Figure B-1 and the process flow drawings, Figures B-2 and B-3.

The flue gas to the pilot plant is taken from the ductwork immediately upstream of the station air heater. The flue gas is delivered to a pilot scale Ljungstrom-type air heater with a rated capacity of ~16,500 lb/hr or ~3,500 scfm of air. A suspended slurry of $Mg(OH)_2$ and water can be injected into the flue gas upstream of the pilot air heater during low exit temperature (below 300°F) operation. The $Mg(OH)_2$ neutralizes the sulfur trioxide (SO_3) in order to prevent sulfuric acid condensation in the air heater. The flue gas passes through the pilot heater, in which the heat exchange occurs. Automatic controls vary the supply of cooling air (typically the combustion air side of the air heater) to produce a range of desired flue gas temperatures for the Hg removal study. The air from the pilot air heater is returned to the station flue gas ductwork.

A portion of the flue gas exiting the pilot air heater is delivered to a 1800 scfm pilot-scale ESP. Water spray cooling upstream of the pilot ESP can be used to determine if additional water vapor and lower flue gas temperatures (as low as 190 °F) are beneficial to Hg removal and ESP performance. The exit gas from the pilot ESP is reinjected into the station flue gas ductwork.

Pilot Plant Description

The primary schematics, diagrams, layout drawings and equipment lists used to engineer, construct and operate the pilot plant are listed below.

Figure #	Description
B-1	Schematic of Pilot Plant
B-2	Process Flowsheet, Maximum Flows
B-3	Process Flowsheet, Minimum Flows
B-4	$Mg(OH)_2$ Slurry Area, P&I Diagram
B-5	Pilot Air Heater Area, P&I Diagram
B-6	Pilot ESP Area, P&I Diagram
B-7	General Arrangement & Piping, Plan View
B-8	General Arrangement & Piping, Enlarged Plan View
B-9	General Arrangement & Piping, Section Views
B-10	General Arrangement & Piping, Enlarged Plan & Section Views
B-11	General Arrangement & Piping, Enlarged Section View
B-12	General Arrangement & Piping, Enlarged Plan & Section Views
B-13	General Arrangement, Enlarged Plan View of $Mg(OH)_2$ Area
B-14	Assembly, Temperature Controlled Corrosion Probe
B-15	Process Display Screen, Slurry Prep Area
B-16	Process Display Screen, Air Heater Area
B-17	Process Display Screen, ESP Area
B-18	Process Controller Screen
B-19	Process Data Transfer Screen
B-20	Project Timetable

Table #	Description
B-1	Major Equipment List
B-2	Instrument List
B-3	Design engineering and Construction – Task 1
B-4	Start Up and Maintenance – Task 2
B-5	Pilot Plant Operation – Task 3
B-6	Pilot Plant Operation – Task 4, 5, 6
B-7	Pilot Plant Operation – Task 7
B-8	Corrosion Probe & Coupon Operation at ESP Inlet and Outlet

The pilot plant is divided into three areas; 100 - $Mg(OH)_2$ Slurry, 200 - Pilot Air Heater and 300 - Pilot ESP. The piping and instrument (P&I) diagrams (Figures 4, 5 and 6) show the details of the pilot plant areas.

The 100 - $Mg(OH)_2$ Slurry Area includes pumps, concentrated and diluted slurry tanks, mixer, filter, weighing system and water supply to first dilute concentrated slurry to 0.5 to 8% solids and then to deliver dilute slurry to a metering pump and flowmeter which feeds a spray nozzle located in a 20” pipe at the 200 - Pilot Air Heater Area.

Photo 1-B. Dilute Slurry Day Tank with Agitator, Circulation Pump and Filters

Photo 2-B. Metering Pump and Flowmeter Enclosure with 20" Flue Gas Extraction Tie-In in Background

The 200 - Pilot Air Heater Area includes 20" power station extraction duct tie-in, piping, fans and valves to deliver 500-700 ^{0}F flue gas from the Mitchell Station and ambient air to the Ljungstrom-type air heater, where the flue gas is cooled to 220 $^{\circ}$F to 300 $^{\circ}$F, and the air is heated to a maximum of 570 $^{\circ}$F. Excess flue gas and hot air from the pilot air heater are returned to Mitchell Station ductwork through the 20" tie-in.

Photo 3-B. Ljungstrom-Type Pilot Air Heater (Before Installation)

Photo 4-B. Flue Gas By-Pass Fan with Tee-In for Pilot ESP Gas, Pilot Air Heater in Tower Behind

The 300 - Pilot ESP Area includes piping, water spray, ESP and fan to bring a portion of the cooled flue gas from the 200 – Pilot Air Heater Area to remove the flyash and to further cool the flue gas to as low as 190 ^{0}F with a water spray. All flue gas and flyash from the pilot ESP are returned to Mitchell Station ductwork through the 10” tie-in.

Photo 5-B. Pilot ESP

Photo 6-B. Gas ID Fan and Pilot ESP

All major process flow control, start up and shutdown were performed through the automatic control system. The control system includes a programmable logic controller

(PLC) and computer connected to the PLC. A remote PLC is also located in the 100 - $Mg(OH)_2$ Slurry Area, and is connected to the main PLC. The main PLC and computer are in the control room trailer near the pilot plant. The computer is remotely accessible via modem.

Photo 7-B. Control Room Trailer

100 - $Mg(OH)_2$ Slurry Area

This area includes 400-gallon bulk containers (T-101) and a transfer/circulation pump (P-105) for concentrated slurry handling, a 65 gallon weigh tank/scale for slurry dilution with water, a 360 gallon agitated day tank (T-102), and circulation pump (P-108) to feed slurry to the metering pump (P-106). The metering pump delivers slurry to a two fluid spray injection nozzle (X-202). This eqipment is shown in Figures B-2, B-3, B-4, B-13, B-15, and Tables B-1, and B-2.

The concentrated (17-20%) $Mg(OH)_2$ slurry is transported in six to eight separate 400-gallon bulk containers (T-101) from the Allegheny Energy Pleasants Station near Parkersburg, WV, to Mitchell Station. Each 400-gallon bulk container is set in place with a fork truck and connected to an air-operated 2" diaphragm pump (P-105), which mixes the slurry and delivers slurry to a 65-gallon weigh tank (T-104). The concentrated slurry is diluted with water to 0.5 to 8% solids in the weigh tank and then delivered to a 360-gallon day tank (T-102). The operation of the diaphragm pump and weigh tank valving are started and stopped by the PLC (WIC-101) that monitors the day tank level (LT-103). The weight of water and concentrated slurry are entered at the computer.

The 360-gallon day tank (T-102) holding the dilute slurry includes an agitator (A-103), which is started/stopped via a hand switch. The day tank discharges to a 2.5-gpm

circulation pump (P-108) operated by a hand switch. The dilute slurry from the circulation pump is filtered (F-107) to remove particles larger than 1/16" and delivered to a variable-speed, progressive-cavity metering pump (P-106) located near the spray nozzle. The metering pump flow rate is always a constant 0.25 gpm of slurry regardless of concentration. The concentration of the dilute slurry is adjusted between 0.5 to 8% solids to deliver the desired amount of $Mg(OH)_2$. The mass flow rate varies depending on the concentration of the slurry, which is entered into the computer. The metering pump speed is controlled through the PLC, which is set to maintain a signal from a coriolis type mass flow meter (FE-107). The mass flow meter also monitors density of the slurry. Excess slurry circulated to the metering pump is returned to the day tank.

This equipment is only in operation when the pilot air heater is set to cool the flue gas below 300 °F. When in operation, the agitator and circulation pump run continuously; the day tank is refilled automatically; the metering pump starts and stops with the pilot air heater; and the 400-gallon bulk container is emptied over a five- to seven-day period.

200 – Pilot Air heater Area

This area includes: 20" to 8" piping to transport flue gas and air to and from the pilot-scale Ljungstrom-type air heater supplied by Alstom Power Inc.; a gas by-pass fan (B-208) to extract hot flue gas from the station ductwork and to return the cooled flue gas to the station ductwork; and an air ID fan (B-207) to draw air through the air side of the air heater and discharge air to the station ductwork. Control valves and variable speed fans are used to control the flue gas and airflow rates and temperatures. This equipment is shown in Figures B-1, B-2, B-5, B-7 - B-11, B-16, and in Tables B-1 and B-2.

Flue gas is extracted from station ductwork through a 20" pipe and drawn through the flue gas side of the pilot air heater at a selected constant mass flow rate of 16,500 to 8,550 lb/hr at temperatures of 500 to 700 °F with the gas bypass fan (B-208) driven by a variable speed motor. The extracted mass flow is measured using a thermal dispersion type meter (FE-206). The mass flow, entered into the computer, is maintained by varying the speed of the gas bypass fan (B-208) through a motor speed controller, which receives a signal from the PLC. The temperature (TIT-205), mass flow (FE-206), and pressure (PIT-227) of the extracted flue gas and the flow rate (FE-222) of the cooled flue gas are recorded.

The pressure drop across the flue gas side of the pilot air heater is measured (DPIT-212) and recorded for transmission to the power station control room, where a high alarm light indicates the need to sootblow the pilot air heater. With a hand switch the station operator initiates the opening of valve (FV-213) to deliver 200-psig air at 1284 scfm to the manifold on the pilot air heater for a period of one minute. Alarms, sootblowing and recording of the pressure drop are performed through the PLC and the computer connected to the PLC.

The differential pressure between flue gas and air on the cold end (bottom) of the pilot

air heater is measured (DPIT-216) and maintained at a selected constant value of 1.8”wc to 0.5”wc through the PLC. The air is maintained at a lower pressure than the flue gas at all times. The PLC adjusts the position of a control valve (DPV-216) at the ambient air inlet in order generate pressure drop. The desired differential pressure is entered at the computer.

The inlet air temperature is maintained by mixing hot air from the station through control valve (TCV-215) with the ambient air. The air temperature is measured (TIT-215) and maintained at a selected set point of 74 °F to 148 °F through the PLC, which adjusts the position of the control valve (TCV-215). As the ambient air temperature rises above the selected constant set point, the control valve will close completely. The inlet air temperature is entered at the computer.

The inlet air is drawn through the air side of the pilot air heater by the air induced draft (ID) fan (B-207) driven by a variable-speed motor. The mass flow rate of air through the air heater controls and maintains the exit flue gas temperature at a constant value between 225 and 300 °F. The plant operator enters into the computer the desired set point for TIC-223. The temperature controller, through the PLC, adjusts the airflow rate to achieve the desired flue gas outlet temperature. The inlet air mass flow rate (FT-217) and outlet air temperature (TIT-219) are recorded.

The bearing cooling water, monitored by a flow switch (FSL-209) set at 3 gpm will shut down the pilot plant if water flow is reduced. The water flow rate is adjusted by changing the setting on the pressure control valve (PVC-228) and the globe valve. The bearing temperature (TE-210) is monitored and alarmed at 140 °F.

The air heater variable speed drive control (SC-230) is adjusted locally from 20 to 100%. The drive is monitored by the PLC.

The slurry is injected with a two-fluid spray nozzle mounted inside the 20” pipe. The compressed air flow to the nozzle is adjusted locally at the pressure control valve (PCV-226) to operate at 40 to 60 psig. The slurry is pumped to the nozzle by the metering pump (P-106). When the pilot plant shuts down, the compressed air stays on. The metering pump is stopped by the PLC.

The instrument air purge rotometers (FI-211A and FI-211B) are set to continuously deliver 1 scfh to prevent flyash accumulation in the pressure sensing lines.

300 – Pilot ESP Area

This area includes: 10” to 8” insulated piping to transport flue gas to and from the pilot scale electrostatic precipitator (ESP) supplied by Environmental Elements Corp. (EEC); gas ID fan (B-305) to extract cooled flue gas from the 200 – Pilot Air Heater Area and to discharge flue gas into station ductwork; potable water booster pump (P-302) to deliver high pressure water to a two-fluid water spray nozzle (X-302) for further flue gas cooling; temperature controlled corrosion probe (H-310, P-309); corrosion coupons; and

blower/eductor to transport flyash from the ESP to the station ductwork. This equipment is shown in Figures B-1, B-2, B-3, B-6, B-7, B-9, B-12, B-17, and in Tables B-1 and B-2. The temperature-controlled corrosion probe is shown in Figure B-14.

The flue gas is drawn from the discharge of the gas bypass fan (B-208) in the pilot air heater area by the gas ID fan (B-305) driven by a variable speed motor controlled by a signal from the PLC. The constant mass flow rate is selected at the computer to be 2801 to 5603 lb/hr at temperatures of 225 to 300 °F. The mass flow is measured using a thermal dispersion type meter (FT-302) and monitored by the PLC. The inlet flue gas temperature (TIT-301) and mass flow (FT-302) are recorded. The flue gas is returned to the station duct through valve FV-327A.

The water is injected with a two-fluid spray nozzle mounted inside the 10" pipe to cool the flue gas from 300 °F or less, to as low as 190 °F. The water flow rate, adjusted by a control valve (FV-304) receives a signal from the PLC that is set to maintain a constant temperature as low as 190 °F. The water flow rate (FT-309) is recorded. The water flow is not turned on (FV-320) until the flue gas warms the ESP and piping. During startup, the ESP outlet flue gas temperature (TE-320) must reach 275 °F before the water is turned on (FV-320). The compressed air flow to the nozzle is adjusted locally at the pressure control valve (PCV-328) to operate at 70 to 80 psig. When the pilot plant shuts down the compressed air stays on. The water flow is shutdown on low compressed air pressure (PSL-310) set at the instrument.

The inlet flue gas pressure (PIT-319) is monitored and recorded. If the pressure drops to negative 20" wc, the ESP area is shut down by the PLC. The pressure setting is entered at the computer.

A screw conveyor transports the flyash collected by the ESP to an eductor. The eductor, using motive air from a blower (B-306), pneumatically conveys the flyash to an 8" flue gas return line. The screw conveyor drive is operated by a hand switch on the local pilot ESP control panel and monitored by a zero-speed switch on the drive shaft, which shuts down the ESP area at zero speed. The discharge pressure of the blower is measured (PIT-318). The ESP area is shutdown if discharge pressure is too low and alarmed if too high. Pressure settings are entered at the computer.

The pilot ESP area is operated independently of the pilot air heater area. The gas bypass valve (FV-232) is closed and opened with operation of the pilot ESP. The operation of the pilot ESP area is designated at the computer. All pilot ESP start/stop, high voltage power control and monitoring are performed locally.

The temperature-controlled corrosion probe located at the pilot ESP inlet consists of a metal coupon attached to a liquid (propylene glycol - water) cooled jacket that is mounted through a 4" opening in the 10" pipe. The coupon temperature is monitored by a thermocouple (TE-306). On start up, the liquid is heated (H-310) to maintain a temperature setting of 140 to 150 °F at the coupon. After flue gas flow is established the temperature is maintained by heat loss from the bare piping. The heater only

operates if losses are too high. The temperature setting for the coupon is entered at controller (TIC-306) on a local panel. The circulation pump (P-309) and heater (H-310) are operated by hand switches on the local panel. The corrosion probe is operated independently of the pilot ESP and can remain in operation during short pilot ESP shutdowns.

Instrumentation and Control System

All major process flow control, equipment start up, and shutdown are performed through the automatic control system. Some operations are performed locally at the tie-in or equipment. The automatic control system includes a programmable logic controller (PLC) and computer connected to the PLC. The PLC and software to operate the PLC were purchased from Allen-Bradley. A remote PLC is also located in the 100 - $Mg(OH)_2$ Slurry Area, and is connected to the main PLC. The main PLC and computer are in the control room trailer near the pilot plant. The computer is remotely accessible via modem.

The computer and monitor to enter and review data included the following:

- Alarms (On Process Display)
- Process Display Screens (Figures B-15 - B-17)
- Process Controller Screens (Figure B-18)
- Entry of Set Points (Figure B-18)
- Data Transfer Screen and Data Logging (Figure B-19)

The following data are logged In an Excel Spreadsheet and stored for transfer via phone line.

- FIC-107 Dilute Slurry Mass Flow, Spray Nozzle
- DI-107 Dilute Slurry Density, Spray Nozzle
- FT-206 Extracted Flue Gas Mass Flow
- FT-222 Cooled Flue Gas/Air Heater Outlet Mass Flow
- FT-217 Air Heater Inlet Air Mass Flow
- FT-302 ESP Inlet Mass Flow
- FT-309 Water Mass Flow, Spray Nozzle
- TIT-205 Extracted Flue Gas Temperature
- TIT-223 Cooled Flue Gas/Air Heater Outlet Temperature
- TIT-215 Air Heater Inlet Air Temperature
- TIT-219 Air Heater Outlet Air Temperature
- TIT-301 ESP Inlet, Upstream Temperature
- TIT-304 ESP Inlet, Downstream Temperature
- TIT-320 ESP Outlet Temperature
- TIT-306 Corrosion Probe Temperature
- PIT-227 Extracted Flue Gas Pressure
- DPIT-212 Air Heater Gas Side Diff. Pressure
- DPIT-216 Air Heater Cold End Diff. Pressure
- PIT-319 ESP Inlet, Downstream Pressure

The instruments connected to the PLC for data logging and automatic control are described on the Instrument List shown in Table 2.

Construction, Operation, and Maintenance of Pilot Plant

Program Timetable

The Program Timetable is shown in Figure B-20.

Design, Engineering, and Construction (Task 1)

Major milestones completed during Task 1 are shown in Table B-3. A description of the activities completed during Task 1 follows below.

Task 1 Activities - October 5, 2001 thru February 28, 2002

Beginning in November, frequent meetings were held with Allegheny Energy personnel at Mitchell Station to develop plans and gather information for the pilot plant installation. Allegheny's outage coordinator was involved in some of these meetings to make sure that the pilot plant construction was coordinated with the planned outage at Mitchell Station. Close interaction with Alstom Power regarding the design of the air heater was initiated once their subcontract was placed in mid-December. A description of the progress on the process design and construction engineering aspects of the project follows.

The Pennsylvania Department of Environmental Protection determined that this project is exempt from Plan Approval/Operating Permit requirements, and so notified Allegheny via letter on November 29, 2001. The only remaining environmental safety and health (ES&H) approvals required to proceed with the project are internal to the CONSOL and Allegheny organizations.

An engineering and construction schedule was completed. Preliminary equipment list, instrument list, process control and start/stop list, flow sheet, P&I and layout drawings were developed and drafted, and updated as needed.

Calculations on pilot air heater flue gas and air flowrates, temperatures, and pressures were completed by Alstom. Flow sheets showing maximum and minimum gas flow rates were developed. Ductwork sizes and pressure drops were calculated and updated as additional information was made available from Alstom. The flowsheets for the pilot plant were finalized. Figure B-2 represents maximum flow, and Figure B-3 represents minimum flow.

Flue gas velocity, temperature and static pressures at the Mitchell Station air heater inlet duct were measured by CONSOL on January 7, 2002. These measurements were made to select the location of the duct penetration for flue gas extraction.

An engineering services scope of work was formulated for the entire design project. A survey of candidate engineering companies was conducted with input from Allegheny Energy. Separate interviews were held in January 2002 with three engineering firms in

order to bid the preparation of preliminary general arrangement drawings of the pilot plant, and S/D Engineers was selected for that job. S/D Engineers completed the preliminary general arrangement drawing of the air heater and ESP pilot plant areas in February 2002. The final general arrangement drawings are shown in Figures B-7 - B-12.

A request for quotes for the design work, including preparing design drawings and specifications for purchase of materials and construction services, was sent to the same three engineering firms. The bid package included the preliminary general arrangement drawings of the air heater and ESP pilot plant areas, mechanical equipment list, instrument list and P&I drawings. Orbital Engineering's bid was selected, and a purchase order was issued in mid-March.

A layout drawing shown in Figure B-13, of the magnesium hydroxide slurry handling area was completed. Plans were formulated for transportation of the concentrated slurry from Pleasants Station and its on-site storage at Mitchell Station.

Alstom and Environmental Elements were asked to review the general arrangements and process controls for the pilot air heater and pilot ESP, respectively.

Mechanical specifications and requests for quotations were sent to vendors for the three fans needed for the pilot plant; i.e., the air ID fan, the gas ID fan, and the gas by-pass fan. The bids were evaluated and a purchase order for the three fans was issued to American Fan.

A survey of spray nozzle suppliers was completed. Mechanical specifications and requests for quotations were sent to vendors for the water and slurry spray nozzles. The bids were evaluated and a purchase order was issued to Lechler.

Environmental Elements provided electrical and general arrangement drawings for the pilot ESP. Information on the pilot ESP data collection and operating requirements was also received from them.

Task 1 Activities - March 1, 2002 thru August 31, 2002

Allegheny raised the unanticipated concern that the subsoil conditions in the planned location of the sixty-foot support structure for the pilot air heater may be unstable. Orbital Engineering conducted an investigation of subsoil conditions at that location and reviewed records and information provided by Allegheny. Orbital recommended the use of a four-foot thick spread concrete footer for the foundation. Neither the subsoil evaluation nor the robust foundation was anticipated.

General arrangement drawings of the pilot air heater, pilot electrostatic precipitator, and magnesium hydroxide slurry handling system areas were finalized. Flowsheets, P&I drawings, detailed piping and transition drawings, electrical drawings, foundation/ structural drawings, detailed equipment drawings mechanical equipment list, instrument list, process control list, and start/stop sequence list were completed for construction.

Sampling port layout drawings were made for each of the seven gas sampling locations.

The process logic controller (PLC) hardware was purchased through Applied Control Systems. A draft functional operation and control specification was delivered to Orbital Engineering to allow them to program the PLC. Orbital started the PLC programming for completion in September 2002.

The corrosion probe was designed and assembly and detail drawings were completed. Materials were ordered for the fabrication of the corrosion probe, and the related heater, pump, control panel, and glycol were purchased.

Some of the additional equipment and services purchased this period included:

- structural steel, knife gate valves and pipe fittings for the tie-ins and fabrication of the tie-in pipe
- pipe fittings for the water spray and slurry spray nozzle lances
- gas flow conditioners
- expansion joints
- slurry tanks, slurry pumps, and slurry valves
- weighing equipment
- fly ash sampling and pneumatic transport equipment
- sample port valves
- chute work
- instrumentation
- prefabrication of structural steel for the pilot plant
- prefabrication of large piping and transitions
- prefabrication of steel platforms for skid mounting of tanks and pumps

Alstom delivered the pilot air heater to Mitchell Station on March 20. Environmental Elements delivered the pilot electrostatic precipitator to Mitchell Station on May 22. Duct penetrations and installation of tie-in pipe and knife gate valves at Mitchell Station were completed on May 22 during a planned outage of the station, which lasted from April 15 through the first week of June.

Allegheny confirmed the availability of compressed air and water of appropriate quantity, quality, and accessibility for operation of the pilot plant.

Carmeuse verified that it would be acceptable to take magnesium hydroxide slurry in lots of 3,200 gal. This will allow CONSOL to load one truck at a time, as needed, carrying eight 400-gal tanks, rather than shipping the slurry by tanker and storing large quantities at the pilot plant. This obviated the need for a large-volume storage tank at the pilot plant.

Task 1 Activities - September 1, 2002 thru February 18, 2003

CONSOL and Allegheny Energy prepared the General Labor Specification, the Pilot Plant Construction Specification, and a request for quotes for the main pilot plant

construction job. A pre-bid meeting was held at Mitchell Station on September 4 with prospective construction contractors. Approximately 25 people representing six contractors and several of their subcontractors participated. The meeting included a tour of the facilities. Six fixed-price quotes were obtained on September 11. Clarifications were required on most of the bids.

Chapman Corp. was selected to perform the main body of the pilot plant construction job, and Allegheny Energy let the contract to Chapman Corp. on October 4, under subcontract to CONSOL. A pre-mobilization meeting was held with personnel from Chapman, CONSOL and Allegheny on October 4. Chapman started construction on October 21. Excavation was started on October 23. Formwork and rebar for the main tower were completed on October 31. Concrete work was completed on November 4. The pilot air heater was set on November 12. The Pilot electrostatic precipitator (ESP) and one induced draft (ID) Fan were set on November 13. Structural steel erection was competed and all remaining fans and mechanical equipment were set on November 21. All mechanical and piping work was completed on December 20. All instrumentation was mounted and all conduit runs were completed by December 27. Electrical wiring was competed on January 3. Insulation of the piping and mechanical equipment was competed on January 16.

Five tank and pump skids were designed, components were purchased, and the skids were assembled at CONSOL R&D. The skids, along with pipe supports and expansion joints were shipped to Mitchell Station on November 4 for installation by Chapman. Materials were ordered for the fabrication of the corrosion probe. The corrosion probe was fabricated, skid-mounted, and successfully tested at CONSOL R&D. The skid was delivered to Mitchell Station on November 26. Six compressed air and water valve trains were assembled at CONSOL R&D and delivered to Mitchell Station for installation by Chapman.

All modifications were completed to the trailer to serve as the gas sampling laboratory and control room, and the trailer was transported and setup at Mitchell Station.

Orbital Engineering completed the PLC programming in September. Another purchase order was issued to Orbital to install programming and test the PLC both at the vendor's (Applied Control Systems') shop and at Mitchell Station. Orbital completed the PLC shop testing on November 1 and updated the electrical drawings per minor wiring changes.

Unexpected field conditions required various changes to the original design of the pilot plant, as described in the following list:
The 20" knife gate valve was unobstructed when it was installed during the plant outage. However, when the plant began operating, thermal expansion of the plant ductwork caused there to be an obstruction preventing movement of the valve stem, and thus preventing the valve from being opened. Chapman was directed to remove the valve, rotate it 90^{o}, and reinstall it so that it could be operated. CONSOL R&D redesigned the 8" hot air pipe run in order to relocate the line due to the relocation of the

tie-in.

Allegheny, CONSOL, and Chapman identified tie-ins for water and compressed air on November 14. It was determined that plant water pressure was insufficient for the humidification spray nozzle; therefore, a water pump and valving to boost the pressure were specified and purchased. The water pressure boosting equipment was assembled at CONSOL R&D and installed at the plant by Chapman on January 2. It was determined that plant "instrument" compressed air is much too wet to operate the pilot plant instruments. Therefore, compressed air drying equipment was specified, purchased, and delivered to Mitchell on November 22.
Unexpected piping congestion around sample ports 'E' and 'F' limited sufficient access to the sampling ports. CONSOL R&D designed two platforms to provide sufficient access to these ports. Chapman Corp. completed the installation the two sampling platforms on January 31.

Unexpected field conditions required the redesign, purchase, and installation of five pipe supports, and additional heat tracing.

Commissioning and start up of the electrical and mechanical equipment, instruments and PLC was originally planned for the first three weeks of January. However, commissioning activities could not proceed until the main power was connected, and the main power could not be connected until there was a boiler outage. Mitchell Station Unit 3 continued to break records for uninterrupted operation until the beginning of February. Mitchell Station Unit 3 was taken off line over the weekend of February 1 and 2, and Chapman was able to connect the main power cable of the pilot plant to the power station electrical panel on February 2. Allegheny Energy installed the main breaker in the electrical panel on February 14. Chapman completed the electrical work by powering up all equipment on February 18, 2003. This completed the Chapman construction contract and Task 1. Task 1, including the entire construction activity, was completed with zero reportable accidents.

Startup and Maintenance (Task 2)

Major milestones completed during Task 2 are shown in Table B-4. A description of the activities completed during Task 2 is as follows.

Task 2 Activities - February 24, 2003 thru August 22, 2003

Commissioning and start up of the electrical and mechanical equipment, instruments and PLC by CONSOL, QSA (instrumentation), and Orbital Engineering (PLC programming) began on February 24. The Alstom Power representative completed cold testing of the pilot air heater on February 25. QSA completed instrumentation and wiring tests on February 28. Orbital Engineering started PLC programming testing on March 3; various set-up and programming problems were encountered and corrected, but these delayed plant start up. All instruments and variable speed drives were configured and operated in the manual mode.

A log of start-up and commissioning activities during this period follows:

- Orbital Engineering started PLC programming testing on March 3; various drive set-up, instrument wiring and programming problems were encountered and corrected during the next several months.
- In March, the insulation on a vertical section of the main 20" flue gas line slipped to a position covering an expansion joint. This prevented flue gas from being circulated. Chapman Corporation corrected the problem.
- Flue gas circulation was attempted on April 2, but it was discovered that two tie-ins were plugged with flyash on the host-side of the knife-gate valves. Four clean-out ports were installed at the two tie-ins to allow them to be cleaned out. The fly ash deposits were soft and friable enough to be removed by rodding. A malfunctioning flowmeter was discovered and returned for repairs.
- Flue gas was circulated for the first time on April 24, revealing a second malfunctioning flow meter, this one on the main 20" flue gas extraction duct. The flow meter was returned for repairs.
- During the next two weeks, repairs were made to the pilot air heater drive, which had overloaded, and to another failed expansion joint. The lead CONSOL engineer was sidelined with a broken collarbone.
- Start-up was resumed on May 14, and was again terminated on May 23 when the variable-speed drives controlling all three fans failed. In all three cases, the failure resulted from corrosion of the wiring to the small fans that cool the drives. The cooling fans failed causing the variable-speed drive controllers to overheat.
- A station outage began June 3. During the outage, repairs were completed on the variable frequency drives, expansion joints, flow meters, and motorized control valves.
- Flue gas again became available on June 11. A test run was completed that day to tune control loops at the heater. Adjustments to the fans and pressure monitoring instruments were completed on June 12 and 13. Surge vessels were added at three locations to reduce the pressure fluctuations that were making it difficult to control pressure differentials around the air heater. Another failed expansion joint was repaired.
- In mid-June, the air heater and slurry preparation areas of the pilot plant were operated to tune controllers, test flow meters, identify PLC logic problems, and perform ESP start-up.
- Environmental Elements Corp. attempted to start up the ESP on June 26, but the rapper control failed.
- In July, a remotely controlled operator for the flue extraction valve was installed to address safety and emergency shutdown concerns. A new temperature transmitter with a faster response time was installed on the flue gas outlet. A defective brake on the air pressure control valve was replaced. The repaired flue gas flow meter was replaced.
- On July 31, an air heater area test run was successfully completed.
- Environmental Elements Corp. replaced the rapper control circuit boards in July, and completed the start-up of the pilot ESP on August 15.
- In August, assembly, installation and testing of the ESP flyash sampling

equipment were completed and the operating/safety manual was completed and issued on September 5.

- Local emergency shutdown procedures were formulated by CONSOL and approved by Mitchell Station operating personnel.
- Pilot plant automatic control and shutdown logic testing were completed on August 22 readying the plant for continuous operation and completing start-up and commissioning.

Task 2 maintenance activities continued throughout Tasks 3-7 and a description of each activity is included under the task.

Baseline Testing (Task 3)

Pilot plant operation during Task 3 is listed in Table B-5. A description of the activities completed during Task 3 follows.

Task 3 Activities - August 28, 2003 thru January 30, 2004

Continuous unattended pilot operation started on August 28. The pilot plant operated August 28 and 29 until Mitchell Station was taken off-line for maintenance. A baseline series of air heater flow and temperature measurements were completed on August 29.

Baseline testing was started on August 28, 2003. The following tests and maintenance operations were performed:

- On August 29, a baseline series of air heater flow and temperature measurements was completed at locations A, B, C and D (Figure B-1). The presence of a substantial air leak at the air heater became apparent. It was discovered that the contractor had left two jacking ports on the air heater open. The ports were sealed to close the leaks. Near-daily sampling of coal and pilot-plant ESP flyash was started.

- In September 2003, Mitchell Station was offline for approximately two weeks. Flow meter problems prevented continuous operation until September 17. Flue gas flow measurements were conducted at three locations to check the operation of the flow meters. The measurements revealed a number of problems with the flowmeters that must be resolved prior to injection of magnesium hydroxide ($Mg(OH)_2$) slurry in Task 4, but would not prevent baseline testing from being completed. A flowmeter was returned to the manufacturer for repairs.

- From September 23 to October 8, the pilot plant was operated continuously at the baseline conditions (300 °F outlet flue gas) until Mitchell Station was shutdown.

- Ten samples of pulverizer feed coal and pilot ESP fly ash taken between 9/17/03 and 10/07/03 were analyzed. These samples were taken in the early operating period of the pilot plant, and thus they may not reflect lined-out operation.

- On October 7, a baseline series of air heater flow and temperature measurements was completed at locations A, B, C and D. The presence of a substantial air leak at the air heater was still apparent. Since the leakage in the air heater is forced to be from the gas side to the air side, it was concluded that the air leak would not interfere with the baseline measurements of the flue gas.

- On October 9, baseline mercury, SO_3 and particulate sampling was postponed due to failure of the pilot ESP rappers.

- From October 9 to 24, the pilot air heater area was operated continuously, while troubleshooting and repairs were done to the pilot ESP rapper controller.

- From October 24 to November 7, further repairs to the pilot ESP mandated a stop to all pilot-plant operations. An internal inspection revealed that a Teflon barrier separating the high-voltage compartment from the main chamber had slipped, allowing large amounts of flyash to enter the high-voltage compartment. The flyash deposit lead to arcing, which scorched the surface of the high-voltage rapper insulator and destroyed it. A replacement insulator, and parts needed to improve the support of the Teflon barrier were installed. Another defective main flue-gas flowmeter was returned to the manufacturer for repairs.

- From November 10 to 14, the pilot plant was operated until a rapper insulator failure occurred in the pilot ESP.

- From November 17 to December 10, removal of the access doors to all three high-voltage compartments of the ESP revealed that the high-voltage rapper insulator rods on Fields #1 and #2 had failed due to arcing, apparently initiated by moisture condensation. Environmental Elements Corporation (EEC) shipped replacement insulators and recommended the installation of a hot-air purge for the high-voltage compartments. CONSOL specified and ordered the hot-air purge equipment. On November 25, EEC sent a technician from REDKOH Industries to adjust the poorly functioning ESP high-voltage controls. As soon as the controls were properly adjusted, it became apparent that the high-voltage wall bushings on all three fields had failed, limiting the voltage that could be applied. The failed high-voltage ceramic wall bushings on all three fields were replaced and a hot-air-purge system was installed on the high-voltage compartments. The refurbished main flue gas flowmeter and new air-inlet temperature sensor were installed the week of December 1. When high-voltage was applied to each of the fields, it was revealed that a stand-off insulator on Field #2 had failed. The pilot plant was restarted on December 11.

- From December 11 to 19, the pilot ESP was operated at a reduced flow rate due to insulator problems in Field #2, but this did not prevent the sampling program from proceeding.

- On December 17, mercury sampling was conducted at locations A, F and G (Figure B-1). Location A is upstream of the pilot air heater. Location F is immediately upstream of the pilot electrostatic precipitator (ESP). Location G is downstream of the ESP.

- On December 19, baseline SO_3 sampling was done at locations A, F and G.

- From December 22, 2003, to January 29, 2004, the pilot ESP was opened for inspection revealing that the porcelain wall bushings in Fields #1 and 3 had cracked at the base. This failure is similar to the previous failures. After some discussion with Environmental Elements Corp. (EEC) and Lapp Insulator Company (a bushing manufacturer), it was agreed that the cracking was most likely due to shock loads being transmitted through the connection to the high-voltage electrode during the electrode rapping sequence. A flexible connector was installed to prevent future occurrences of this problem. New wall bushings were supplied from old CONSOL R&D stock. The insulator for Field #2 did not arrive in time to be replaced. The pilot plant was restarted on January 19. Since the ESP Field #2 was operating at less than optimum, the flow rate of gas to the ESP was reduced by one-third of maximum flow. By January 20 the performance of ESP Field #3 had declined, but Field #1 continued to operate well. The high-voltage rapper insulator rod heaters and a hot air purges installed on each of the three ESP fields in December to address failures due to condensation of water and flyash contamination worked well.

- On January 20 and 21, SO_3 sampling was completed at the air heater sample port locations A (flue gas inlet), B (flue gas outlet), and D (air outlet).

- On January 28, particulate sampling was completed at locations F and G (inlet and outlet, respectively, of the pilot electrostatic precipitator (ESP).

- On January 29, mercury sampling was completed at the inlet and outlet of the pilot air heater (locations A and B) and ESP (locations F and G). This completed Task 3, Baseline Testing.

Sorbent Evaluation (Task 4)

Pilot plant operation during Task 4 is listed in Table B-6. A description of the activities completed during Task 4 follows.

Task 4 Activities - February 1, 2004 thru March 3, 2004

Alstom representatives visited the pilot plant on February 10 to examine the condition of the pilot air heater. This examination was timed to follow completion of the Baseline Testing and precede the start of $Mg(OH)_2$ injection. One cold-end basket and one hot-end basket were removed for inspection and replaced with two new baskets. Alstom's initial examination of the baskets to assess the condition of the metal surfaces revealed no sign of corrosion, or ash buildup or any other deposits on the metal surfaces. As the air heater access door was unbolted in preparation for the removal of the baskets, it

was noted that the door gasket had failed. This was the major source of the air leak that was noticed.

The broken wall bushing in Field #3 of the pilot electrostatic precipitator (ESP) was replaced after the connections to the bushing were further modified. In addition, the rapping force on the electrode and collector plate was reduced. Both stand-off insulators in Field #2 were replaced, but there was no improvement in the operating voltage. The operation of the $Mg(OH)_2$ slurry preparation equipment was retested on water. The first tank of concentrated slurry was set in place on February 20.

On February 24 and 27 and March 1 with low temperature (240-250 °F) operation of the pilot air heater, mercury and particulate sampling was conducted at the pilot electrostatic precipitator (ESP) inlet (locatio F) and outlet (location G) at a reagent injection rate of approximately 2.5:1 molar $Mg(OH)_2$:SO_3.

On March 2 and 3, during low temperature (240-250 °F) operation of the pilot air heater, SO_3 sampling was conducted at the air heater flue gas inlet (location H) and outlet (location B), air heater air outlet (location D), and upstream of the slurry injection location (location A) at an injection rate of approximately 2.5:1 $Mg(OH)_2$:SO_3 on March 2 and at an injection rate of approximately 5:1 $Mg(OH)_2$:SO_3 on March 3. Operations were conducted at these conditions for 6 to 7 hours per operating day.

During the first day of reagent injection, February 24, there was a considerable drop in current from 3 to 0.2 mA in the first field of the ESP after six hours. After another six hours of operation on the second day of reagent injection, February 27, all three fields were operating at lower current and voltage. On March 2, the first field of the ESP automatically shut down due to undervoltage. The ESP was taken offline to prevent damage. All of these ESP problems proved to be unrelated to $Mg(OH)_2$ injection and low temperature operation. The SO_3 sampling at the air heater was completed on March 3 without regard for the pilot ESP. The air heater showed no signs of fouling during the four operating periods of 6 to 7 hours per day of reagent injection and low temperature operation.

On March 3, a series of air heater flow and temperature measurements was completed at locations A, B, C and D. Air leakage into the air heater has been reduced. This completed Task 4, Sorbent Evaluation.

Parametric Testing (Task 5)

Pilot plant operation during Task 5 is listed in Table B-6. A description of the activities completed during Task 5 follows.

Task 5 Activities - March 4, 2004 thru March 26, 2004

Parametric testing was started on March 24 and completed on March 25, 2004. The following tests and maintenance operations were performed:

On March 24 and 25, the flue gas operating temperature at the air heater outlet was

reduced to 225 °F while $Mg(OH)_2$ reagent was injected at a rate of approximately 4:1 molar $Mg:SO_3$ to determine the impact on mercury capture. Mercury and flyash sampling were conducted at the pilot electrostatic precipitator (ESP) gas inlet (location F), gas outlet (location G) and flyash discharge on March 24 and 25. In spite of the fact that the second field of the pilot ESP was shutdown due to failure of the controller and the first field failed due to a high voltage insulator failure on March 25, the flyash removal remained at 99 and 90 percent during the testing. The pilot air heater showed no signs of increased pressure drop due to fouling during the two days (6-7 hours each) of operation at these conditions. This completed the testing aspect of Task 5.

On March 26, a representative from Environmental Elements Corp. (EEC) inspected the controller and other problems at the pilot ESP. Several components in the high-voltage and current-control systems were replaced. The high-voltage cable termination at the transformer was repaired and a failed insulator rod was replaced on the first field. The insulator rod failure was due to acid condensation which occurred during a brief period when the pilot plant operated without $Mg(OH)_2$ injection. After these repairs were made, it became apparent that the wall bushing on Field #2 had failed. The controller parameters were adjusted to improve the ESP operation.

HUMIDIFICATION TESTS (TASK 6)

Pilot plant operation during Task 6 is listed in Table B-6. A description of the activities completed during Task 6 follows.

Task 6 Activities - March 27, 2004 thru April 15, 2004

Humidification tests to determine the impact of water-spray cooling on mercury capture were started on April 1 and completed on April 13, 2004. The following tests and maintenance operations were performed:

On April 1, $Mg(OH)_2$ reagent was injected at a rate of approximately 4:1 molar $Mg:SO_3$ and the pilot air heater was operated to control its flue gas exit temperature at 312 °F. The water spray system was operated to reduce the flue gas temperature at the ESP inlet to 240 °F. Mercury and flyash sampling were conducted at the pilot ESP gas inlet (location F), gas outlet (location G) and flyash discharge on April 1. The first and third fields (but not the second field) of the pilot ESP were operating during this test. Further testing was delayed due to water condensation in the flyash sampling equipment at the pilot ESP.

On April 13, Humidification testing was completed at essentially the same conditions as used on April 1. Two sets of mercury and flyash samples were taken at the pilot electrostatic precipitator (ESP) gas inlet (location F), gas outlet (location G) and flyash discharge on April 13 to determine the impact of water-spray cooling on mercury capture. Task 6 Ontario Hydro sampling train data are shown in Table B-4.

Long Term Testing (TASK 7)

Pilot plant operation during Task 7 is listed in Table B-7. A description of the activities completed during Task 7 follows.

Task 7 Activities - April 16, 2004 thru September 3, 2004

Preparations for long-term testing were started on April 16 and actual long-term testing began on August 21, 2004. The following maintenance operations were performed:

In July, The replacement high-voltage cable for Field #2 of the pilot ESP and the air-barrier nozzles for the $Mg(OH)_2$ reagent injection and water spray lances were delivered and installed.

From July 23 to 29, Environmental Elements sent a technician to address high-voltage breakdown at the transformer bushing on pilot ESP Field #1, and low voltage and current conditions on Field #2 of the pilot ESP. The high-voltage breakdown at the transformer bushing on Field #1 was resolved, but the low voltage and current conditions on Field #2 were due to a transformer failure that could not be repaired readily. Thus, moving forward, the ESP is operated with Field #2 turned off or at 27 kV (instead of at the 45-55 kV expected for a well-operating field). This is satisfactory because most of the short-term testing was completed with Field #2 turned off (Tasks 5 and 6), or at low voltage (Tasks 3 and 4) and yet the pilot ESP collected virtually all of the particulate mercury from the gas, as indicated by Ontario Hydro speciation results.

During the week of August 9, one each of a cold-end and a hot-end basket from the pilot air heater were removed for inspection by Alstom. Replacement baskets were installed.

During the week of August 16, the PLC programming modifications to improve pilot plant operability were completed and tested. The calibrations of the temperature and pressure transmitters were checked to verify proper operation.

On August 21, long-term testing began. The gas was cooled via the pilot air heater to 220 °F at the pilot ESP inlet. Magnesium hydroxide was injected at a molar ratio of approximately 4:1 with the anticipated sulfur trioxide. The magnesium hydroxide injection slurry nozzles plugged after only eight hours of operation. Lechler, the nozzle supplier, indicated that similar problems have occurred in another application, and they agreed to send us a redesigned nozzle. So that testing could continue to operate the pilot plant until the new nozzle arrives, we chamfered the holes in the existing nozzle, per Lechler's recommendations. This modification allowed up to 30 hours of operation before cleaning was required. Long-term testing was re-started on August 27. From August 27, 2004, through September 3, 2004, two 30-hour runs were completed.

Task 7 Activities - September 4, 2004 thru January 5, 2005

From September 7 through 9 (for a total of 55 hours, with a one-hour interruption after 24 hours to clean the slurry nozzle), the flue gas was cooled via the pilot air heater to

220 °F at the pilot ESP inlet. Mercury sampling was conducted in triplicate via the Ontario Hydro method on September 8 and 9 at the pilot ESP inlet and outlet (locations F and G). Sulfur trioxide sampling was conducted via the controlled condensation method on September 8 and 9 upstream and downstream of the slurry injection location prior to the pilot air heater flue gas inlet (locations A and H). There was no apparent loss in performance of the pilot air heater and, thus, no sign of fouling during this period. The operation and performance of the ESP were stable during this period (only two of three fields were operating, Field #2 failed on September 8); flyash removal remained fairly constant at about 99.5%.

An outage for maintenance at Mitchell Station Unit #3 started on September 10 and continued through mid-November.

On November 12 the pilot ESP Fields #1 and #2 were opened for inspection because Field #1 was experiencing some sparking under no-flow conditions and Field #2 had failed on September 8. There was a build up of what appeared to be high-carbon fly ash on the Teflon barrier in Field #1; this deposit was removed in order to restore full operation of the field. The build up of high-carbon ash most likely occurred on September 8 during the tests at maximum boiler load. An examination of Field #2 confirmed that the high voltage transformer had failed. The pilot ESP was operated without Field #2 for the remainder of the long-term tests. This inspection generally indicated that there was no detrimental effect of the low-temperature operation on the pilot ESP. The Teflon barrier is unique to the pilot ESP, and so the ash build up on that barrier is peculiar to the pilot ESP. EEC reviewed the long-term operating test data from the pilot ESP and concluded that there was no detrimental effect of the low-temperature operation on the pilot ESP. However, they cautioned that their conclusions could not yet address the potential for long-term corrosion.

After numerous maintenance problems were resolved during the week of November 29, startup of the pilot plant was attempted on December 3 until the variable speed drive on the Air ID Fan failed due to water accumulation inside the enclosure. The drive was replaced on December 6 and the pilot plant was restarted on December 7. The plant was operated with flue temperatures at the ESP inlet of 215 °F for 64 hours and 200 °F for 8 hours. The air heater was operated the entire time from December 7 through December 11 (approx. 72 hours) without sootblowing without any noticeable change in pressure drop. Photographs of the cold end were taken to check for deposits before restarting. The ESP continued to operate normally. Coal samples and flyash samples were collected.

During December 14, 15 and 16 the pilot plant was operated with deep cooling via the air heater such that flue gas temperatures at the pilot ESP inlet were 215 to 205 °F. Three mercury sampling runs were completed at the pilot ESP and four SO_3 sampling runs were completed at the inlet of the air heater at these conditions. All pilot plant components worked well.

During December 16 and 17, the pilot plant was operated such that the flue gas was

cooled with the air-heater to 270 °F, and then with water spray cooling to about 215 °F at the pilot ESP inlet. Two mercury sampling runs were completed at the pilot ESP at these conditions. A planned third mercury sampling run could not be completed due to failure of the pilot ESP during the second sampling run.

From December 14 through 17 the air heater was operated (approx. 72 hours) without sootblowing without any noticeable change in pressure drop. Visual inspection and photographs of the cold end did not reveal any accumulation of deposits.

The pilot ESP was opened for inspection on December 20 to find that a 1/8" layer of flyash had accumulated on the flue gas side of a Teflon barrier, and that this had shorted out the power supply. The fly ash deposits were removed easily; however, it was noticed that the Teflon surface developed a strong static charge as the flyash was bushed off. The cleaning restored the performance of the pilot ESP.

The plant was restarted on December 22 with air heater cooling of the flue gas to 270 °F and with water spray cooling to about 215 °F at the pilot ESP inlet. Within an hour after the water spray was started, the ESP failed. To the operators, it appeared that the addition of water changed the characteristics of the flyash such that the flyash would quickly accumulate on the surface of the Teflon barrier in the pilot ESP.

On January 5, 2005, one each of a cold-end basket and a hot-end basket from the pilot air heater were removed for inspection by Alstom. This completed Task 7.

Corrosion Study (Task 8)

The Corrosion Study was conducted during Tasks 3 through 7 by exposing two separate temperature-controlled coupons at the pilot ESP inlet (Location F) and three in-duct coupons at the pilot ESP outlet (Location G). The exposure time and temperature at each location is shown in Table B-8. Figure B-14 shows an assembly drawing of the probe.

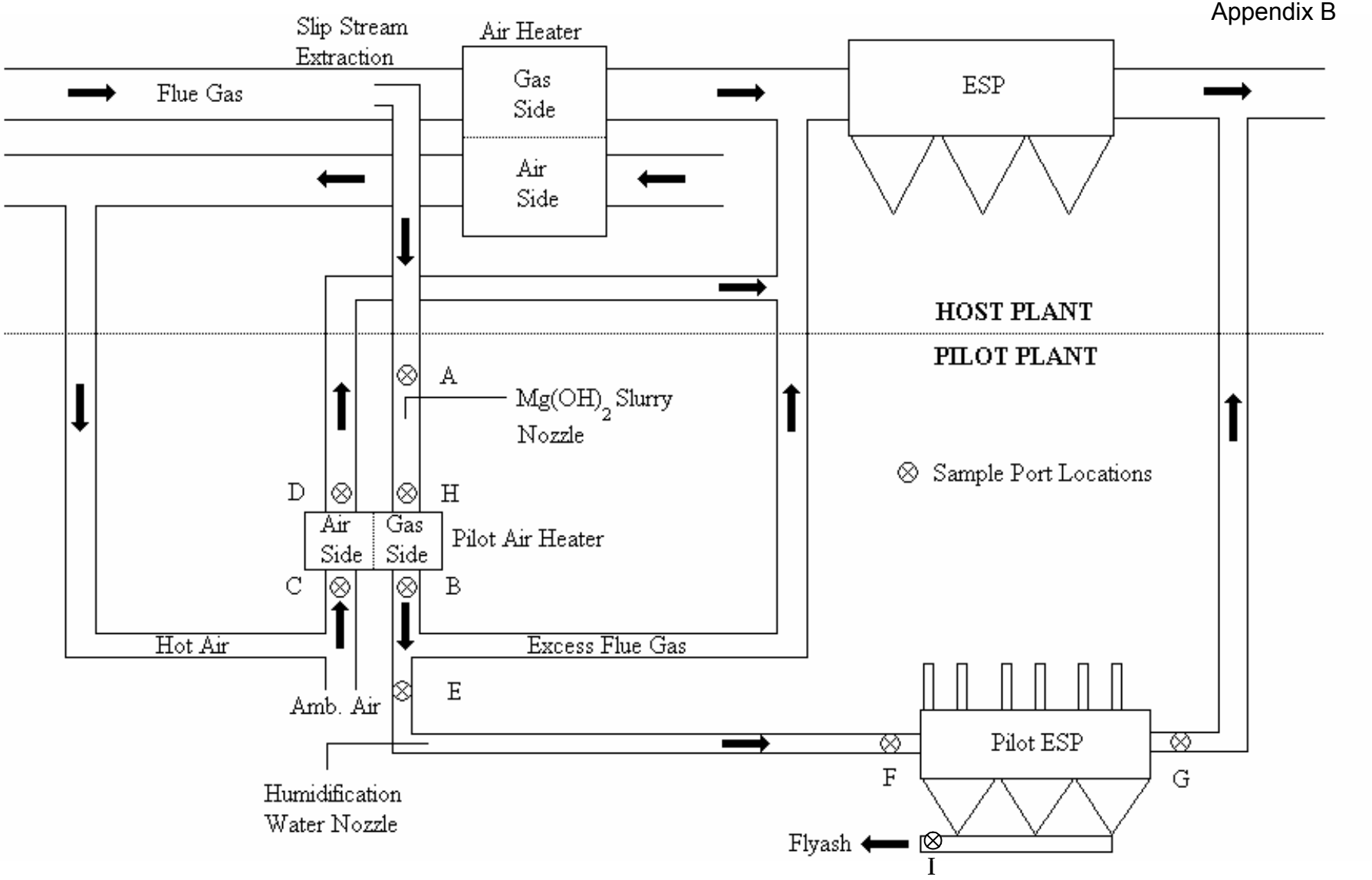
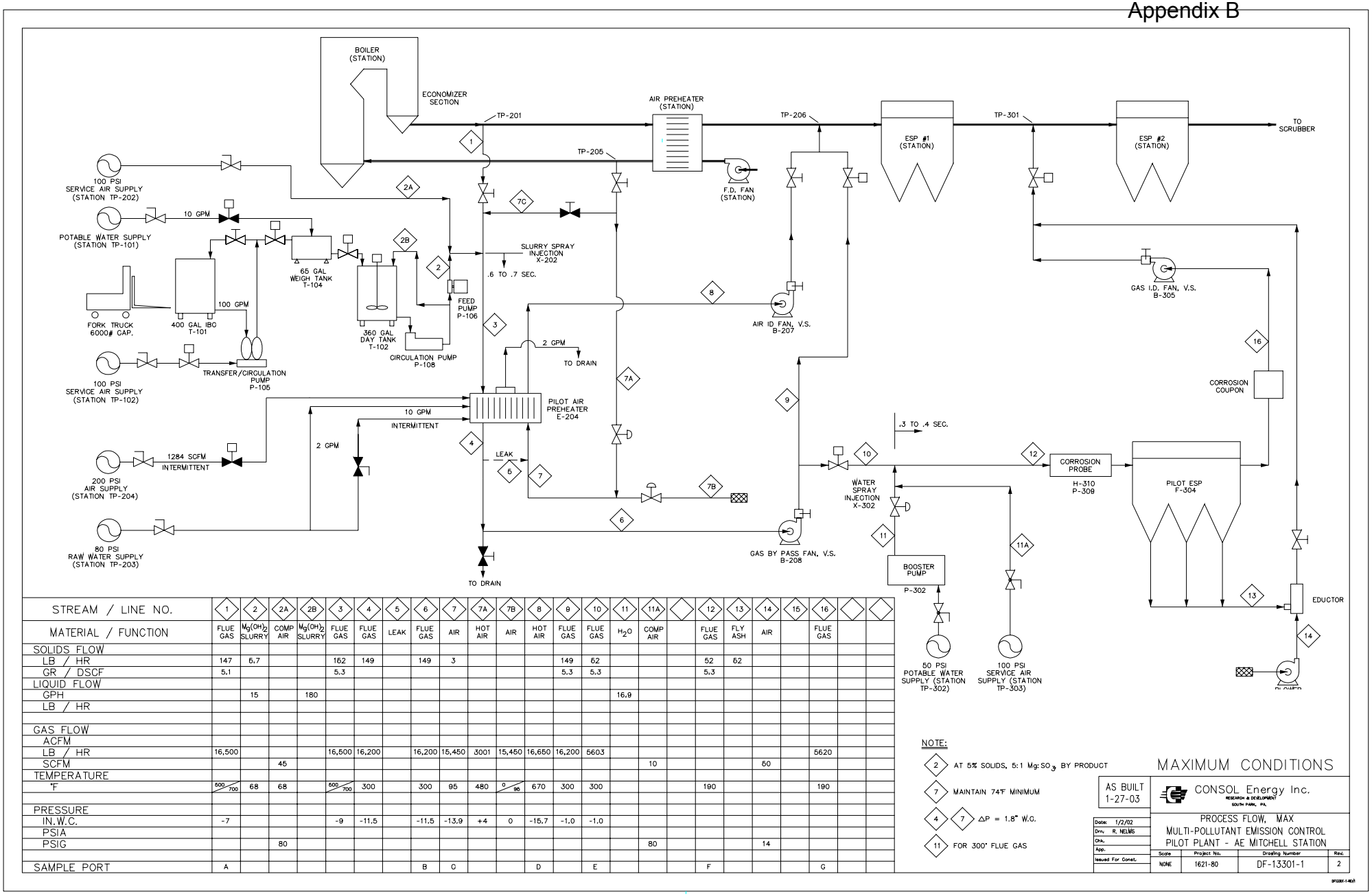


Figure B-1. Diagram of Pilot Plant Showing Sampling Locations "A" through "I"



STREAM / LINE NO.	1	2	2A	2B	3	4	5	6	7	7A	7B	8	9	10	11	11A		12	13	14	15	16		
MATERIAL / FUNCTION	FLUE GAS	$Mg(OH)_2$ SLURRY	COMP AIR	$Mg(OH)_2$ SLURRY	FLUE GAS	FLUE GAS	LEAK	FLUE GAS	AIR	HOT AIR	AIR	HOT AIR	FLUE GAS	FLUE GAS	H_2O	COMP AIR		FLUE GAS	FLY ASH	AIR		FLUE GAS		
SOLIDS FLOW																								
LB / HR	147	6.7			152	149		149	3				149	62				52	62					
GR / DSCF	5.1				5.3								5.3	5.3				5.3						
LIQUID FLOW																								
GPH		15		180											16.9									
LB / HR																								
GAS FLOW																								
ACFM																								
LB / HR	16,500				16,500	16,200		16,200	15,450	3001	15,450	16,650	16,200	5603								5620		
SCFM			45													10				50				
TEMPERATURE																								
°F	500/700	68	68		500/700	300		300	95	480	0/95	670	300	300				190				190		
PRESSURE																								
IN.W.C.	-7				-9	-11.5		-11.5	-13.9	+4	0	-15.7	-1.0	-1.0										
PSIA																								
PSIG			80													80				14				
SAMPLE PORT	A							B	C			D		E				F				G		

NOTE:

2 AT 5% SOLIDS, 5:1 Mg:SO_3 BY PRODUCT

7 MAINTAIN 74°F MINIMUM

4 7 ΔP = 1.8" W.C.

11 FOR 300° FLUE GAS

MAXIMUM CONDITIONS

AS BUILT 1-27-03

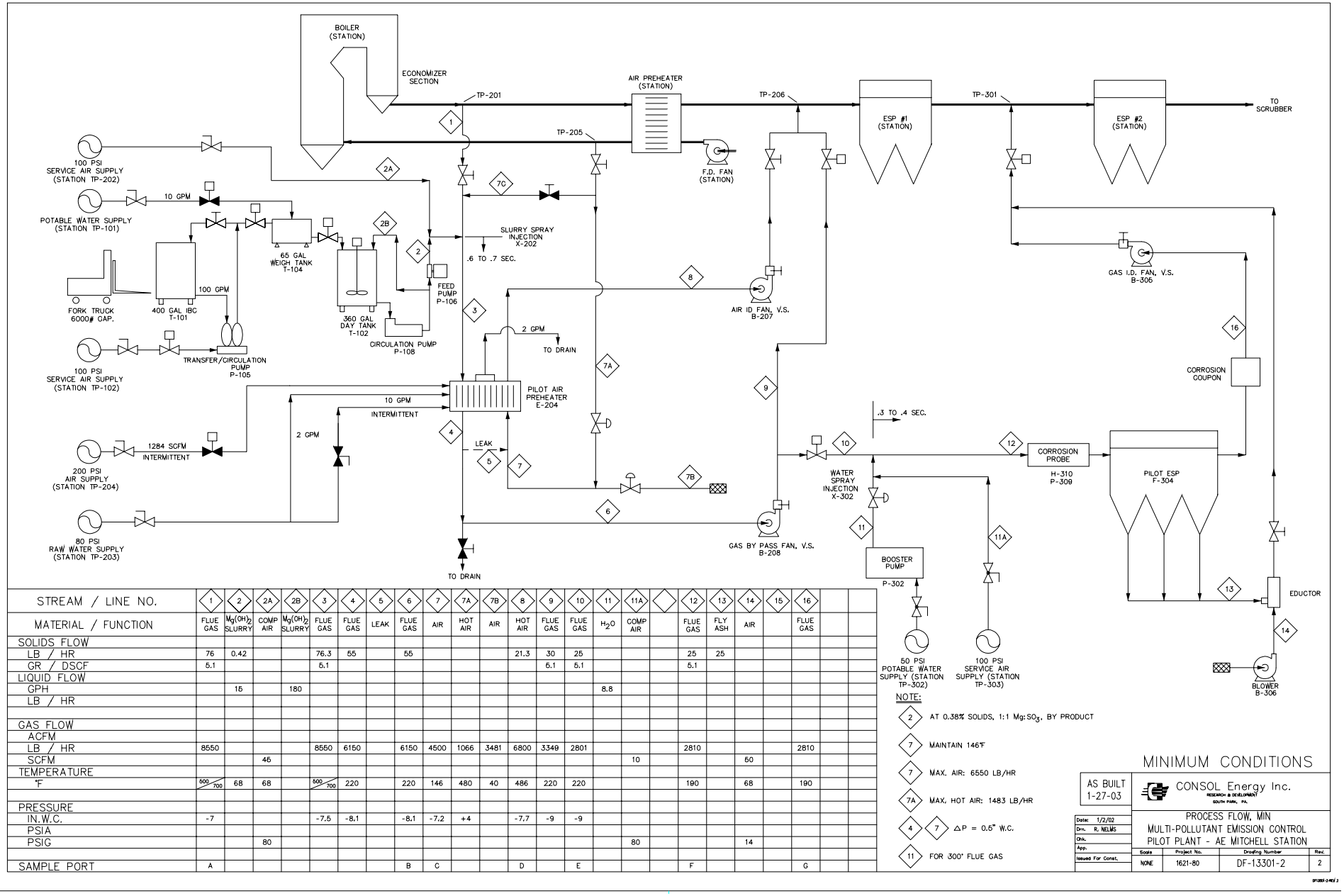
CONSOL Energy Inc. RESEARCH & DEVELOPMENT SOUTH PARK, PA.

Date: 1/2/02
Drn. R. NELMS
Chk.
App.
Issued For Const.

PROCESS FLOW, MAX
MULTI-POLLUTANT EMISSION CONTROL
PILOT PLANT - AE MITCHELL STATION

Scale	Project No.	Drawing Number	Rev.
NONE	1621-80	DF-13301-1	2

Figure B-2. Process Flowchart, Maximum Flows



STREAM / LINE NO.	1	2	2A	2B	3	4	5	6	7	7A	7B	8	9	10	11	11A		12	13	14	15	16	
MATERIAL / FUNCTION	FLUE GAS	$Mg(OH)_2$ SLURRY	COMP AIR	$Mg(OH)_2$ SLURRY	FLUE GAS	FLUE GAS	LEAK	FLUE GAS	AIR	HOT AIR	AIR	HOT AIR	FLUE GAS	FLUE GAS	H_2O	COMP AIR		FLUE GAS	FLY ASH	AIR		FLUE GAS	
SOLIDS FLOW																							
LB / HR	76	0.42			76.3	55		55				21.3	30	25				25	25				
GR / DSCF	5.1				5.1								5.1	5.1				5.1					
LIQUID FLOW																							
GPH		15		180											8.8								
LB / HR																							
GAS FLOW																							
ACFM																							
LB / HR	8550				8550	6150		6150	4500	1066	3481	6800	3349	2801				2810				2810	
SCFM			45													10				50			
TEMPERATURE																							
°F	500/700	68	68		500/700	220		220	146	480	40	486	220	220				190		68		190	
PRESSURE																							
IN.W.C.	-7				-7.5	-8.1		-8.1	-7.2	+4		-7.7	-9	-9									
PSIA																							
PSIG			80													80				14			
SAMPLE PORT	A							B	C			D		E				F				G	

NOTE:

2 AT 0.38% SOLIDS, 1:1 $Mg:SO_3$, BY PRODUCT

7 MAINTAIN 146°F

7 MAX. AIR: 6550 LB/HR

7A MAX. HOT AIR: 1483 LB/HR

4 7 ΔP = 0.6" W.C.

11 FOR 300° FLUE GAS

MINIMUM CONDITIONS

AS BUILT 1-27-03

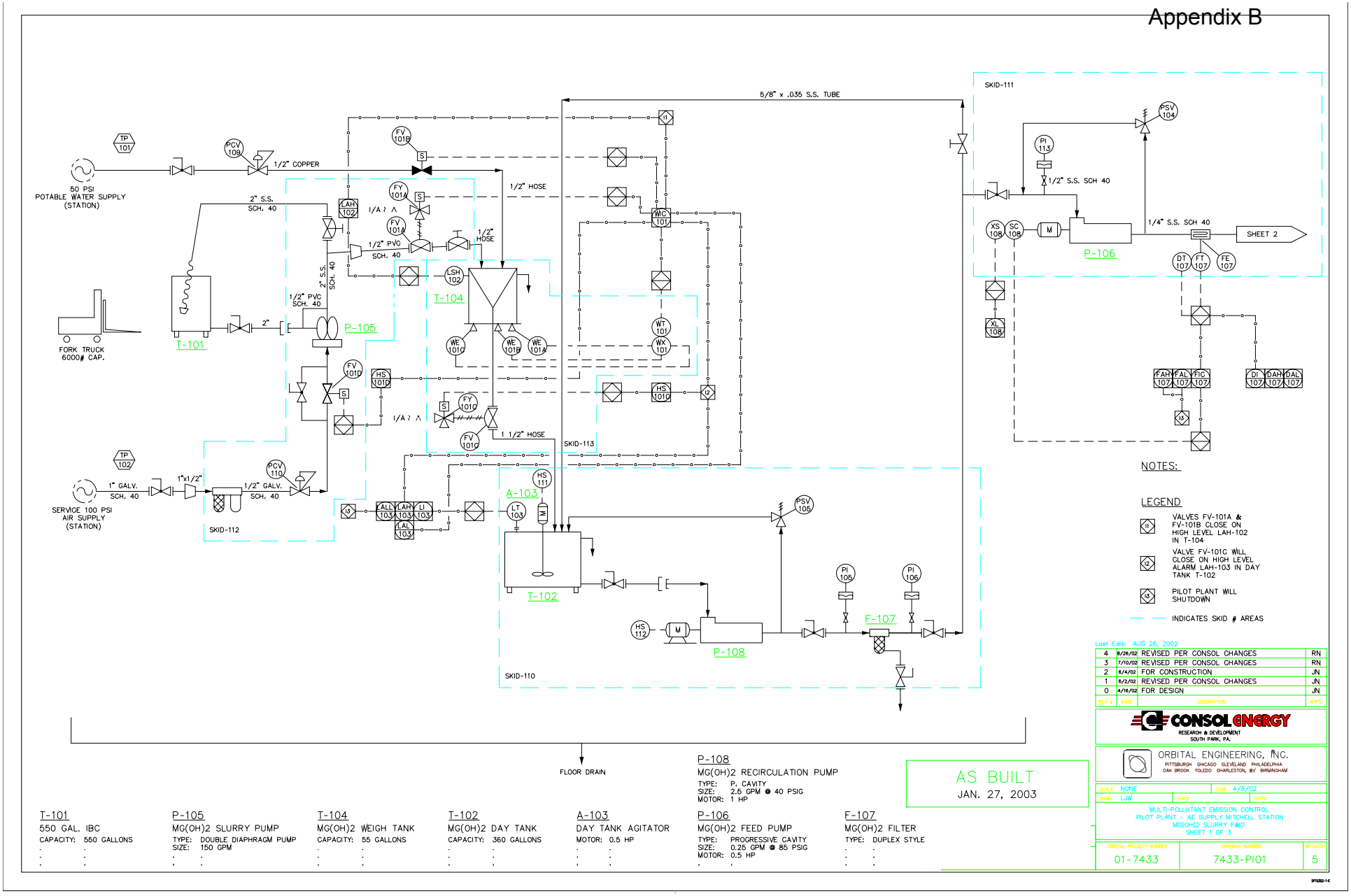
CONSOL Energy Inc. RESEARCH & DEVELOPMENT SOUTH PARK, PA.

Date: 1/2/02
Drn. R. NELMS
Chk.
App.
Issued For Const.

PROCESS FLOW, MIN
MULTI-POLLUTANT EMISSION CONTROL
PILOT PLANT - AE MITCHELL STATION

Scale	Project No.	Drawing Number	Rev.
NONE	1621-80	DF-13301-2	2

Figure B-3. Process Flow Sheet, Minimum Flows



T-101
550 GAL. IBC
CAPACITY: 550 GALLONS

P-105
MG(OH)2 SLURRY PUMP
TYPE: DOUBLE DIAPHRAGM PUMP
SIZE: 150 GPM

T-104
MG(OH)2 WEIGH TANK
CAPACITY: 55 GALLONS

T-102
MG(OH)2 DAY TANK
CAPACITY: 360 GALLONS

A-103
DAY TANK AGITATOR
MOTOR: 0.5 HP

P-106
MG(OH)2 FEED PUMP
TYPE: PROGRESSIVE CAVITY
SIZE: 0.25 GPM @ 85 PSIG
MOTOR: 0.5 HP

F-107
MG(OH)2 FILTER
TYPE: DUPLEX STYLE

P-108
MG(OH)2 RECIRCULATION PUMP
TYPE: P. CAVITY
SIZE: 2.6 GPM @ 40 PSIG
MOTOR: 1 HP

Figure B-4. Mg(OH)2 Slurry Area, P&I Diagram

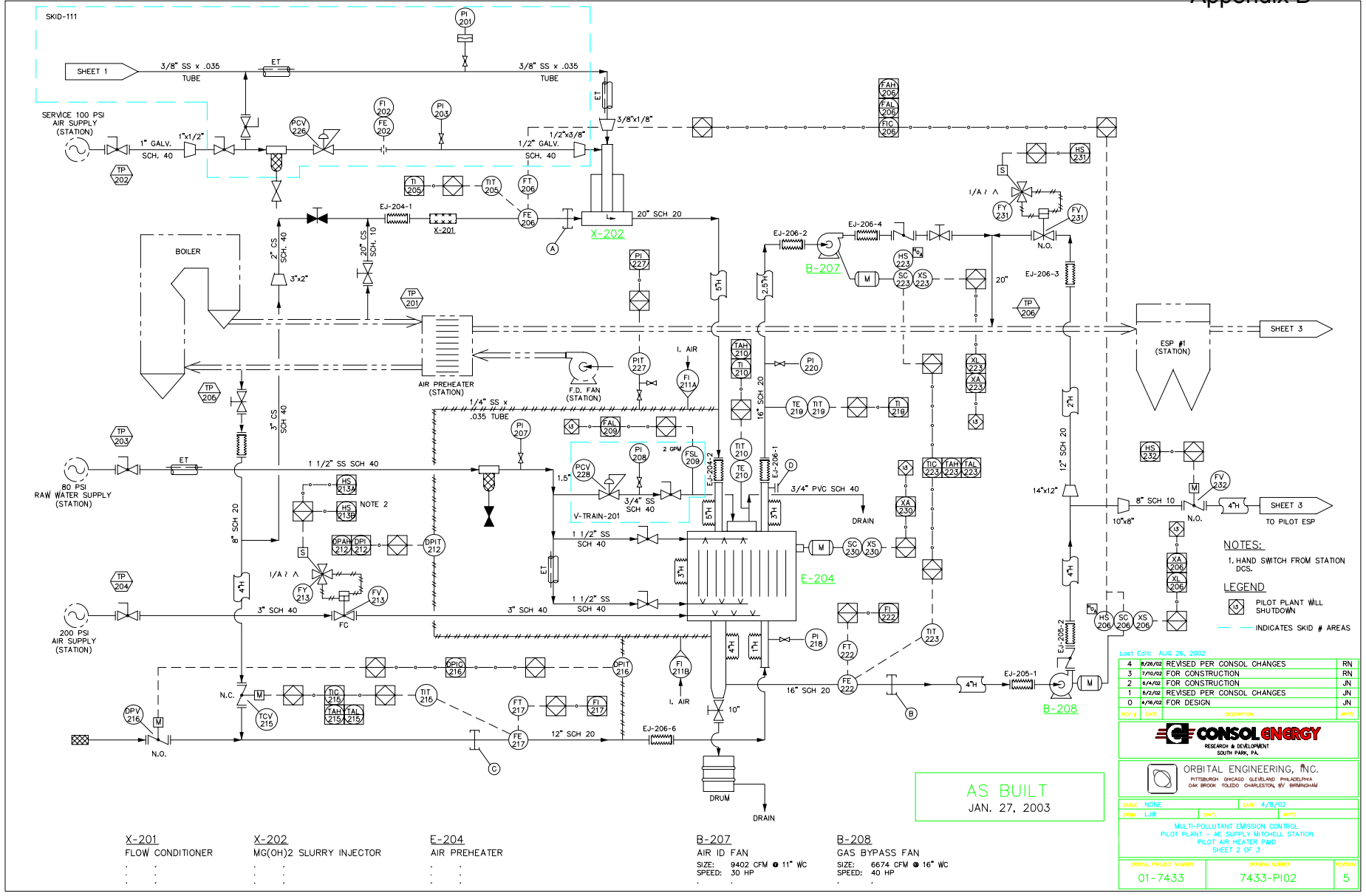


Figure B-5. Pilot Air Heater Area, P&I Diagram

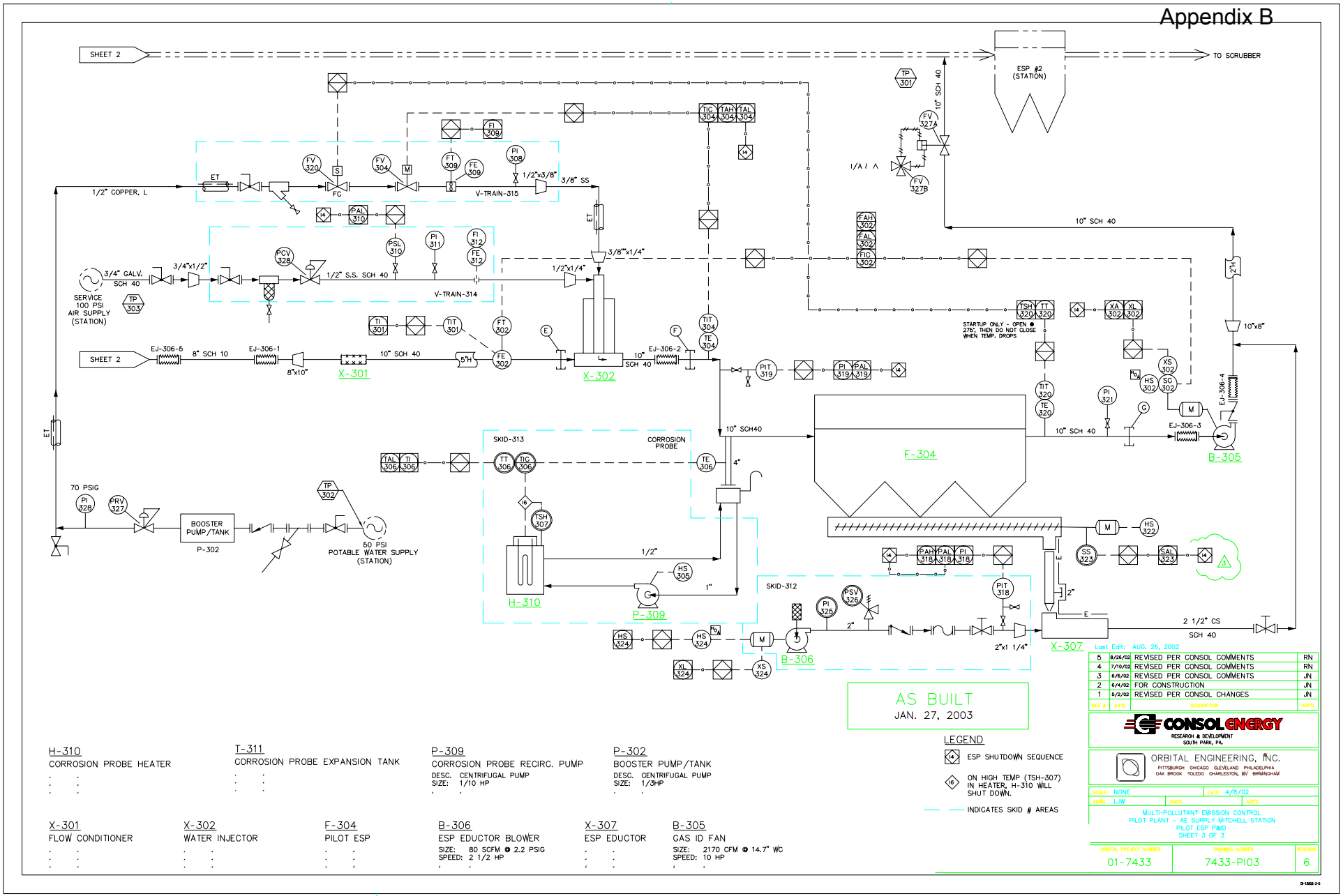


Figure B-6. Pilot ESP Area, P&I Diagram

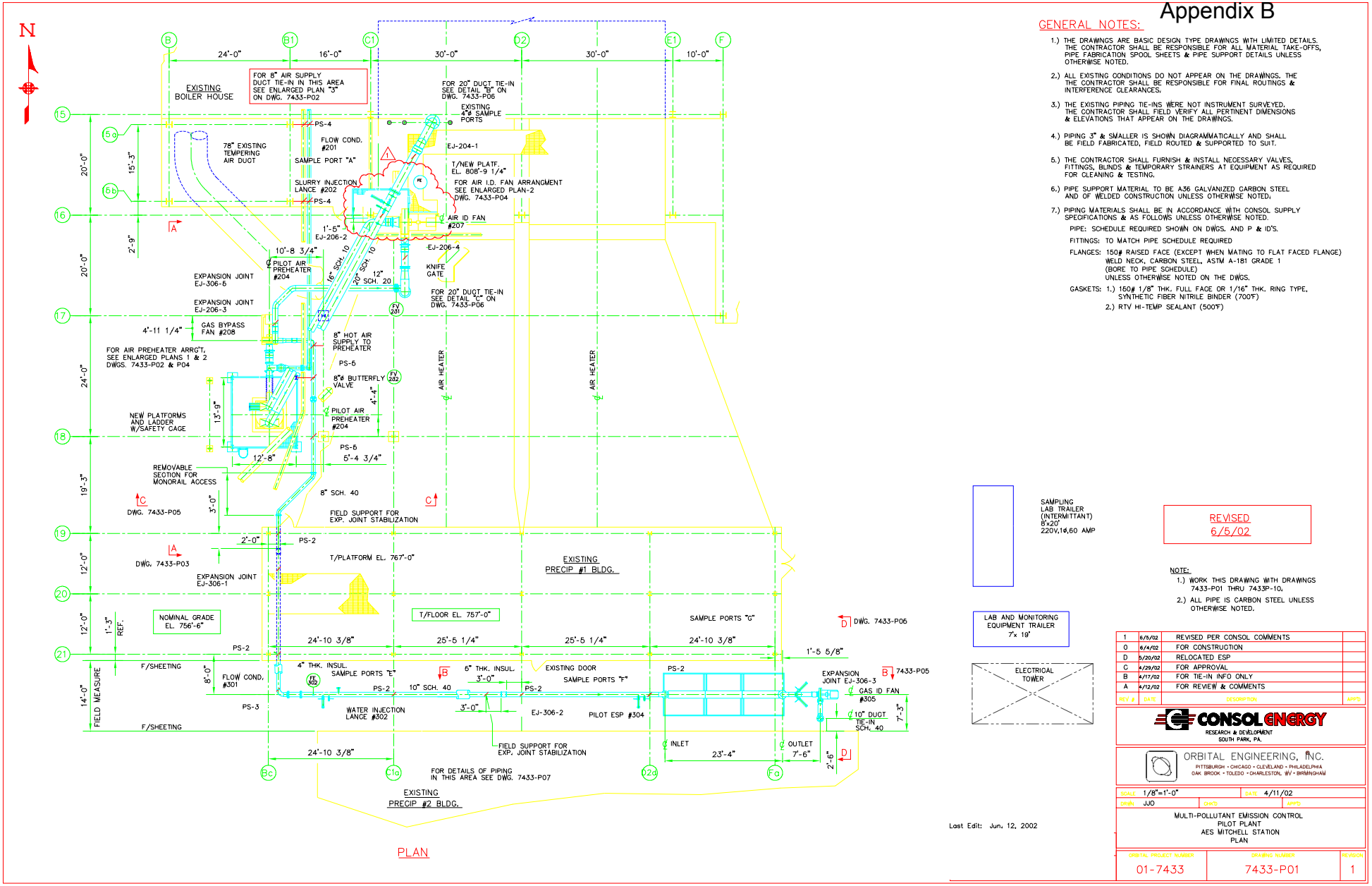


Figure B-7. General Arrangement & Piping, Plan View

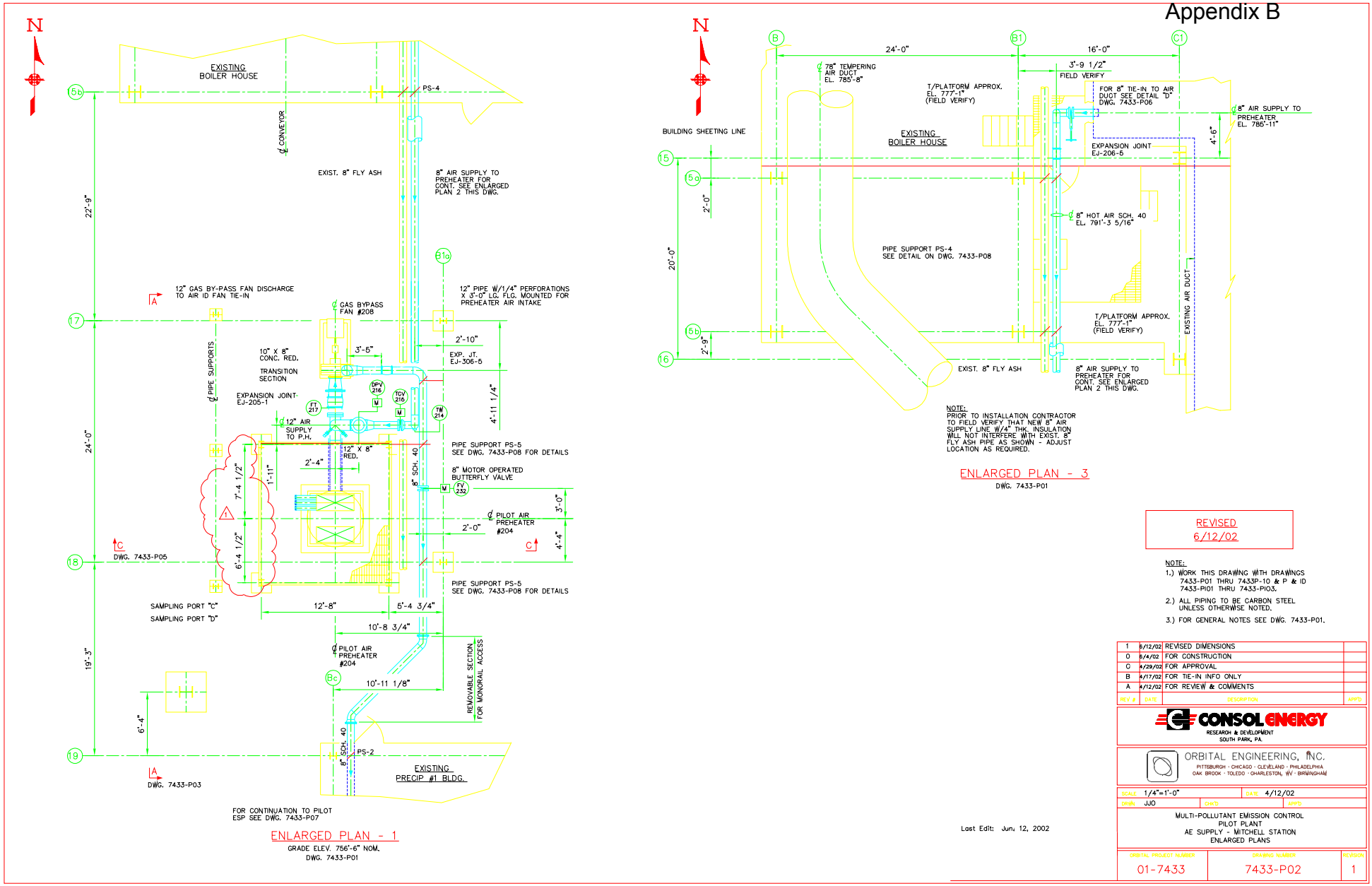


Figure B-8. General Arrangement & Piping, Enlarged Plan View

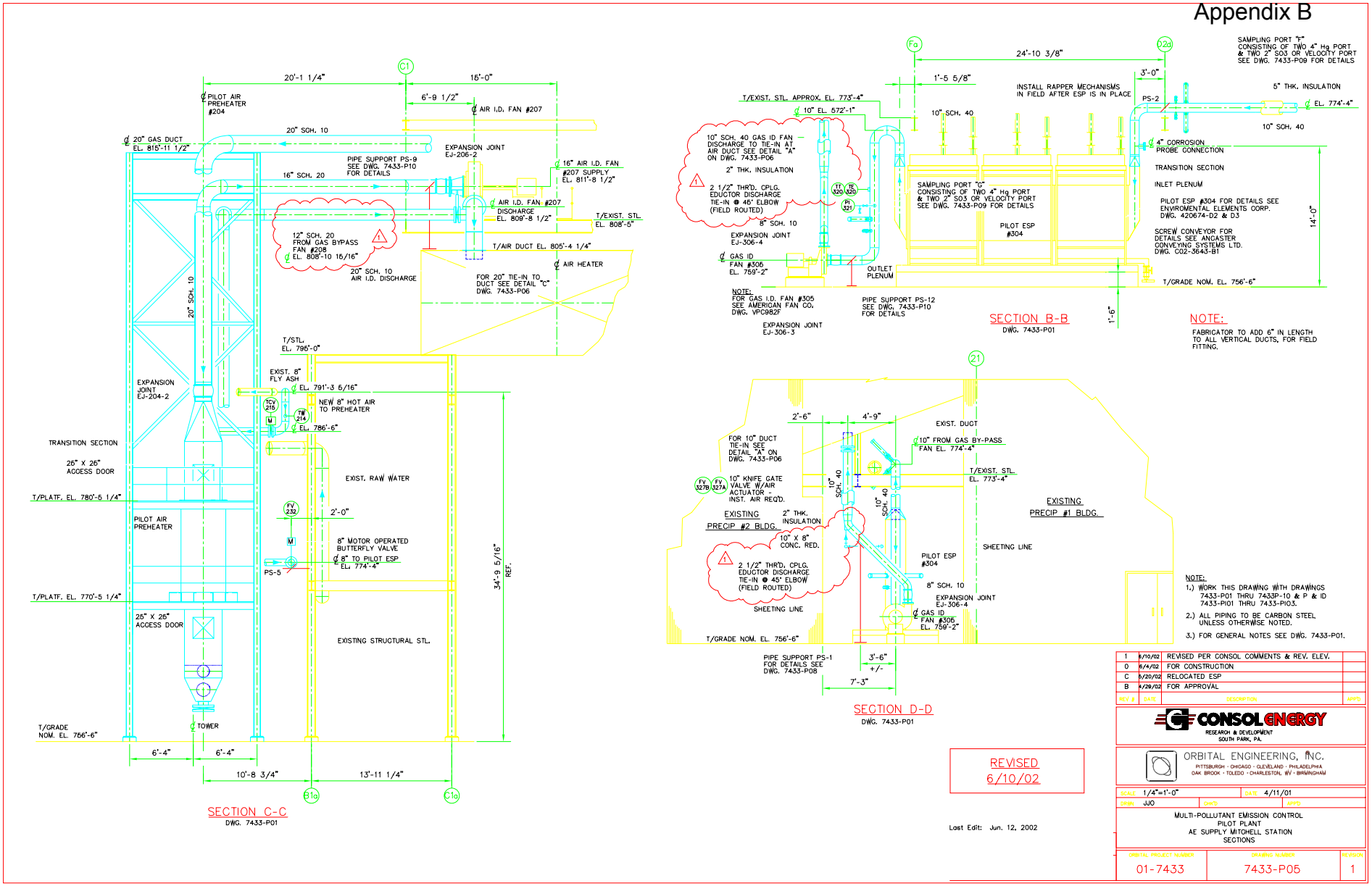


Figure B-9. General Arrangement & Piping, Section Views

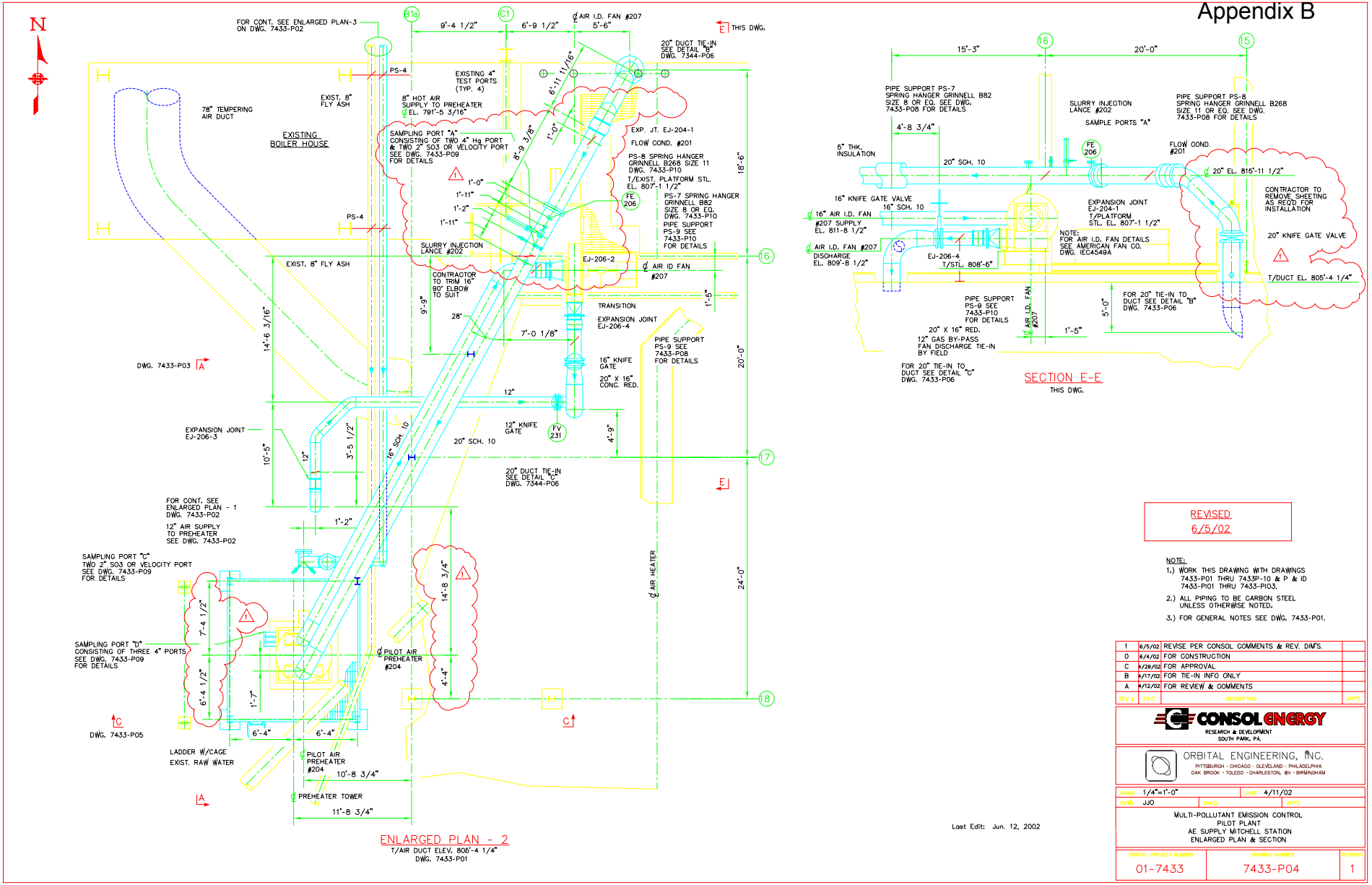


Figure B-10. General Arargement & Piping, Enlarged Plan & Section Views

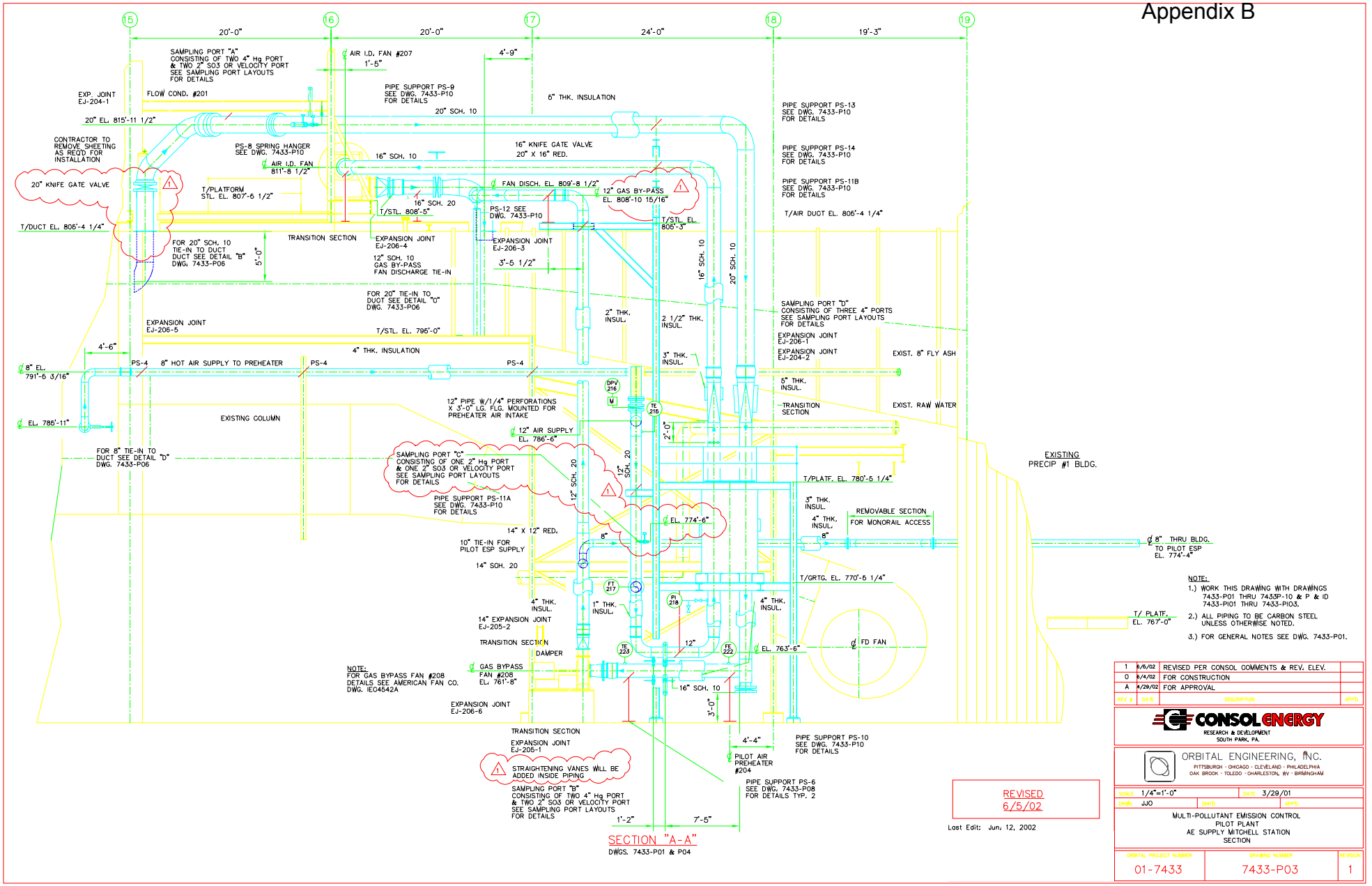
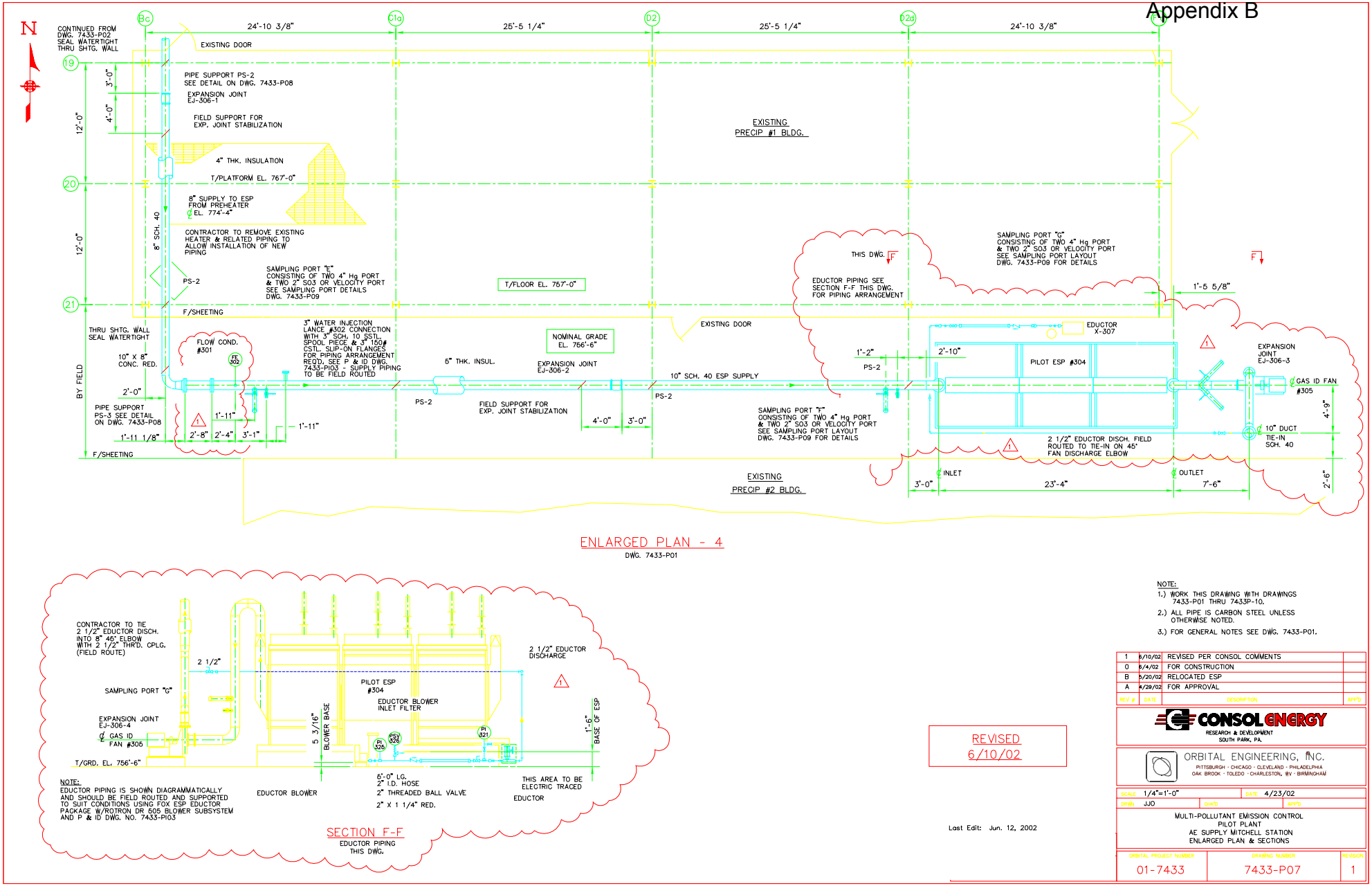


Figure B-11. General Arrangement & Piping, Enlarged Section View



ENLARGED PLAN - 4
DWG. 7433-P01

SECTION F-F
EDUCTOR PIPING THIS DWG.

NOTE:
1.) WORK THIS DRAWING WITH DRAWINGS 7433-P01 THRU 7433P-10.
2.) ALL PIPE IS CARBON STEEL UNLESS OTHERWISE NOTED.
3.) FOR GENERAL NOTES SEE DWG. 7433-P01.

REVISED 6/10/02

Last Edit: Jun. 12, 2002

REV #	DATE	DESCRIPTION	APP'D
1	6/10/02	REVISED PER CONSOL COMMENTS	
0	6/4/02	FOR CONSTRUCTION	
B	5/20/02	RELOCATED ESP	
A	4/29/02	FOR APPROVAL	

CONSOL ENERGY
RESEARCH & DEVELOPMENT
SOUTH PARK, PA.

ORBITAL ENGINEERING, INC.
PITTSBURGH · CHICAGO · CLEVELAND · PHILADELPHIA
OAK BROOK · TOLEDO · CHARLESTON, WV · BIRMINGHAM

SCALE	1/4"=1'-0"	DATE	4/23/02
DRWN	JJO	CHK'D	APP'D

MULTI-POLLUTANT EMISSION CONTROL
PILOT PLANT
AE SUPPLY MITCHELL STATION
ENLARGED PLAN & SECTIONS

ORBITAL PROJECT NUMBER	DRAWING NUMBER	REVISION
01-7433	7433-P07	1

Figure B-12. General Arrangement & Piping, Enlarged Plan & Section Views

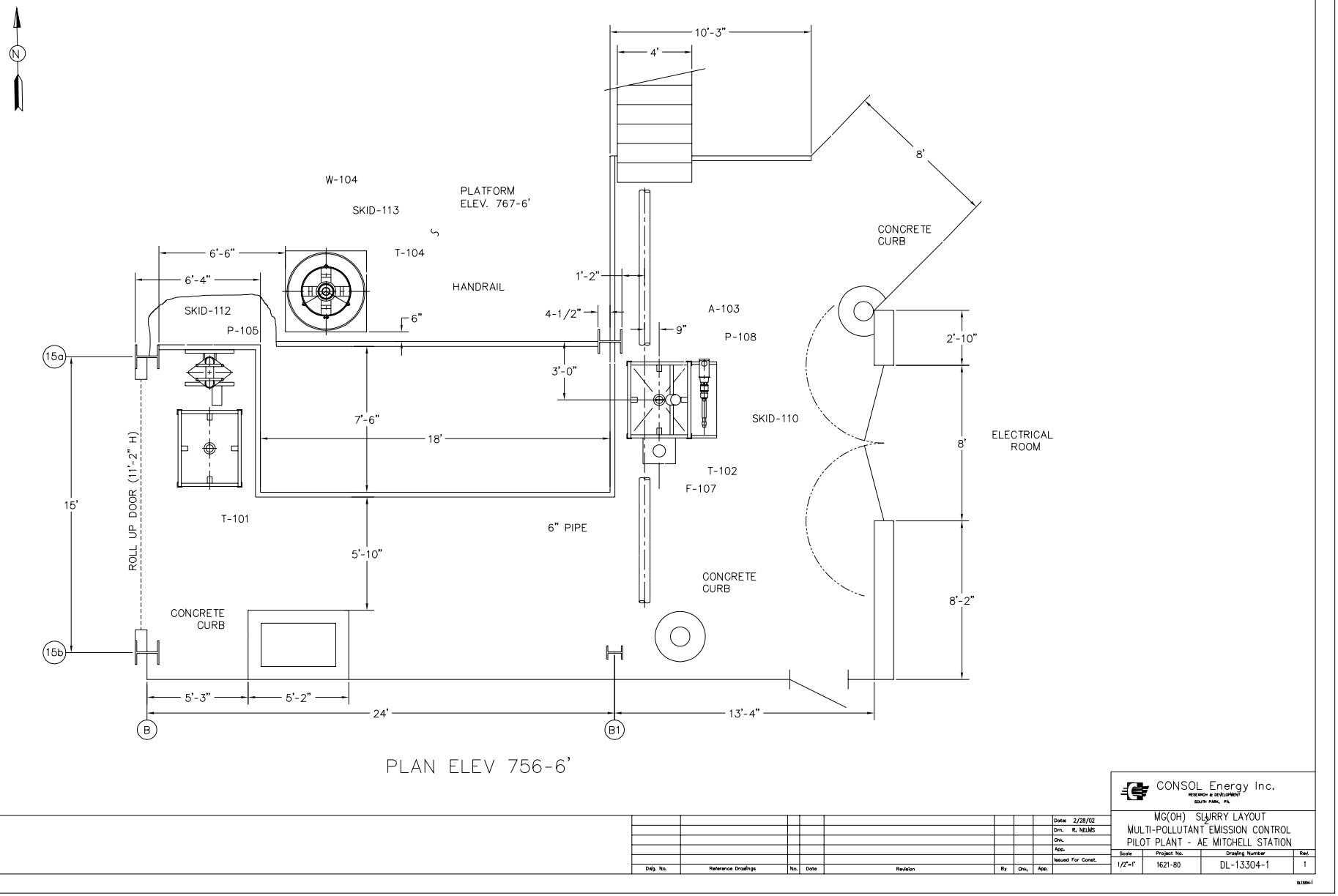


Figure B-13. General Arrangement, Enlarged Plan View of Mg(OH)2 Area

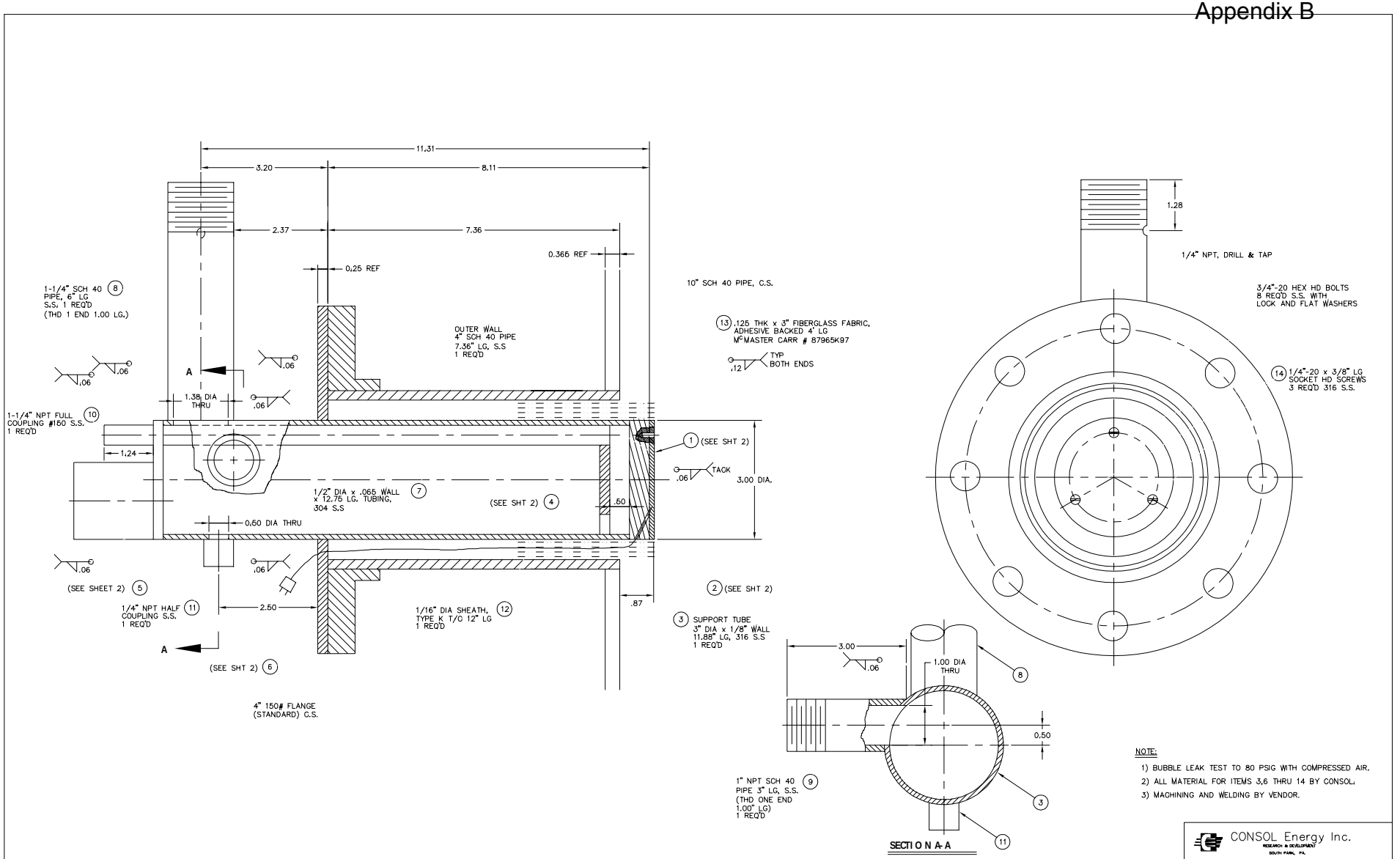


Figure B-14. Assembly, Temperature-Controlled Corrosion Probe

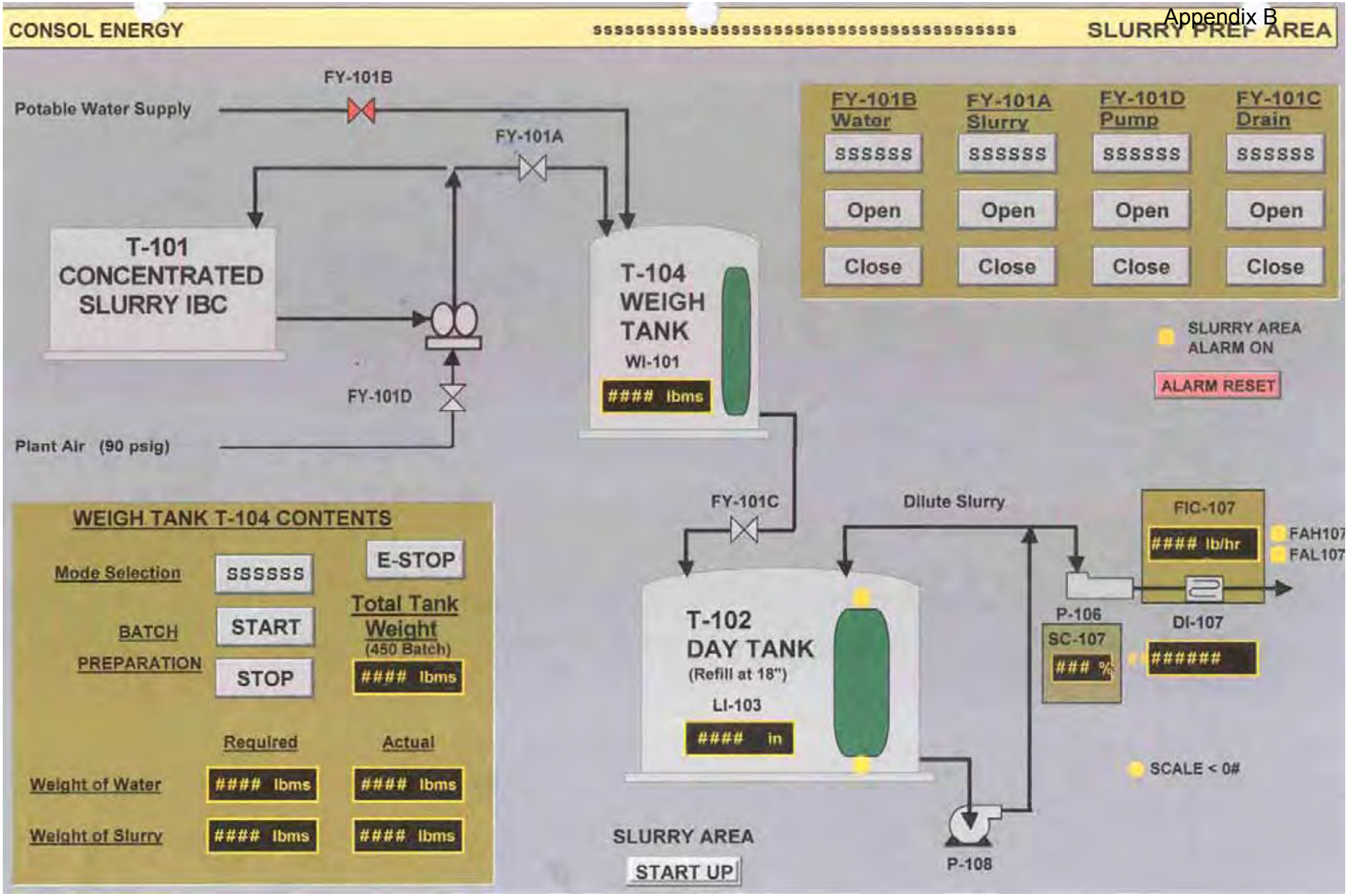


Figure B-15. Process Display Screen, Slurry Prep Area

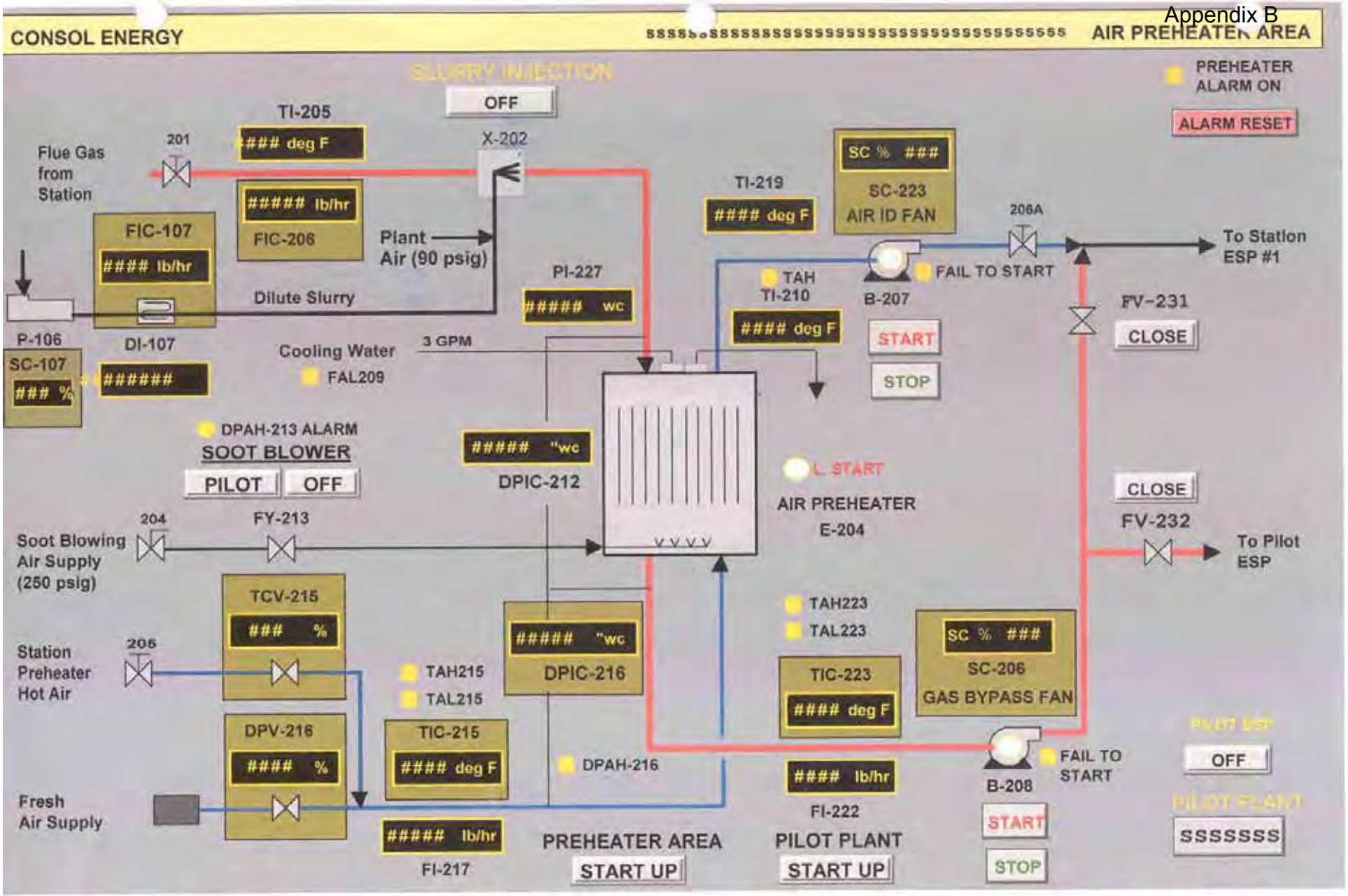


Figure B-16. Process Display Screen, Air Heater Area

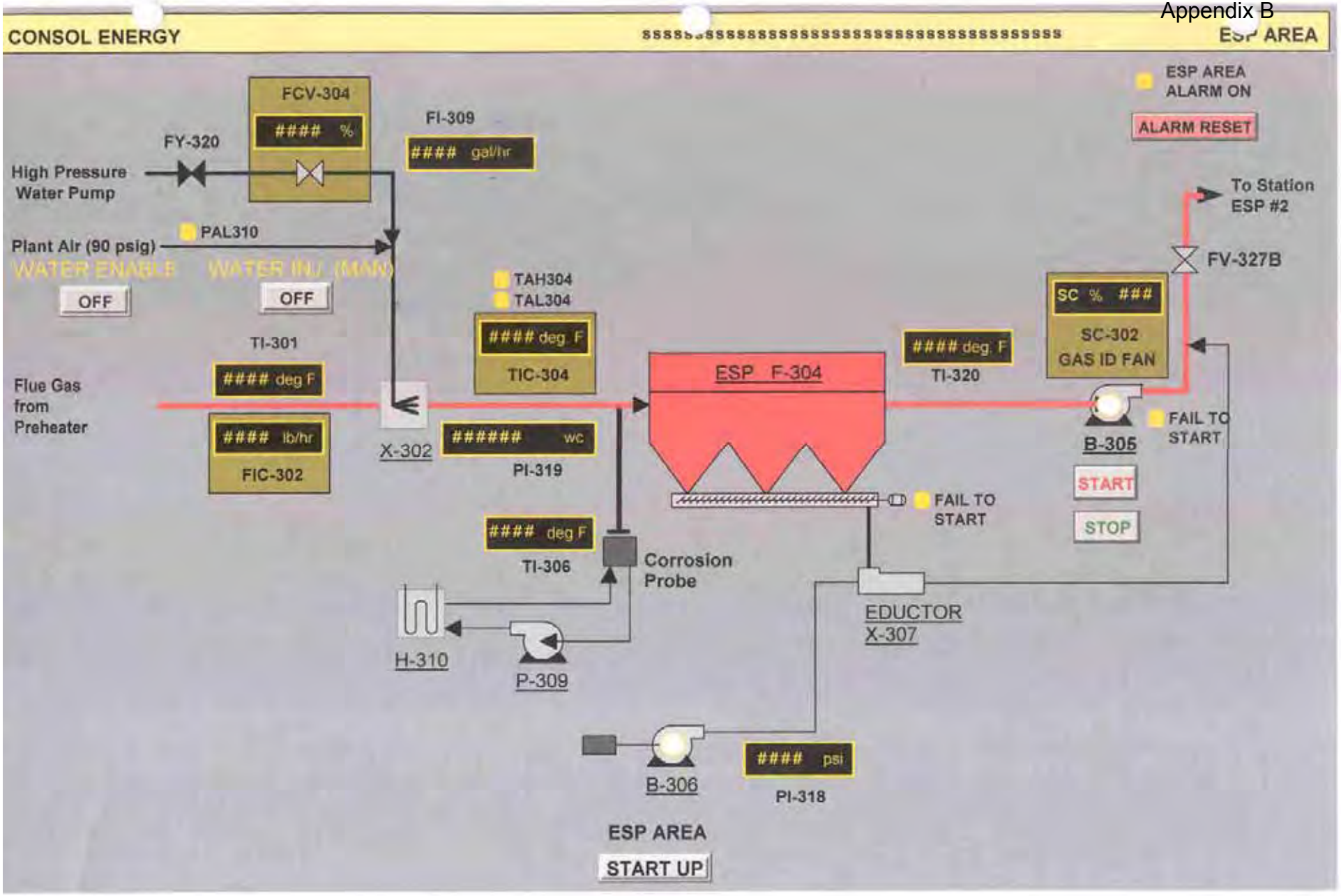


Figure B-17. Process Display Screen, ESP Area

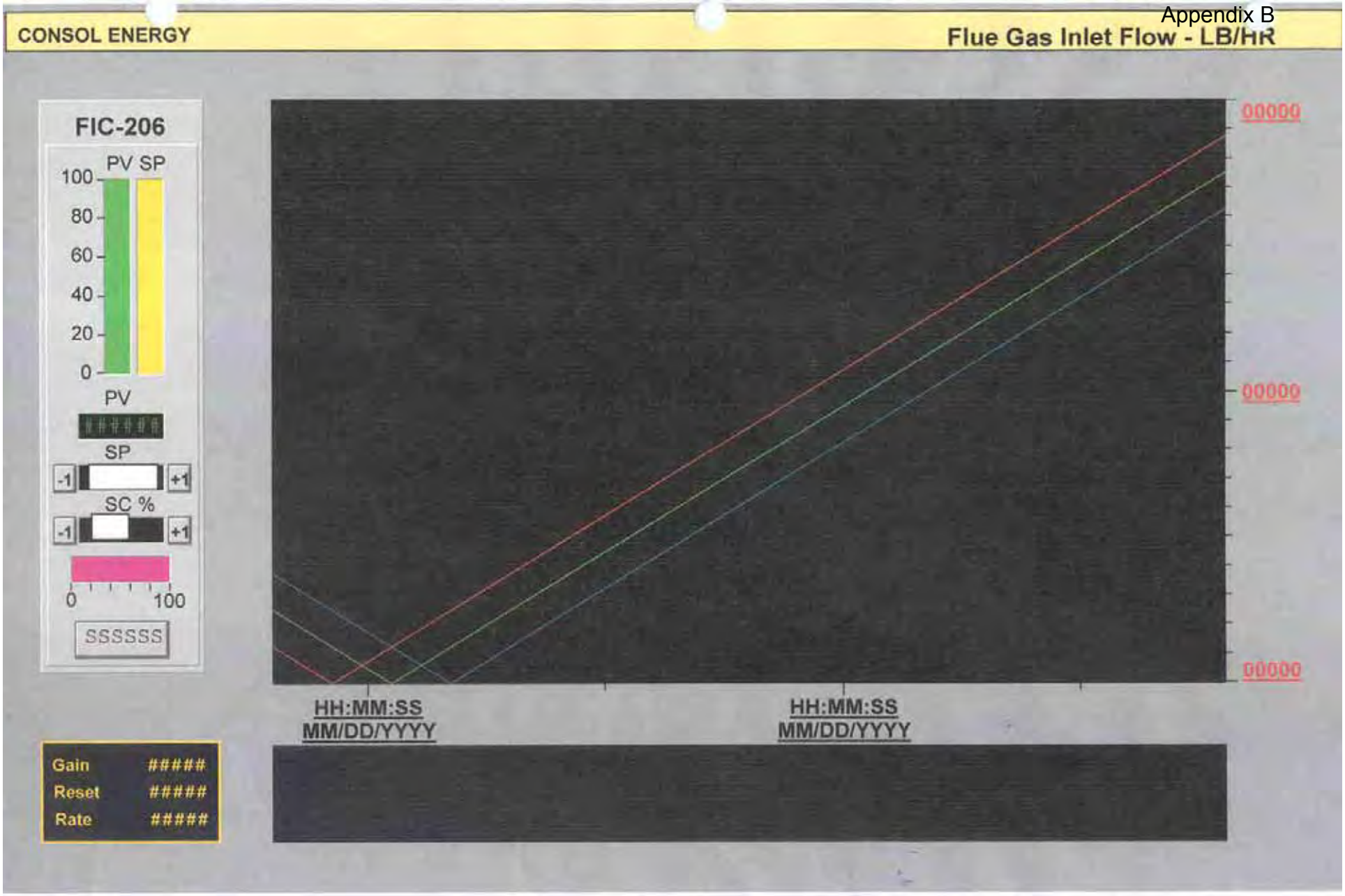


Figure B-18. Process Controller Screen

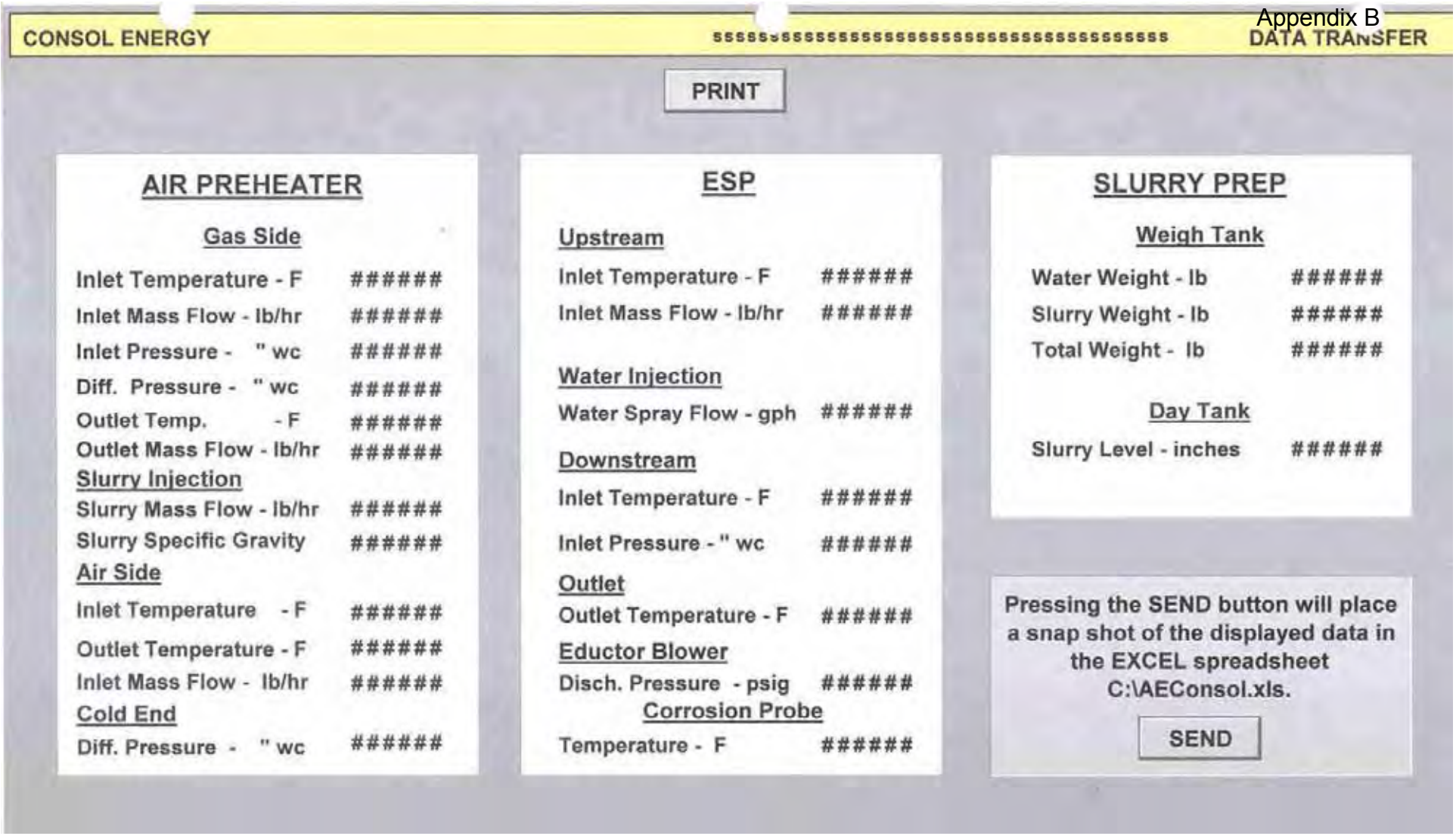


Figure B-19. Data Transfer Screen

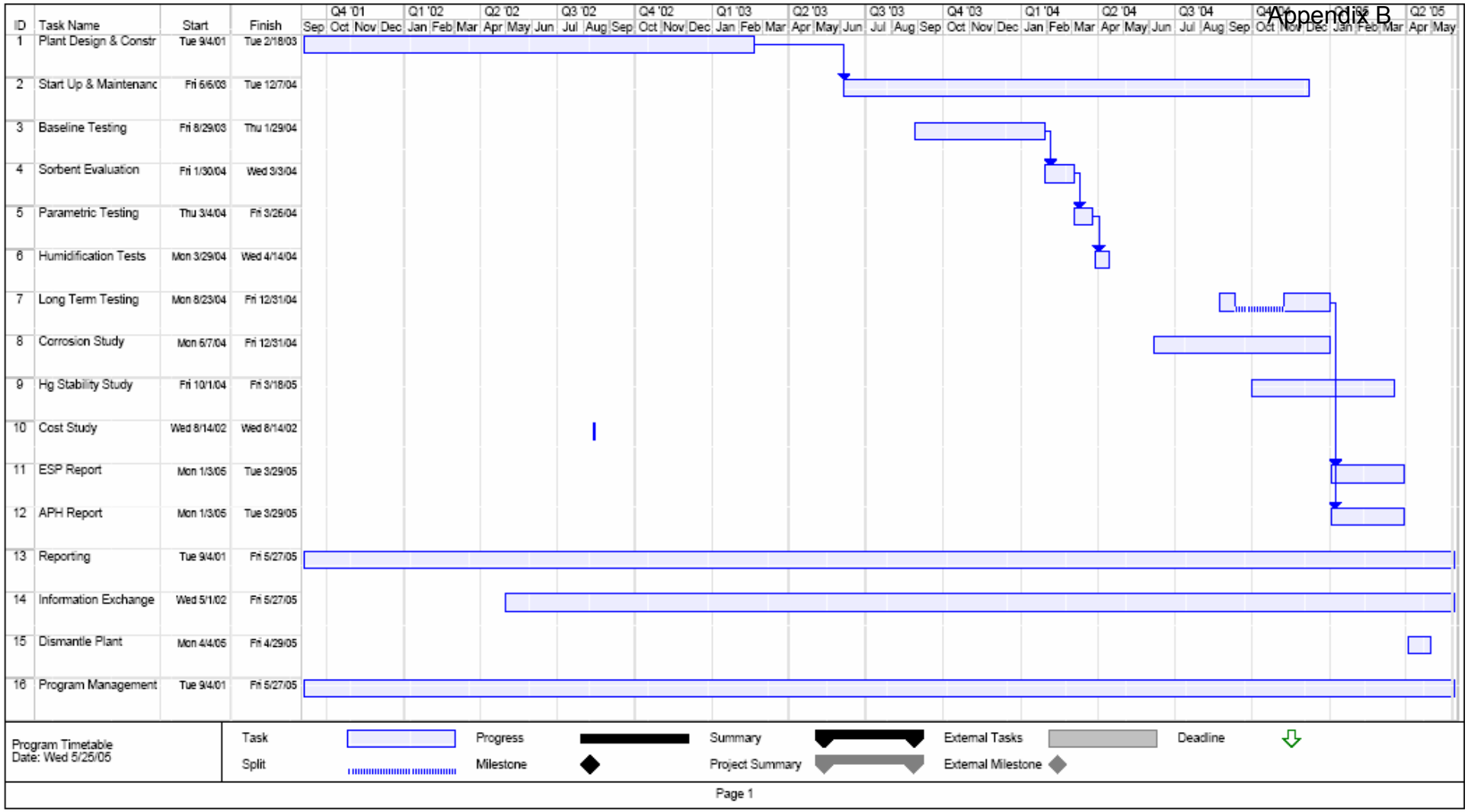


Figure B-20. Project Timetable

	MAJOR EQUIPMENT LIST				
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station				
AREA	QTY	EQUIP #	DESCRIPTION	VENDOR	REFERENCE (Drg, DSR, Part #)
100	8	T-101	400 gallon IBC, polyethylene, 2" drain	Process/Kana	Drg. DL-13304-1, Rev. 1
Mg(OH)2					
Slurry	1	T-102	360 gallon Day Tank, Plastic, Flat Bottom	Process/Kana	Drg. DL-13304-1, Rev. 1
	1	A-103	Agitator for T-102, 1/2 hp, 115/230v, 1-phase	Process/Kana	ALSOP B-547-1
	1	T-104	65 Gallon Weight Tank, Plastic, Cone Bottom	Harrington	Part # 156 Synder Ind.
	1	P-105	Transfer/Circulation Pump, 2" diaphragm	Harrington	Graco Husky M/N 2150
					Part # DF6666
	1	P-106	P.C. Pump with V.S. Drive, 1/2 hp, 115v, 1 phase	PCF Sales	Seepex Pump: 006-12MD
					Seepex 23-6125-00
	1	F-107	1/16" Filter, Duplex	Harrington	
	1	W-104	Platform Scale, 1000#, 4-20 ma, 30" x 30"	Ohio Valley	
			Mounted on Steel Base		
	1	P-108	Circulation Pump, 1 hp, 115/230v, 1 phase	PCF Sales	Seepex Pump: 1-6LBN
	1	Skid-110	Dilute Slurry Day Tank with Pump, Filter, Agitator	CONSOL	Drg. DL-13304-1, Rev. 1
			A-103, T-102, P-108, F-107, PI-105, PI-106, LT-103		CONSOL Hand Sketches
			PCV-226, FE-202 Mounted on One Skid		
	1	Skid-111	Dilute Slurry Feed Pump with Flowmeters	CONSOL	CONSOL Hand Sketches
			P-106, FT-107, SC-108, PI-113, PSV-104, PI-201		
			Mounted on One Skid		
	1	Skid-112	Conc. SlurryTransfer/Circulation Pump with Valving	CONSOL	Drg. DL-13304-1, Rev. 1
			P-105, PCV-110, FV-101D, FY/FV-101A		CONSOL Hand Sketches
			Mounted on One Skid		
	1	Skid-113	Wiegh Tank with Scale, Water Valving, Level Switch	CONSOL	Drg. DL-13304-1, Rev. 1
			T-104, W-104, LSH-102, FY/FV-101C		CONSOL Hand Sketches
			Mounted on One Skid		

	MAJOR EQUIPMENT LIST				
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station				
AREA	QTY	EQUIP #	DESCRIPTION	VENDOR	REFERENCE (Drg, DSR, Part #)
	1	SP-2	Electrical Panel - 240/120 volt, 1 Phase, 125 Amp	Chapman	
	1		480-240/120 volt Transformer, 15 kVA	Chapman	
	1		Remote PLC - I/O Panel	ACS/A-B	
200	1	X-201	20" Flow Conditioner, for Sch. 20, 316 SS	VORTAB	V0206A,
Pilot			Mounted in 20" Prefabricated Pipe		
Air					
Heater	1	X-202	Slurry Injection Lance with Nozzle & Air Barrier	Lechler	DS-99C.024.17
			with 4-foot flex hoses		
	1	B-202	Air Barrier Blower with Filter and Flowmeter	All. Fluid Power	
			.5 hp Motor, 10-15 scfm		
	1	E-204	Pilot Air Preheater, 16,000#	ALSTOM	DSR "E-204 Air Preheater"
			-Drive Panel, V.S.,460v, 3 phase, 30 A, NEMA 4	A-B	6/20/2002
			-Access Door, 25"x25", Qty. 4		
			-Water Strainer, 1.5" FPT		
			-Air Pressure Gage, 0-400 psi, .5" NPT		
			-12 Baskets, 14"sq x 42" ht, 250#		
	1	B-207	Air I.D. Fan with Insulated Jacket & Outlet Damper,	Am. Fan	IEC4549A Rev. 0, Data Sheet
			30 hp Motor and V.S. Drive	A-B	
	1	B-208	Gas By-Pass Fan with Insul. Jacket & Outlet Damper,	Am. Fan	IEC4542A Rev. 1, Data Sheet
			40 hp Motor and V.S. Drive	A-B	
	1	H-210	Hand Winch Crane & Pillar Base Jib, 500# Cap.	McMaster	Page 1242
			Mounted on 1/2" Steel Plate		
	1	V-201	Cooling Water Controls	CONSOL	P&I 7433-PI02
			PCV-228, PI-208, FSL-209 Valve & Pipe Train		
	1	PP-2	Main Power Panel - 480 v, 3 Phase, 400 Amp,	Chapman	
			NEMA 4		

	MAJOR EQUIPMENT LIST				
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station				
AREA	QTY	EQUIP #	DESCRIPTION	VENDOR	REFERENCE (Drg, DSR, Part #)
300 Pilot	1	X-301	10" Flow Conditioner, for Sch. 40, CS	VORTAB	V0206
ESP			Model: Vortab-VIS10001100, Mounted in Prefab Pipe		
	1	F-304	Pilot ESP with Power Supply & Screw Conveyor	EEC	DSR "Pilot ESP" 6/20/02
			Preassembled except for Rappers & Hot Air Purge		
			Blowers		
	1	B-305	Gas I.D. Fan with Insul. Jacket & Outlet Damper	Am. Fan	VPC982F Rev.3, Data Sheet
			10 hp Motor and V.S. Drive	A-B	
	1	B-306	Blower for Eductor, 2.2 psig, 2.5 hp, 480v, 3-phase	Fox	615346 Rev. A
	1	X-307	2" Eductor	Fox	615345 Rev. A
	1	Skid-312	Eductor Blower and Pressure Controls	CONSOL	CONSOL Hand Sketches
			B-306, PI-325, PSV-326, PIT-318		P&I 7433-PI03
			Mounted on One Skid		
	1	X-308	Corrosion Probe, Mounts in 4" pipe at ESP Inlet	CONSOL	DM-13305-1, Rev. 1
	1	P-309	Circulation Pump, Glychol, 1/10 hp, 120v	Harrington	
	1	H-310	Circulation Heater, 750 watt, 120 v	Hy-Tech	
	1	T-311	Expansion Tank, 1/2 Gallon Plastic	CONSOL	DM-13305-1, Rev. 1
	1	Skid-313	Corrosion Probe Control Panel & Pump	CONSOL	CONSOL Hand Sketches
			P-309, H-310, X-308, T-311, TE-306		P&I 7433-PI03
			Mounted on One Skid		
	2	S-314	Corrosion Probe Access Platform	Universal	
			Steel Scaffold Kit, 5' x 7' x 15'-8" on Casters		
			Located at Sample Port F		
	1	X-302	Water Injection Lance with Nozzle & Air Barrier	Lechler	DS-99C.023.17
			with 4-foot flex hoses		

	MAJOR EQUIPMENT LIST				
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station				
AREA	QTY	EQUIP #	DESCRIPTION	VENDOR	REFERENCE (Drg, DSR, Part #)
	1	B-302	Air Barrier Blower with Filter and Flowmeter	All. Fluid Power	
			.5 hp Motor, 10-15 scfm		
	1	V-314	Compressed Air Controls for Water Injection Lance	CONSOL	P&I 7433-PI03
			PCV-328, PSL-310, PI-311, FI-312		
			Valve & Pipe Train		
	1	V-315	Water Flow Controls for Water Injection Lance	CONSOL	P&I 7433-PI03
			FV-320, FV-304, Ft/FE-309, PI-308		
			Valve & Pipe Train		
	1	Skid-316	Booster Pump & Tank for Water Injection Lance	CONSOL	
			P-302, PRV-327, PI-328		
	1	PP-1	Electrical Panel - 240/120 volt, 1 Phase, 150 Amp	Chapman	
	1		480-240/120 volt Transformer, 75 kVA	Chapman	
Trailer	1		Lab & Monitoring Equipment Trailer (8' x 20')	CONSOL	
			(230v, 1-phase, 60 amp)		
	1		Main PLC - I/O Panel	ACS/A-B	
	1		Computer, Monitor, Inkjet Printer	Dell	

	INSTRUMENT LIST						
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station						
AREA	INSTRUMENT #			EQUIPMENT #	FUNCTION	DESCRIPTION	MANUFACTURER
100	FY	101	A	P-105	Air Solenoid/Mg(OH)2	T-104 Slurry Supply	ASCO
Mg(OH)2							
Slurry	FV	101	B	T-101	Water Solenoid	T-104 Water Supply	ASCO
	FY	101	C	T-104	Air Solenoid/Mg(OH)2	T-104 Slurry Discharge	ASCO
	FV	101	D	P-105	Air Solenoid	P-105 Supply	ASCO
	WT	101		T-104	Weigh Scale	T-104 Weight	OV SCALE
	LSH	102		T-104	Point Level	T-104 High Level	FLOWLINE
	LT	103		T-102	Continuous Level	T-102 Level	FLOWLINE
	FT/DT	107		P-106 Discharge	Mass Flow/Density	Coriolis Flowmeter	E+H
	SC	108		P-106	Speed Control	P-106 Speed Signal	SEEPEX
200	TIT	205		20" Sch 20 Pipe	Temperature	Flue Gas, Inlet	Thermal Ins.
Pilot							
Air	FT	206		20" Sch 20 Pipe	Flow	Flue Gas, Inlet	Thermal Ins.
Heater							
	FSL	209		E-204, Bearing	Flow Switch	Air Preheater Water	RCM
	TIT	210		E-204, Bearing	Temperature	Air Preheater Water	Rosemount
	DPIT	212		E-204	Differential Pressure	Air Prehtr. Gas Side	Rosemount
	HS	213	B	Station Control RM	Start Cycle	Soot Blower Air	A-B or Equal
	DPHL	213		Station Control RM	High DP Light	Differential Pressure	A-B or Equal

	INSTRUMENT LIST					
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station					
AREA	INSTRUMENT #			EQUIPMENT #	FUNCTION	DESCRIPTION	MANUFACTURER
200 Pilot Air Heater	FY	213		E-204, 3" Ball Valve	Air Solenoid	Soot Blower Air	ASCO
	TCV	215		E-204, 8" Bf. Valve	Flow Valve	Hot Air	ROSE/INDELAC
	TIT	219		E-204	Temperature	Air Prehtr. Outlet Air	Rosemount
	DPIT	216		E-204	Differential Pressure	Air Prehtr. Cold End	Rosemount
	DPV	216		E-204, 8" Bf. Valve	Flow Valve	Air	ROSE/INDELAC
	FT	217		E-204	Flow	Air Prehtr. Inlet Air	Thermal Ins.
	TIT	215		E-204	Temperature	Air Prehtr. Inlet Air	Thermal Ins.
	FT	222		E-204	Flow	Air Prehtr. Outlet Gas	Thermal Ins.
	TIT	223		E-204	Temperature	Air Prehtr. Outlet Gas	Thermal Ins.
	PIT	227		E-204	Pressure	Air Prehtr. Gas Inlet	Rosemount
	FY	231		FV-231, Valve	Solenoid	B-208 Bypass Gas	ASCO
	FV	232		ESP	Open-Close Relay	ESP Inlet Gas Valve	ROSE
	SC	206		B-208, VFD	Speed Control	Gas Bypass Fan	A-B
	SC	223		B-207, VFD	Speed Control	Air ID Fan	A-B
	SC	230		E-204 VFD	Local Speed Control	Air Preheater Drive	A-B

	INSTRUMENT LIST					
	Multi-Pollutant Emission Control Pilot Plant, AE Mitchell Station					
AREA	INSTRUMENT #			EQUIPMENT #	FUNCTION	DESCRIPTION	MANUFACTURER
300	TIT	301		10" Sch. 40 Pipe	Temperature	ESP Inlet Gas	Thermal Ins.
Pilot							
ESP	FT	302		10" Sch. 40 Pipe	Flow	ESP Inlet Gas	Thermal Ins.
	TIT	304		10" Sch. 40 Pipe	Temperature	Humid. ESP Inlet Gas	Rosemount
	FV	304		1/2" Pipe	Flow	X-302 Spray Water	ASCO
	TIT	306		Coupon	Temperature	Corrosion Probe	WATLOW
	FT	309		1/2" Pipe	Flow	Transmitter	SPARLING
	PSL	310		1/2" Pipe	Air Pressure	X-302 Spray Water	CCS
	PIT	318		Eductor X-307	Pressure	Eductor Inlet Pressure	Rosemount
	PIT	319		ESP	Pressure	F-304 Inlet Pressure	Rosemount
	FV	320		1/2" Pipe	Solenoid	X-302 Spray Water	ASCO
	TIT	320		10" Sch. 40 Pipe	Temperature	ESP Outlet Gas	ROSEMOUNT
	R	322		ESP Conveyor	Start/Run Interlock	ESP Screw	A-B or Equal
	SS	323		ESP Conveyor	Open-Close Relay	ESP Screw Speed Sw.	CONTROL CONC.
	XS	324		B-306, Blower	Aux. Contract	B-306 Running	ALLEN-BRADLEY
	SC	302		B-305, VFD	Speed Control	Gas ID Fan, ESP	A-B

DESIGN ENGINEERING AND CONSTRUCTION - TASK 1 (10/5/01 thru 2/18/03)

Date	Major Milestones
10/5/01	Project kick-off meeting at NETL
11/1/01	Planning meetings between Allegheny Energy and CONSOL at Mitchell Power Station
11/15/01	Agreement between Allegheny Energy and CONSOL for pilot plant installation at Mitchell Power Station completed
12/15/01	Alstom Power subcontract for pilot air heater initiated
1/2/02	Preliminary process flowsheets issued
1/7/02	Flue gas velocity measurements at economizer outlet completed in order to locate flue gas extraction pipe
2/21/02	Environmental Elements subcontract for pilot ESP initiated
2/28/02	General arrangement drawings of pilot plant completed by S/D engineers
3/15/02	Orbital Engineering selected to provide civil, structural, piping, electrical, P&I, design drawings and control system programming for pilot plant construction
4/1/02	Procurement of fans, spray lances and other major mechanical equipment started
5/22/02	Duct penetrations, valving and tie-in piping installed at Mitchell Power Station
7/15/02	Civil, structural, piping, electrical and P&I design drawings were completed by Orbital Engineering
7/30/02	Procurement of instrumentation completed
8/16/02	Piping detail drawings completed
8/16/02	Purchase order for structural steel issued
8/30/02	Pilot plant construction specifications issued for bid
9/1/02	Purchase order for pipe fabrication issued
10/4/02	Chapman Corp. selected to start construction on October 21
1/16/03	Chapman Corp. completed construction
2/18/03	Main electrical power connection completed

START UP AND MAINTENANCE - TASK 2 (2/24/03 thru 1/5/05)

Date	Major Milestones
2/24/03	Commissioning of instrumentation, electrical and mechanical eqipment started
3/15/03	PLC programming started
3/5/03	Installation of clean out ports at tie-in locations
4/24/03	Flue gas circulated through air heater for first time and start of flowmeter repairs
6/26/03	Pilot ESP start up by Environmental Elements and repairs
8/22/03	Operating/Safety Manual issued
8/29/03 thru 1/5/05	Pilot ESP repairs, flowmeter repairs, PLC programming upgrades, slurry injection lance modifications, water spray lance modifications, expansion joint repairs, flyash sampler repairs

Table B-5

PILOT PLANT OPERATION - TASK 3 (8/29/03 thru 1/30/04)

Date	Air Heater Time	Air Heater Run Time	Air Heater Gas Outlet - B °F	ESP Inlet - Loc. F °F	Sampling Program
		Gas In = 14,785 #/hr			
8/29/03	9:44:00	7 hrs, 0 min, 0 sec	310	300	AHF
	16:44:00				
		Gas In = 14,785 #/hr			
9/17/03	09:11:49				
9/18/03	15:18:19	30 hrs, 6 min, 30 sec	310	300	
		Gas In = 14,978 #/hr			
9/25/03	09:18:25				
10/7/03		311 hrs, 28 min, 54 sec	310*	300	AHF
10/8/03	08:47:13				
		Gas In = 14,978 #/hr			
10/9/03	12:59:31				
10/24/03	09:29:02	332 hrs, 29 min, 57 sec	310	297**	
		Gas In = 14,978 #/hr			
11/10/03	09:09:44				
11/18/03	08:20:33	167 hrs, 10 min, 44 sec	310	295	
		Gas In = 14,978 #/hr			
12/11/03	09:23:19				
12/13/03	05:22:14	43 hrs, 58 min, 55 sec	317	294	
		Gas In = 15,507 #/hr			
12/15/03	08:29:24				
12/16/03					AHF
12/17/03		105 hrs, 53 min, 41 sec	320	296 (279)	Hg
12/19/03	18:23:05		319	297 (292)	SO3
		Gas In = 15,507 #/hr			
1/19/04	08:59:35				
1/20/04			320		SO3
1/21/04		123 hrs, 6 min, 33 sec	320 (316)	295	SO3
1/24/04	12:06:08				
		Gas In = 15,507 #/hr			
1/27/04	08:56:10				PSD
1/28/04					PSD
1/29/04		77 hrs, 10 min, 17 sec	320 (303)	295 (290)	Hg
1/30/04	14:06:27				
2/9/04		Removed 1 Set of Baskets			
Sootblowing Frequency 8 hours		**Total** 1198 hrs, 24 min, 31 sec	**Average** 315.09		
		Average 133 hrs			

**Temperatures fluctuated between 345 and 275; the average value is 310*

***Initial and stable temperature of 297 is indicative of sampling period*

( ) - Average sample run temperature

Hg - Mercury Testing

SO3 - Sulfur Trioxide

PSD - Particle Size Distribution

AHF - Air Heater Flows

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PILOT PLANT OPERATION - TASK 4,5,6 (2/1/04 thru 4/13/04)

	Air Heater	Air Heater	Mg(OH)2 Slurry Injection	Mg(OH)2 Slurry Injection	Molar Ratio Mg(OH)2 : SO3	Air Heater Gas Outlet - B	ESP Inlet - F	Sampling Program
Date	**Time**	**Run Time**	**Time**	**Run Time**	**mol/mol**	**°F**	**°F**	
Task 4		Gas In = 14,575 #/hr						
2/23/04	10:28:05					300		
2/24/04			09:38:09 - 16:18:12	6 hrs, 40 min,	1.92	250	236 (235)	Hg
2/25/04						300		
2/26/04						300		
2/27/04			08:38:25 - 16:08:26	7 hrs, 30 min,	1.91	250	237 (238)	PSD, Hg
2/28/04		242 hrs, 47 min, 5 sec				300		
2/29/04						300		
3/1/04			08:48:39 - 15:38:40	6 hrs, 50 min,	1.9	250	236 (239)	PSD, Hg
3/2/04			08:38:44 - 17:48:47	9 hrs, 10 min,	1.74	250 (253.3)	230	AHF, SO3
3/3/04			09:48:51 - 16:38:52	6 hrs, 50 min,	4.05	250 (240)	212	SO3
3/4/04	13:15:37					300		
Task 5		Gas In = 14,575 #/hr						
3/23/04	8:28:28					300		
3/24/04		58 hrs, 50 min, 15 sec	09:08:34 - 16:38:37	7 hrs, 30 min,	4.05	234	220 (230)	Hg
3/25/04	19:18:43		08:38:40 - 18:08:42	9 hrs, 30 min,	3.76	234	221 (233.5)	Hg
Task 6		Gas In = 14,575 #/hr						
3/30/04	13:37:28					300		
3/31/04		53 hrs, 30 min, 15 sec	10:07:32 - 16:17:36	6 hrs, 10 min,	no sample	309	240	
4/1/04	19:07:43		08:17:39 - 18:37:42	10 hrs, 20 min,	3.49	314	240 (249)	Hg
						300		
		Gas In = 14,575 #/hr						
4/12/04	10:02:19					300		
4/13/04	21:12:26	35 hrs, 10 min, 07 sec	07:12:23 - 20:22:26	13 hrs, 10 min,	3.43	314	240 (250)	Hg
8/9/04		Removed 1 Set of Baskets						
Sootblowing Frequency		**Total**		**Total**		**Average**	**Average**	
8 hours		390 hrs, 17 min		83 hrs, 40 min		265.5	231	
		Average		**Average**				
		97 hrs, 30 min		8 hrs, 22 min				

( ) - Average sample run temperature
Hg - Mercury Testing
SO3 - Sulfur Trioxide
PSD - Particle Size Distribution
AHF - Air Heater Flows

Table B-7

PILOT PLANT OPERATION - TASK 7 (4/14/04 thru 12/23/04)

Appendix B

Date	Air Heater Time	Air Heater Run Time	Mg(OH)2 Slurry Injection Time	Mg(OH)2 Slurry Injection Run Time	Molar Ratio $Mg(OH)_2 : SO_3$ mol/mol	Air Heater Gas Outlet - B °F	ESP Inlet - Loc. F °F	AH Photo	Sampling Program
		Gas In = 14,631 #/hr							
8/23/04	9:44:00					300			
8/24/04			08:54-15:55	6 hrs, 10 min	4.4*	230	225		
8/25/04		78 hrs, 11 min	09:15-17:04	7 hrs, 49 min	3.16*	230	223		FL
8/26/04	15:55					300			
		Gas In = 14,631 #/hr							
8/30/04	13:00								
8/31/04			8:30 to		4.56*	230	219		FL
9/1/04		87 hrs, 4 min	14:00	29 hrs, 30 min	4.97*	230	219		FL
9/2/04			8:30 to		5.05*	230	219		FL
9/3/04	15:04		15:00	30 hrs, 30 min	5.05*	230	219		FL
		Gas In = 14,631 #/hr							
9/7/04	11:00		15:15		~4	230	219		FL
9/8/04		55 hrs	to		26.83**	230	219(198)		Hg, SO3
9/9/04	18:00		17:17	50 hrs, 2 min	4.45**	230	219(210)		Hg, SO3
		Gas In = 14,000 #/hr						30-Nov	
12/7/04	11:00		1:30 to		4.69*	230	218		
12/9/04	6:00	43 hrs	6:00	40 hrs, 30 min	4.34*	230	218		
		Gas In = 13,561 #/hr							
12/9/04	8:30		9:30 to		4.34*	230	218		FL
12/10/04	16:00	31 hrs, 30 min	16:00	30 hrs, 30 min	4.37*	230	218		FL
		Gas In = 13,561 #/hr							
12/14/04	12:00		13:15		~4	230	215	14-Dec	
12/15/04			to		20.98**	230	215		Hg, SO3
12/16/04		75 hrs			4.02**	230/250	215		Hg, SO3
12/17/04	15:00		15:00	73 hrs, 45 min	4.11*	250/270	215		Hg
		Gas In = 11,390 #/hr							
12/22/04	11:30		11:47 to		3.89*	270/240	220	22-Dec	FL
12/23/04	11:30	24 hrs	11:30	23 hrs, 13 min	3.59*	240/217	220	23-Dec	
1/3/05		Removed 1 Set of Baskets							
Sootblowing Frequency		**Total**		**Total**		**Average**	**Average**		
8/23-9/9/04 - 8 hours		393 hrs, 45 min		291 hrs, 29 min		233	219		
12/7-23/04 - 74,75,24 hours		**Average** 56 hrs		**Average** 32 hrs, 23 min					

( ) - Average sample run temperature

Hg - Mercury Testing

SO3 - Sulfur Trioxide

PSD - Particle Size Distribution

AHF - Air Heater Flows

FL - Flyash Sample

* - Based on Average SO_3 of 22 _PPMv

** - Based on Actual SO_3

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CORROSION PROBE & COUPON OPERATION AT ESP INLET AND OUTLET - TASK 3 thru 7

Date	Time	Run Time	Slurry Injection	Water Spray	INLET (loc. F) #/hr	INLET (loc. F) °F	OUTLET (loc. G) °F
Task 3							
9/10/03		Installed 150 °F heated probe coupon #0 at ESP Inlet					
9/10/03		Installed 3-corrosion coupons at ESP Outlet					
9/17/03	11:39					300	290
9/17/03	14:17					300	290
9/18/03	10:05					300	290
9/18/03	14:55	30 hr				300	290
9/25/03	16:01					300	290
9/26/03	8:21					300	290
9/29/03	10:00					300	290
9/30/03	11:30					300	290
10/1/03	9:40					300	290
10/3/03	13:35					300	290
10/7/03	13:35	311 hr				300	290
11/11/03	8:25					300	290
11/13/03	14:00					300	290
11/17/03	8:00	144 hr				300	290
12/11/03	15:34					300	290
12/12/03	8:41				3960	289	279
12/12/03	15:55	24.5 hr			3960	300	290
12/16/03	14:33				4000	300	290
12/19/03	8:30				4000	300	290
12/19/03	16:03	73.5 hr				300	290
1/19/04	15:30					300	290
1/20/04	8:50					300	290
1/20/04	16:00					300	290
1/22/04	9:45					300	290
1/24/04		100 hr					
1/28/04	15:30				4287	300	290
1/28/04	9:36				4287	300	290
1/29/04	17:30	26 hr			4287	300	290

ELAPSED TIME - hr	RUN TIME - hr
2640	709

Date	Time	Run Time	Slurry Injection	Water Spray	INLET (loc. F) #/hr	INLET (loc. F) °F	OUTLET (loc. G) °F
2/19/04		Installed 150 °F heated probe coupon #1 at ESP Inlet					
Task 4							
2/23/04	15:30				3600	287	
2/24/04	10:10		yes		3600	280	247
2/24/04	15:25		yes		3600	236	
2/27/04	9:15		yes		3600	259	247
2/27/04	16:50				3600	285	
3/1/04	9:30		yes		3600	248	251
3/1/04	10:05		yes		3600	240	251
3/1/04	15:30		yes		3600	243	251
3/2/04	8:00	185 hr			3600	282	
Task 5							
3/23/04	17:00						
3/24/04	10:30		yes		3700		210
3/24/04	12:30		yes		3700	220	210
3/24/04	15:16		yes		3700	220	210
3/24/04	17:30				3700	282	210
3/25/04	8:00				3700	281	215
3/25/04	10:54	29 hr	yes		3700	222	219
Task 6							
3/31/04	12:23		yes	yes	3800	286	280
3/31/04	15:50	3.4 hr					
4/1/04	9:00						
4/1/04	15:38		yes	yes	3800	240	219
4/1/04	18:00	9 hr					
4/13/04	9:00		yes	yes	3800		
4/13/04	9:45		yes	yes	3800	240	220
4/13/04	17:00		yes	yes	3800	240	220
4/13/04	18:32		yes		3800	280	
4/13/04	19:53	11 hr	yes		3800	290	

ELAPSED TIME - hr	RUN TIME - hr
1272	237

Date	Time	Run Time	Slurry Injection	Water Spray	INLET (loc. F) #/hr	INLET (loc. F) °F	OUTLET (loc. F) °F
Task 7							
8/24/04	9:48		yes		4100	207	220
8/24/04	10:55		yes		4100	218	220
8/24/04	14:30	5 hr	yes		4100	220	220
8/25/04	10:20		yes		4100	201	221
8/25/04	14:40	6.5 hr	yes		4100	223	221
8/31/04	10:00		yes		4100	207	219
8/31/04	15:20		yes		4100	215	218
9/1/04	8:30		yes		4100	216	217
9/1/04	14:00	28 hr			4100	220	220
9/2/04	10:00		yes		4100	209	219
9/2/04	13:22		yes		4100	219	219
9/3/04	8:35		yes		4100	216	219
9/3/04	12:46	29 hr	yes		4100	219	219
9/7/04	16:10		yes		4100	210	217
9/8/04	9:00		yes		4100	218	217
9/8/04	15:15		yes		4100	218	222
9/9/04	9:50		yes		4100	218	223
9/9/04	13:15		yes		4100	219	223
9/9/04	16:50	49 hr	yes		4100	221	223
12/7/04	14:41		yes		4100	221	215
12/8/04	8:30		yes		4100	218	216
12/9/04	15:21		yes		4200	215	212
12/10/04	8:42		yes		4200	213	212
12/10/04	9:00		yes		4200	213	212
12/10/04	13:15		yes		4200	220	211
12/10/04	15:33	69 hr	yes		4200	204	215
12/14/04	14:05		yes		4200	208	200
12/15/04	8:30		yes		4200	215	201
12/15/04	17:15		yes		4200	217	203
12/16/04	8:00		yes		4200	214	206
12/16/04	15:19		yes	yes	4200	215	207
12/17/04	8:45		yes	yes	4200	214	207
12/17/04	10:50		yes	yes	4200	220	207
12/17/04	14:30	72 hr	yes	yes	4200	215	207
12/22/04	14:05		yes		4200	238	213
12/22/04	15:30	2 hr	yes	yes	4200	216	213
1/5/05		Removed 150 °F heated probe coupon #1 at ESP Inlet					
1/5/05		Removed 3-corrosion coupons at ESP Outlet					

ELAPSED TIME - hr	RUN TIME - hr
6384	260

GRAND TOTALS	ELAPSED TIME - hr	RUN TIME - hr
3-corrosion coupons at ESP Outlet	10296	1206
150 °F heated probe coupon #0 at ESP Inlet	2640	709
150 °F heated probe coupon #1 at ESP Inlet	7656	497

APPENDIX C

Environmental Elements Corporation (EEC) Report

PILOT ESP T/R OPERATION - TASK 3

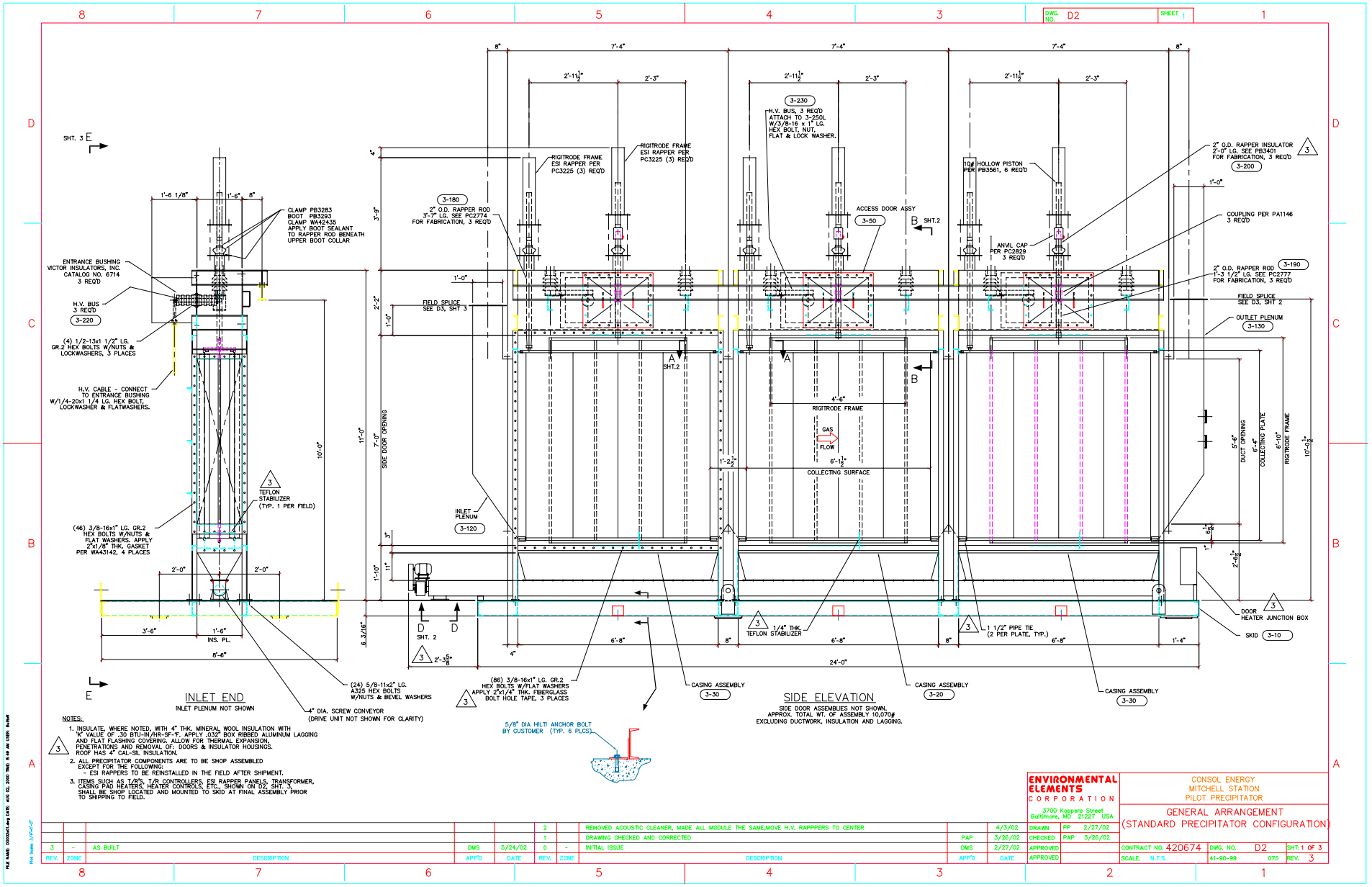
Date	Time	Run Time	INLET (loc. F) #/hr	INLET (loc. F) F	Field #1 - T/R Controller Pri. Volt	Field #1 - T/R Controller Sec. kV	Field #1 - T/R Controller Spark/Min	Field #1 - T/R Controller Sec. mA	Field #1 - T/R Controller watts	Field #1 - T/R Controller SCR Deg.	Field #2 - T/R Controller Pri. Volt	Field #2 - T/R Controller Sec. kV	Field #2 - T/R Controller Spark/Min	Field #2 - T/R Controller Sec. mA	Field #2 - T/R Controller watts	Field #2 - T/R Controller SCR Deg.	Field #3 - T/R Controller Pri. Volt	Field #3 - T/R Controller Sec. kV	Field #3 - T/R Controller Spark/Min	Field #3 - T/R Controller Sec. mA	Field #3 - T/R Controller watts	Field #3 - T/R Controller SCR Deg.	Comments
8/14-15/03		EEC Commissioned ESP and checked out operation																					
8/29/03	12:40			300	90	20	6	0		41	90	30	5	0		48	100	28	5	0		48	
8/29/03	15:51	7 hr		300	90	20	6	0		36	90	30	5	0		40	100	28	5	0		46	
9/17/03	11:39			300	80	19	6	0		36	100	29	5	0		45	90	22	6	0		36	
9/17/03	14:17			300	90	20	5	0		38	100	28	5	0		41	80	20	5	0		36	
9/18/03	10:05			300	90	20	5	0		38	90	25	5	0		42	80	20	5	0		36	
9/18/03	14:55	30 hr		300	90	20	5	0		38	90	25	5	0		42	80	20	5	0		36	
9/25/03	16:01			300	85	19	5	0		38	100	24	5	0		40	85	23	5	0		38	
9/26/03	8:21			300	90	19	5	0		38	95	23	5	0		38	85	21	5	0		38	
9/29/03	10:00			300	93	19	5	0		38	80	22	5	0		40	80	19	5	0		36	
9/30/03	11:30			300	85	19	5	0		38	80	22	5	0		38	80	18	5	0		36	
10/1/03	9:40			300	85	19	5	0		39	85	22	5	0		38	77	18	5	0		36	
10/3/03	13:35			300	90	19	5	0		38	85	25	5	0		39	75	17	5	0		35	
10/7/03	13:35	311 hr		300	90	19	5	0		41	90	24	5	0		41	75	17	5	0		35	
10/9/03	16:05			300		2		29			85	23	5	0		39	75	19	5	0		38	Under Voltage Trip #1
10/9-17/03		Troubleshooted and repaired rapper controller after many conversations with Forry																					
10/24-31/03		Opened ESP to discover that HV rapper rod insulators had failed due to sagging Teflon Barrier which allowed flyash accumulation, EEC ordered new rods and supports for Teflon Barrier																					
11/4-5/03		Installed new rapper rods and Teflon barrier supports.																					
11/11/03	8:25			300	106	21	5	0		32	85	20	5	0		38	75	19	5	0		36	Repaired rapper controller.
11/13/03	14:00			300	90	18	5	0		35	85	21	5	0		40	75	18	5	0		36	
11/17/03	8:00	144 hr		300	90	18	5	0		42	74	2	0	32		95	75	18	5	0		36	#1Tripped on Undervoltage & Reenergized
11/18-24/03		Opened ESP to find two more failed HV rapper rod insulators, EEC recommended installation of hot air purge for HV compartment, Designed and purchased equipment																					
11/25/03		EEC sent Paul Ford to troubleshoot T/R controller, Installed new resistors on T/R current measuring circuit to get a reading, Discovered broken HV bushings.																					
12/1-11/03		Replaced HV bushings and installed hot air purge and HV rapper rod heaters																					
12/11/03	15:34			300	272	52	25	2.41	125	81	218	29	25	0.97	28	62	363	57	0	5	285	108	
12/12/03	8:41		3960	289	277	52	25	2.95	153	81	219	27	25	1.11	30	62	140	30	25	0.9	27	55	
12/12/03	15:55	24.5 hr	3960	300	275	52	25	2.7	140	81	250	27	25	1.1	30	61	140	30	23	1	30	55	
12/16/03	14:33		4000	300	275	53	25	2.9	154	87	193	24	25	0.88	21	57	130	27	22	1	27	54	
12/19/03	8:30		4000	300	220	40	24	2	80	75	232	27	25	1.15	31	65	125	28	25	0.9	25	56	
12/19/03	16:03	73.5 hr		300	112	26	25	0.5	13	42	230	28	25	0.9	25	64	130	28	23	0.8	22	52	
1/5-16/04		Replaced HV bushings #1 and #3, Replaced solid connection from bushing to HV grid with a flex connector, Reduced rapping force, Replaced #2 HV grid support insulators																					
1/19/04	15:30			300	258	52	25	1.9	99	75	278	32	25	1.28	41	75	369	58	0	5.01	291	109	Purge Air Temp. 200 F
1/20/04	8:50			300	237	47	26	1.9	89	73	258	29	25	1.4	41	71	105	24	24	0.6	14	44	#3 HV Bushing may have failed
1/20/04	16:00			300	260	52	24	2.5	130	76	260	29	24	1.31	38	69	123	27	25	0.8	22	51	
1/22/04	9:45			300	263	52	25	2.7	140	80	222	26	25	1.15	30	63	132	28	22	1	28	58	
1/24/04		100 hr																					
1/28/04	15:30		4287	300	274	52	25	3.16	164	84	215	24	25	1.13	27	62	130	27	19	0.9	24	54	
1/28/04	9:36		4287	300	278	52	25	2.9	151	82	282	30	25	1.6	48	74	120	32	20	1.5	48	54	
1/29/04	17:30	26 hr	4287	300	278	52	25	2.6	135	80	235	25	25	1.21	30	64	125	32	22	1.5	48	60	
2/2-16/04		Trouble-shooted #2 T/R set, Replaced HV bushing #3																					

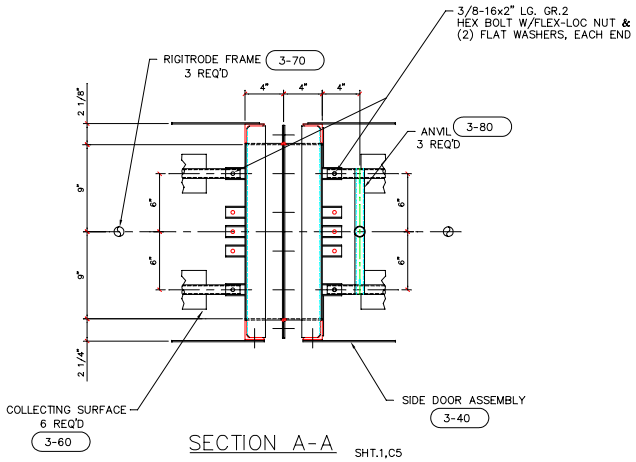
PILOT ESP T/R OPERATION - TASK 4,5,6

Date	Time	Run Time	Slurry Injection	Water Spray	INLET (loc. F) #/hr	INLET (loc. F) F	Field #1 - T/R Controller Pri. Volt	Field #1 - T/R Controller Sec. kV	Field #1 - T/R Controller Spark/Min	Field #1 - T/R Controller Sec. mA	Field #1 - T/R Controller watts	Field #1 - T/R Controller SCR Deg.	Field #2 - T/R Controller Pri. Volt	Field #2 - T/R Controller Sec. kV	Field #2 - T/R Controller Spark/Min	Field #2 - T/R Controller Sec. mA	Field #2 - T/R Controller watts	Field #2 - T/R Controller SCR Deg.	Field #3 - T/R Controller Pri. Volt	Field #3 - T/R Controller Sec. kV	Field #3 - T/R Controller Spark/Min	Field #3 - T/R Controller Sec. mA	Field #3 - T/R Controller watts	Field #3 - T/R Controller SCR Deg.	Comments
Task 4																									
2/23/04	15:30				3600	287	274	52	25	2.34	122	82	198	24	25	0.86	21	57	361	56	0	5.02	281	105	
2/24/04	10:10		yes		3600	280	269	52	25	3	156	80	208	22	25	0.9	20	58	359	55	0	5	275	104	
2/24/04	15:25		yes		3600	236	254	50	25	0.21	11	78	210	23	25	0.98	23	59	360	56	0	5.01	281	107	
2/27/04	9:15		yes		3600	259	293	53	25	0.23	12	95	220	21	25	1.1	23	61	360	55	0	5.01	276	107	
2/27/04	16:50				3600	285	280	52	25	0.18	9	83	200	18	25	0.8	14	58	358	55	0	5.03	277	104	
3/1/04	9:30		yes		3600	248	310	54	25	0.18	10	93	202	17	25	0.87	15	57	30	3	0	5.02	15	58	
3/1/04	10:05		yes		3600	240	338	56	25	0.18	10	88	199	16	25	0.88	14	59	98	22	23	0.53	12	45	
3/1/04	15:30		yes		3600	243	290	53	24	0.17	9	85	163	11	25	0.56	6	50	92	22	24	0.55	12	45	
3/2/04	8:00	185 hr			3600	282	117	28	25	0.06	2	46	187	21	24	0.62	13	53	90	21	25	0.4	8	40	Undervoltage trip #1
3/8-17/04		Rebuilt ESP: Replaced #1 & #3 HV Bushings, Installed Flex Connector from Bushing to Grid, Cut Access Door in Teflon Barriers, Cleaned CP & HV Grid, Removed Teflon Spacer from HV Grids																							
3/19-23/04		EEC Replaced Failed SCR Snubber & T/R Microprocessor on #2																							
Task 5																									
3/23/04	17:00						405	55	0	1	55	139							314	47	0	20	940		No Gas Flow
3/24/04	10:30		yes		3700		396	55	6	1.09	60	118							120	14	6	17.48	245	72	Raised Thermostats to 300 F
3/24/04	12:30		yes		3700	220	400	55	2	1.08	59	117							188	34	0	10.8	367	69	Lowered #3 Sec. Current Limit to 10 mA
3/24/04	15:16		yes		3700	220	400	55	0	1	55	117							210	36	0	10	360	75	
3/24/04	17:30				3700	282	362	52	37	0.8	42	100							214	36	0	10	360	75	Slurry Inj. Stopped at 16:30
3/25/04	8:00				3700	281													231	39	0	10	390	78	Undervoltage Trip #1
3/25/04	10:54	29 hr	yes		3700	222													237	41	0	10	410	79	
3/26/04		EEC Repaired T/R Microprocessor Controller																							
3/29/04		Replaced HV Rapper Insulation Rod on #1																							
3/30/04		Adjusted T/R Microprocesser Controller on #1 & #3																							
Task 6																									
3/31/04	12:23		yes	yes	3800	286	286	54	0	15.6	842	85							257	46	0	20.1	925	87	
3/31/04	15:50	3.4 hr																							
4/1/04	9:00																								
4/1/04	15:38		yes	yes	3800	240	322	55	0	14.9	820	95							250	45	0	20.1	905	86	
4/1/04	18:00	9 hr																							
4/2/04		Opened & Inspected #1 Field, Okay																							
4/13/04	9:00		yes	yes	3800																				
4/13/04	9:45		yes	yes	3800	240	295	55	0	11.8	649	89							252	46	0	20.1	925	86	
4/13/04	17:00		yes	yes	3800	240	296	55	0	12.4	682	91							249	45	0	20.1	905	86	
4/13/04	18:32		yes		3800	280	350	55	0	17.3	952	100							255	46	0	20.1	925	87	
4/13/04	19:53	11 hr	yes		3800	290	351	55	0	13.7	754	101							256	45	0	20.1	905	87	

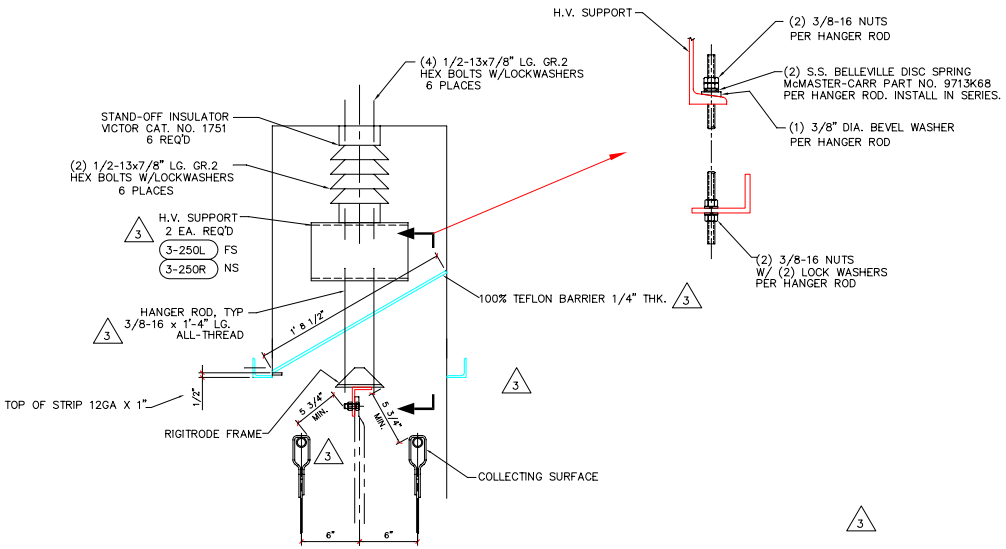
PILOT ESP T/R OPERATION - TASK 7

							Field #1 - T/R Controller						Field #3 - T/R Controller						Field #2 - T/R Controller						
Date	Time	Run Time	Slurry Injection	Water Spray	INLET (loc. F) #/hr	F	Pri. Volt	Sec. kV	Spark/Min	Sec. mA	watts	SCR Deg.	Pri. Volt	Sec. kV	Spark/Min	Sec. mA	watts	SCR Deg.	Pri. Volt	Sec. kV	Spark/Min	Sec. mA	watts	SCR Deg.	Comments
7/23-27/04		Dennis Foley of EEC performed repairs																							
8/24/04	9:48		yes		4100	207	248	50	0	4.59	230	78	245	45	0	19.6	882	85	135	25	0	3.11	78	47	
8/24/04	10:55		yes		4100	218	250	50	0	4.52	226	78	243	45	0	19.1	860	85	139	25	0	3.27	82	49	
8/24/04	14:30	5 hr	yes		4100	220	245	50	0	4.13	207	78	242	45	0	18.8	846	85	139	25	0	3.3	83	49	
8/25/04	10:20		yes		4100	201	247	50	0	4.16	208	77	241	45	0	18.2	819	84	135	25	0	3.17	79	48	
8/25/04	14:40	6.5 hr	yes		4100	223	245	50	0	3.94	197	76	239	45	0	18.1	815	83	137	25	0	3.15	79	48	Lifted CP rapper 6 times by hand at 14:3
8/31/04	10:00		yes		4100	207	246	50	0	5.49	275	77	244	45	0	19.43	874	86	137	25	0	3.29	82	48	Cleaned HV connection at T/R #1
8/31/04	15:20		yes		4100	215	244	50	0	5.23	262	78	237	45	0	17.28	778	85	1380	25	0	3.16	79	49	
9/1/04	8:30		yes		4100	216	243	50	0	4.9	245	77	238	45	0	17.4	783	83	138	25	0	2.92	73	48	
9/1/04	14:00	28 hr			4100	220	239	50	0	4.91	246	76	235	45	0	17	765	82	138	25	0	2.98	75	48	
9/2/04	10:00		yes		4100	209	239	50	0	4.98	249	76	232	45	0	16.22	730	81	138	25	0	3.16	79	48	
9/2/04	13:22		yes		4100	219	243	50	0	5.04	252	77	235	45	0	16.63	748	82	138	25	0	3.1	78	49	
9/3/04	8:35		yes		4100	216	242	50	0	5.07	254	77	234	45	0	16.05	722	82	137	25	0	2.9	73	48	
9/3/04	12:46	29 hr	yes		4100	219	242	50	0	5.03	252	77	233	45	0	15.9	716	80	136	25	0	2.88	72	48	
9/7/04	16:10		yes		4100	210	253	50	0	6.39	320	78	234	45	0	16.87	759	82	141	25	0	3.48	87	49	
9/8/04	9:00		yes		4100	218	242	50	0	4.69	235	77	235	45	0	16.3	734	83	134	25	0	2.81	70	48	
9/8/04	15:15		yes		4100	218	239	50	0	4.43	222	74	233	44	0	15.87	698	82	51	2	43	20	40	32	Field #2 Shutdown
9/9/04	9:50		yes		4100	218	251	50	0	4.48	224	78	236	45	0	17.2	774	82	Rapper Control Failed/Repaired						
9/9/04	13:15		yes		4100	219	251	50	0	4.85	243	79	236	45	0	16.9	761	82							
9/9/04	16:50	49 hr	yes		4100	221	247	50	0	4.26	213	77	233	45	0	16.2	729	81							
11/18/04		Cleaned CP & Teflon Barrier on #1				Inspection & Photos 11/22/04																			
12/7/04	14:41		yes		4100	221	251	50	0	5.28	264	77	236	45	0	17.52	788	82							
12/8/04	8:30		yes		4100	218	254	50	0	5.55	278	77	233	45	0	16.5	743	80							
12/9/04	15:21		yes		4200	215	254	50	0	6.19	310	79	235	45	0	16.8	756	81							
12/10/04	8:42		yes		4200	213	164	26	0	20.1	523	100	226	45	0	19	855	78	Rapper Control Failed Overnight/Restart at 8:00						Lowered AH Outlet to 220F at 8:30
12/10/04	9:00		yes		4200	213	270	50	0	8.71	436	85	245	45	0	19.6	882	84							Raised AH Outlet to 230F at 8:50
12/10/04	13:15		yes		4200	220	253	50	0	6.42	321	78	241	45	0	18.9	851	84							
12/10/04	15:33	69 hr	yes		4200	204	251	50	0	6.37	319	78	239	45	0	18.3	824	83							
12/14/04	14:05		yes		4200	208	244	50	0	6.21	311	77	234	45	0	16.4	738	80							
12/15/04	8:30		yes		4200	215	242	50	0	4.9	245	75	236	45	0	16.8	756	80							
12/15/04	17:15		yes		4200	217	242	50	0	5.22	261	76	234	45	0	16	720	79							
12/16/04	8:00		yes		4200	214	241	50	0	5.33	267	76	240	45	0	17.8	801	81							
12/16/04	15:19		yes	yes	4200	215	240	50	0	4.84	242	75	323	45	0	16.3	734	79	Water Spray On at 13:34, Off at 16:44						
12/17/04	8:45		yes	yes	4200	214	83	10	0	20.5	205	80	174	30	0	20.1	603	73	Water Spray On at 8:00, Off at 9:00						
12/17/04	10:50		yes	yes	4200	220	122	30	0	1.75	53	47	225	45	0	13.6	612	74	#1 Field Limited to 30 kV			Water Spray On at 10:50			Teflon Barrier depsoit shorted out field
12/17/04	14:30	72 hr	yes	yes	4200	215	121	30	0	1.68	50	46	222	45	0	13.3	599	73	#1 Field Limited to 30 kV			Water Spray Off at 14:44			Teflon Barrier depsoit shorted out field
12/20/04		Cleaned Teflon Barrier on #1 & 3				Inspection & Photos 12/20/04, Replaced Teflon barrier support on #1																			
12/22/04	14:05		yes		4200	238	244	50	0	4.91	246	76	230	45	0	15.3	689	76							
12/22/04	15:30	2 hr	yes	yes	4200	216	275	40	0	20.17	807	104	213	37	0	20.2	747	79	Water Spray On at 14:10, Off at 15:33						Teflon Barrier depsoit shorted out field

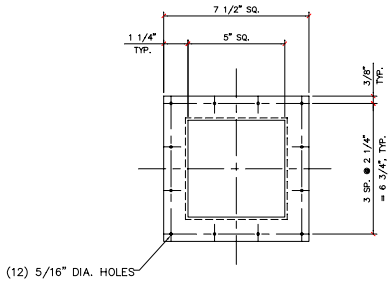

DWG. NO. D2
SHEET 1
SHT. 3 E
CLAMP PB3283
BOOT PB3293
CLAMP WA42435
APPLY BOOT SEALANT
TO RAPPER ROD BENEATH
UPPER BOOT COLLAR
ENTRANCE BUSHING
VICTOR INSULATORS, INC.
CATALOG NO. 6714
3 REQ'D
H.V. BUS
3 REQ'D
3-220
(4) 1/2-13x1 1/2" LG.
GR.2 HEX BOLTS W/NUTS &
LOCKWASHERS, 3 PLACES
H.V. CABLE - CONNECT
TO ENTRANCE BUSHING
W/1/4-20x1 1/4 LG. HEX BOLT,
LOCKWASHER & FLATWASHERS.
TEFLON
STABILIZER
(TYP. 1 PER FIELD)
(46) 3/8-16x1" LG. GR.2
HEX BOLTS W/NUTS &
FLAT WASHERS. APPLY
2"x1/8" THK. GASKET
PER WA43142, 4 PLACES
(24) 5/8-11x2" LG.
A325 HEX BOLTS
W/NUTS & BEVEL WASHERS
4" DIA. SCREW CONVEYOR
(DRIVE UNIT NOT SHOWN FOR CLARITY)
INLET END
INLET PLENUM NOT SHOWN
3-180
2" O.D. RAPPER ROD
3'-7" LG. SEE PC2774
FOR FABRICATION, 3 REQ'D
RIGITRODE FRAME
ESI RAPPER PER
PC3225 (3) REQ'D
FIELD SPLICE
SEE D3, SHT 3
SIDE DOOR OPENING
INLET
PLENUM
3-120
(86) 3/8-16x1" LG. GR.2
HEX BOLTS W/FLAT WASHERS
APPLY 2"x1/4" THK. FIBERGLASS
BOLT HOLE TAPE, 3 PLACES
5/8" DIA HILTI ANCHOR BOLT
BY CUSTOMER (TYP. 6 PLCS)
3-230
H.V. BUS, 3 REQ'D
ATTACH TO 3-250L
W/3/8-16 x 1" LG.
HEX BOLT, NUT,
FLAT & LOCK WASHER.
ACCESS DOOR ASSY
3-50
SHT.2
10# HOLLOW PISTON
PER PB3561, 6 REQ'D
ANVIL CAP
PER PC2829
3 REQ'D
RIGITRODE FRAME
GAS
FLOW
COLLECTING SURFACE
1/4" THK.
TEFLON STABILIZER
1 1/2" PIPE TIE
(2 PER PLATE, TYP.)
CASING ASSEMBLY
3-30
CASING ASSEMBLY
3-20
CASING ASSEMBLY
3-30
SIDE ELEVATION
SIDE DOOR ASSEMBLIES NOT SHOWN.
APPROX. TOTAL WT. OF ASSEMBLY 10,070#
EXCLUDING DUCTWORK, INSULATION AND LAGGING.
2" O.D. RAPPER INSULATOR
2'-0" LG. SEE PB3401
FOR FABRICATION, 3 REQ'D
3-200
COUPLING PER PA1146
3 REQ'D
2" O.D. RAPPER ROD
1'-3 1/2" LG. SEE PC2777
FOR FABRICATION, 3 REQ'D
3-190
FIELD SPLICE
SEE D3, SHT 2
OUTLET PLENUM
3-130
DUCT OPENING
COLLECTING PLATE
RIGITRODE FRAME
DOOR
HEATER JUNCTION BOX
SKID 3-10
NOTES:
1. INSULATE, WHERE NOTED, WITH 4" THK. MINERAL WOOL INSULATION WITH "K" VALUE OF .30 BTU-IN/HR-SF-°F. APPLY .032" BOX RIBBED ALUMINUM LAGGING AND FLAT FLASHING COVERING. ALLOW FOR THERMAL EXPANSION. PENETRATIONS AND REMOVAL OF: DOORS & INSULATOR HOUSINGS. ROOF HAS 4" CAL-SIL INSULATION.
2. ALL PRECIPITATOR COMPONENTS ARE TO BE SHOP ASSEMBLED EXCEPT FOR THE FOLLOWING:
- ESI RAPPERS TO BE REINSTALLED IN THE FIELD AFTER SHIPMENT.
3. ITEMS SUCH AS T-R'S, T-R CONTROLLERS, ESI RAPPER PANELS, TRANSFORMER, CASING PAD HEATERS, HEATER CONTROLS, ETC., SHOWN ON D2, SHT. 3, SHALL BE SHOP LOCATED AND MOUNTED TO SKID AT FINAL ASSEMBLY PRIOR TO SHIPPING TO FIELD.
ENVIRONMENTAL ELEMENTS CORPORATION
3700 Koppers Street
Baltimore, MD 21227 USA
CONSOL ENERGY
MITCHELL STATION
PILOT PRECIPITATOR
GENERAL ARRANGEMENT
(STANDARD PRECIPITATOR CONFIGURATION)
DRAWN PP 2/27/02
CHECKED PAP 3/26/02
APPROVED
CONTRACT NO. 420674
DWG. NO. D2
SHT: 1 OF 3
SCALE: N.T.S.
41-90-99 075
REV. 3
2 REMOVED ACOUSTIC CLEANER, MADE ALL MODULE THE SAME,MOVE H.V. RAPPPERS TO CENTER DMS 4/3/02
1 DRAWING CHECKED AND CORRECTED PAP 3/26/02
3 - AS BUILT DMS 5/24/02
0 - INITIAL ISSUE DMS 2/27/02
REV. ZONE DESCRIPTION APP'D DATE



SECTION A-A SHT.1,C5



SECTION B-B SHT.1,C3



VIEW D-D SHT.1,B6

REV.	ZONE	DESCRIPTION	APP'D	DATE
3	-	AS BUILT	DMS	5/24/02

REV.	ZONE	DESCRIPTION	APP'D	DATE
2		REMOVED SECTION C-C, REVISED SECTION B-B		4/3/02
1		DRAWING CHECKED AND CORRECTED	PAP	3/26/02
0	-	INITIAL ISSUE	DMS	2/27/02

ENVIRONMENTAL ELEMENTS CORPORATION
3700 Koppers Street
Baltimore, MD 21227 USA

DRAWN	PP	2/27/02
CHECKED	PAP	3/26/02
APPROVED		
APPROVED		

CONSOL ENERGY
MITCHELL STATION
PILOT PRECIPITATOR

GENERAL ARRANGEMENT
(STANDARD PRECIPITATOR CONFIGURATION)

CONTRACT NO. 420674 | DWG. NO. D2 | SHT: 2 OF 3
SCALE: 41-90-99 075 | REV. 3

DWG. NO. D2 SHEET 1

FILE NAME: D0002a02.dwg DATE: AUG 02, 2000 TIME: 8:5 AM USER: Butler
Print Scale:

APPENDIX D

Final Test Report
Alstom Power, Inc, Air Preheater Company
Contract: LAP 4392
PO #: 17001041471
Customer: CONSOL Energy, Inc.
April 4, 2005

Section 1: Introduction:

In December, 2001, Alstom Power, Inc, Air Preheater Co. and CONSOL Energy, 4000 Brownsville Road, South Park, Pa entered into a sub-contract agreement under Cooperative Agreement No. DE-FC26-01NT41181 between DOE and CONSOL Energy, Inc. The scope of supply for Alstom Power, Inc included the design and supply of a Ljungstrom® Air Preheater for installation on a pilot stream installed on an eastern bituminous coal-fired boiler at Allegheny Power, Mitchell Station, Courtney, Pa. The overall purpose of the pilot system was to study technology for multi-pollutant emission control. As a major component, the function of the Ljungstrom® air preheater was to reduce the boiler flue gas temperature to the desired levels prior to entry into the pilot ESP. The preheated air from the air heater was not utilized in the pilot stream, and was discharged into the gas outlet ducting from the main boiler. The scope of this report will cover the design of the air heater, evaluation of Ljungstrom® air heater operating test data provided to Alstom Power, Inc by CONSOL Energy, and the results of the testing conducted on the element installed in the unit.

Section 2: Ljungstrom® Air Preheater Equipment Description and Design Criteria:

The air heater provided on this contract was an Alstom Power, Inc., Air Preheater Co. Size 7-VIK-72 unit including two layers of heat transfer surface with a combined depth of 72 inches. The baskets were configured for optimum cleaning of the heat transfer element by either on-line cold end compressed air sootblowing or off-line hot and cold end water washing. The element in the cold end baskets was coated with a proprietary porcelain enameled surface to facilitate cleaning and as protection against potential cold end corrosion. The element in the hot end layer was made from commercial quality steel but was not coated with enamel. In addition to the initial set of baskets installed in the air heater, three extra pairs of baskets (hot and cold end) were provided for use during the planned long term operating campaigns of the pilot plant. All controls for the air heater operation within the pilot plant system were designed and supplied by others. The attached CONSOL Energy drawings DF-13301-1, rev F, and DF-13301-2, rev F show the location of the air heater in the pilot system, plus define the maximum and minimum design operating conditions for the air heater. A magnesium hydroxide injection system, provided by others, was installed in the gas inlet ductwork upstream of the air heater. The purpose of this injection system was to reduce the SO_3/H_2SO_4 concentration in the gas stream at the air heater inlet to a level that the potential for uncontrollable fouling or corrosion attack in the cold end of the air heater was reduced.

Section 3: Test Program Support Supplied by Alstom Power, Inc. Air Preheater Co.:

The following Engineering services were provided during the project cycle:

a. Design of the Size 1-7-VIK-72” pilot Ljungstrom® air heater for installation on the pilot stream.
b. Participation, as requested, with CONSOL Energy Inc in design evaluation, performance estimation, and system design options regarding the pilot plant design and test program as they applied to the pilot air heater.
c. Participation in an air heater inspection program that was executed during the pilot plant testing program. Performance evaluations were completed based on the air heater operating data provided to Alstom by CONSOL Energy Inc. Alstom’s efforts were focused at evaluating the impacts on the pilot air heater operation due to the low gas outlet temperatures in conjunction with the flue gas composition entering the air heater. The major areas of focus were air heater performance, corrosion, fouling, and cleaning requirements.
d. Submittal of a final test report at the completion of the test program.

Section 4: Heat Transfer Element and Deposit Evaluation:

Two pairs of Ljungstrom® air preheater baskets (each pair consisting of one hot end and one cold end basket) were removed from the pilot air heater during the test program. The first pair was removed after the initial exploratory testing on the pilot plant was completed. Since the air heater had been subjected to a wide range of operating conditions during this period, the evaluation of these baskets was limited to a visual examination. Very little deposit was noted on either basket, and the deposit present was dry. No further analysis was done on the first pair of baskets. The second pair of baskets was installed in the air heater during the period of 8/04-12/04. During this time period, the pilot plant was operated for several test periods of varying duration. Except for 75 hours during the final test period, sootblowing was scheduled at 8 hour operating intervals. The sootblowing operations were suspended during the 75 hour operating period to observe the change in gas side pressure drop. Sootblowing was also scheduled prior to the air heater being shut down at the end of each test period. In order to preserve the nature of the deposit on the element, the normal procedure of sootblowing the baskets prior to shut down was not done at the end of the last operating cycle. The baskets were removed from the unit, wrapped in plastic, and returned to the Laboratory facilities at Alstom Power, Inc., Air Preheater Co for analysis. These baskets were dis-assembled, examined in detail, and the deposits analyzed. The results of this analysis are presented and discussed below.

Visual examination of the baskets and deposits:

A. The hot end basket deposits were randomly located in the depth of the basket. These deposits tended to block the air/gas flow channels. Figure 1 shows randomly located deposits in the hot end and figure 2 shows a group of deposits located on a sheet of element. Figure 3 shows a close-up view of a typical hot end deposit. It reveals the debris and fly ash found within the flow channel of the element.

B. The cold end basket deposits were fairly uniform over the entire sheet, including a band of heavier deposit 6” to 8” up from the gas outlet end of the basket. Figure 4 shows the deposit on a typical sheet in the basket. Figure 5 shows the heavier deposit at the exit end of the cold end basket.

After water washing, the clean sheets were examined. The hot end basket sheets showed light surface rust over 80% of each sheet. The remaining 20% of each sheet was more heavily rusted; these areas of rust had been covered with deposit. There was no evidence of erosion. The sheets from the cold end basket showed glossy enamel coating, indicating that erosion was not on going during operation.

Deposit Weight:

10 sheets from the hot end basket and 10 sheets from the cold end basket were individually weighed with deposits, water washed, dried and re-weighed in a clean condition. The results are reported Table 1 below.

Table 1:

Analysis of Test Baskets from the Operating Period of 8/04 through 12/04

Hot End Sheets	Weight w/ deposit	Weight Cleaned	Deposit Weight	**Cold End** Sheets	Weight w/ deposit	Weight Cleaned	Deposit Weight
Sheet 1	1689	1599	90	Sheet 1	1511	1494	17
Sheet 2	1701	1579	122	Sheet 2	1805	1793	12
Sheet 3	1674	1603	71	Sheet 3	1705	1687	18
Sheet 4	1811	1739	72	Sheet 4	1605	1579	26
Sheet 5	1753	1675	78	Sheet 5	1649	1628	21
Sheet 6	1730	1635	95	Sheet 6	1537	1513	24
Sheet 7	1767	1641	126	Sheet 7	1483	1457	26
Sheet 8	1708	1620	88	Sheet 8	1595	1574	21
Sheet 9	1662	1579	83	Sheet 9	1631	1610	21
Sheet 10	1579	1521	58	Sheet 10	1750	1729	21
Average			88.3	Average			20.7
Std Dev.			21.66	Std Dev.			4.27

Note: All weights reported in grams.

Hot End Basket Element Thickness:

After washing, the thickness of a hot end sheet was measured along one edge. The results are shown in Table 2 below:

Table 2:

Location	Thickness	Location	Thickness	Location	Thickness
Hot Edge	0.024”	17.5”	0.024”	35”	0.024”
3.5”	0.024”	21”	0.024”	38.5”	0.024”
7”	0.024”	24.5”	0.024”	Cold Edge	0.024”
10.5”	0.024”	28”	0.024”		
14”	0.025”	31.5”	0.024”		

The above analysis indicates that the thickness of the hot end sheet was within the standard tolerance of a new element sheet installed in the hot end basket. There was no evidence that rapid corrosion occurred on the hot end element during the operating cycle when the basket was installed.

Deposit Analysis from Hot and Cold End Baskets:

Deposit samples were taken from both the hot and cold basket sheets for analysis. A deposit sample from the cold end of the cold end basket was scraped from the sheets. From the hot end basket, the “primary deposit” was collected by turning the sheet on edge and tapping the sheet. This deposit was loose, free flowing and easily fell from the sheet. Following the collection of the “primary deposit”, it was observed that localized deposits still remained on the sheet. These deposits, identified as a “secondary deposit” adhered to the element surface to the extent that they would not fall from the sheet when it was turned on its side. This deposit was scraped from the hot end basket after the “primary deposit” had been collected.

The sample collected from the cold end basket was subjected to elevated temperatures to determine if sulfuric acid was present. The heating test temperatures were selected to remove water (220°F) and sulfuric acid (650°F), if present, from the deposit. The test results for the two temperature levels maintained are shown in Table 3 below:

Table 3:

Time & Temperature	Original Weight	Treated Weight	Weight Lost	Percent Lost
220°F – 4 hours	8.3889g	7.9132g	0.4757g	5.7%
650°F – 4 hours	9.0808g	8.2985g	0.7823g	8.6%

Water and sulfuric acid can be present in the deposit both as free liquids, and contained in surface compounds. It is known that calcium oxide, magnesium oxide and iron oxide can form sulfated compounds, and these compounds will absorb water to become hydrated compounds. For example, CaSO4 can become hydrated to form CaSO4•1/2 H2O (Plaster of Paris) or CaSO4•2 H2O (gypsum). With regard to these calcium compounds, it is known that dehydration will take place in dry air at 212°F and 104°F respectively. The details regarding the dehydration of the other compounds are not known. However, it has been assumed that heating to 220°F will cause the complete evaporation of all free water and any waters of hydration that may be present in a XSO4•n H2O compound. As stated previously, sulfuric acid can be present in a deposit as free acid and also as an acid compound. For example, it is known that CaSO4 will form sulfuric acid compounds of the form CaSO4•n H2SO4, where n=1/2, 1, 2 or 3. Literature data indicates that the acid compounds are not affected by heating at temperatures below 482°F. However, the boiling point of concentrated sulfuric acid is approximately 639°F, and it was assumed that heating the deposits beyond this temperature will liberate the acid regardless of its form.

Based on the results of the heating tests, it can be concluded that the cold end deposit contained 2.9% sulfuric acid by weight. Due to the potential for the presence of acidic compounds, this amount represents the summation of both the free acid and the acid contained in these compounds.

In addition to the elevated temperature tests noted above, the three samples were individually analyzed for the elemental composition. Listed below in Table 4 are the results of this analysis for the sample locations noted.

Table 4:

PPL Sample No.	5-2043-A	5-2044-A	5-2045-A
Sample I.D.	deposit from cold end of cold end basket	Primary Deposit Hot Basket	Secondary Deposit Hot Basket
Elemental Composition as % of the Oxide			
% SiO2	33.4	33.9	35.3
% Al2O3	17.1	16.6	17.6
% Fe2O3	19.8	27.2	25.6
% CaO	3.6	3.4	3.2
% MgO	2.5	1.5	1.7
% Na2O	0.8	0.6	0.5
% K2O	2.1	1.9	1.9
% TiO2	1.2	1.3	1.2
% P2O5	0.2	0.2	0.1
% SO3	19.3	13.5	12.8
% Total	100.0	100.0	100.0

The chemical analysis of the cold end sample indicated that the deposit was primarily coal ash plus iron and sulfur reaction products with only a small amount of free sulfuric acid present. The solution pH of these samples was in the pH 2 to 3 range. A solution pH of 1 or less would be measured if free sulfuric acid was present in the sample. The test results indicated little or no free sulfuric acid was present. This was possible based on the potential for the formation of acid compounds based on the elemental oxides found in the samples. The presence of large amounts of free acid in the deposit would result in a wet,

sticky deposit on the element. However, the deposit was not wet and sticky, which was another indication that there was little free sulfuric acid present.

Further examination of the cold end basket sheets revealed that the deposits were mostly at the cold end of the sheet. This is also the location where sulfuric acid condensation would occur. The deposit analysis indicated that the deposit was predominately fly ash and iron sulfate. However, the enamel prevents corrosion of the steel under the coating, which leads to the question, what was the source of the iron? It is probable that the iron was coming from rust particles (iron oxides) that were formed upstream of the air heater cold end baskets, carried into the cold end baskets by the gas flow, captured on condensed acid and flyash deposits, and reacted to form iron sulfate. It is important to note that this process reduced the amount of free sulfuric acid existing in the deposit, and therefore would make the deposit easier to remove from the surface.

The analysis of the “primary” and “secondary” deposits removed from the hot end basket showed that they were similar in chemical composition, and contained significant levels of iron. The reason that the “primary” deposit was loose and free flowing while the “secondary” deposit was more tightly attached to the element sheet is unknown. It is postulated that some corrosion occurred upstream of the air heater. These corrosion products traveled along the ductwork to the air heater, and became part of the deposit found on the hot end basket. The “secondary deposits” on the hot end sheets were randomly located in the depth of the element. These deposits included clumps of flakes that were captured in the element channels, blocked the channels, and then had fly ash build-up behind the blockages. The apparent random locations indicated that the deposits were mechanical blockages by relatively large flakes in the element channels. The deposit analysis indicated that the flakes were iron-based with fly ash. Large rust or iron sulfate flakes would have the strength to become lodged in the element channels and cause these types of deposits. The term “iron sulfate” is used in this report and while the elemental analysis did not determine iron sulfate specifically, it did indicate that iron/sulfur compounds were present in the deposits taken from both the hot and cold end baskets. The source of the flakes was probably up-stream of the air heater gas inlet. The fly ash that was captured behind these blockages was the reason for the larger deposit weights found on the hot end element as compared to the cold end element. It was possible for the samples taken from the hot basket to contain the higher level of iron-based material because the hot end element has a narrower channel opening than the cold end element. Therefore, the particles that passed through the hot end basket were less likely to be captured in the cold end layer.

Overall, the sheets in the air heater test baskets were in good condition. After water washing in the lab, the enameled sheets were glossy, indicating that there had been no corrosive or erosive attack on the sheets. The carbon steel sheets developed light rust after washing but most sheet areas were basically not attacked. There was light corrosion in some areas of the sheets (at the heavy rust sites) and many of these areas were associated with the hot end deposit locations, indicating that there was some local corrosion under the deposits of the hot end. In general, thickness measurements of a hot end element sheet confirmed that there was very little or no wide-scale corrosion of the hot end element sheets. The cold end sheets would not be attacked due to the enamel coating plus there was not enough operating time or acid present during the test to corrode the enamel surface.

Sootblowing Test:

One enameled sheet from the cold end basket was placed in a sootblowing test stand and the sheet was sootblown at 200 psia at a distance of 12” from a stationary ½” diameter nozzle. The sheet was weighed before the blow (1389g), after the blow (1381g), and after water washing (1373g). Figure 6 shows the entire sheet before blowing. Figure 7 shows the cold end of the sheet before blowing. Figure 8 shows the cold end of the sheet after blowing. Figure 9 shows the hot end of the sheet after blowing. Comparing Figure 7 and Figure 8, it can be seen that there was significant cleaning at the cold end of the enameled element sheet during the sootblowing test. Comparing Figures 6 and 9 shows that there was also significant cleaning at the hot end of the enameled sheet during the sootblowing test. The sootblowing test stand was configured such that the test sheet was imbedded in a stack of the element with the same geometry. The nozzle was aligned with the centerline of a channel consisting of the test sheet on one side and a sheet from the element stack on the other side. Therefore, the sootblower jet could pass over both sides of the test sheet. Since the jet is diverging as it approaches the element, it passed through the target channel, plus through adjacent channels on the test sheet that were located on either side of the target channel. There was a total of 16 grams of deposit on the sheet and 8 grams were removed during the

sootblowing test. The alignment of the stationary nozzle on the center of one channel, plus the fact that the diverging jet removed deposit material from the adjacent channels on both sides of the target channel makes a direct calculation of the percentage of the deposit that was removed difficult. Within a full-scale Ljungstrom® air heater, each channel of the element is subjected to in-line flow from the nozzle, plus the peripheral flow from the nozzle as the element approaches and leaves the nozzle location due to rotation of the air heater rotor. For analysis purposes, it was assumed that the test cleaned both sides of the sheet for the target channel, plus both sides of the sheet in the channels on either side of the target channel, and that the 8 grams of material were removed from the target channel. On this basis, the test indicates that a total of 24 g could be removed. Since, this is greater than the total amount of deposit on the sheet and considering the photographic evidence, the cleaning efficiency was predicted to be in excess of 90%.

Section 5: Operating Performance Summary:

Due to the wide range of operating conditions that existed on the original baskets installed in the air heater, the operating performance analysis was based on the performance conditions that existed during the period of August 2004 through December, 2004. Table 5 below summarizes the predicted vs. measured flow rates and temperatures for the conditions noted. All test data was provided by CONSOL Energy, and was analyzed with an Alstom Power, Inc. proprietary performance code.

Table 5: Comparison of Measured and Calculated Air Heater Operating Data

Test Start Date	Gas inlet flow,#/hr.			Gas Outlet Temperature, °F			Air Outlet Temperature, °F		
Date	Measured	Calculated	Variance,	Measured	Calculated	Variance,	Measured	Calculated	Variance,
8/23/04	17,430	17,788	(358)	293	315	(22)	525	604	-79
8/30/04	17,339	17,793	(454)	267	291	(24)	510	594	-84
9/7/04	17,405	17,891	(486)	242	262	(20)	493	583	-90
12/3/04	15,171	16,386	(1,215)	294	393	(99)	515	599	-84
12/7/04	16,172	16,423	(251)	233	272	(39)	499	580	-81
12/14/04	16,844	16,307	537	239	282	(43)	524	585	-61
12/22/04	17,017	14,228	2,789	242	299	(57)	506	600	-94

Note: Variance=Measured-Calculated

Discussion of Operating Performance Data:

The raw data pertaining to the Ljungstrom® air preheater operation during the period from late August 2004 through the end of December 2004 came from seven data files provided by CONSOL Energy Inc. Each file covered the air heater operating data for a period ranging from a couple of days up to a week.

After reviewing the raw data files, it was decided that some data filtering was required in order to focus on the periods of steady state operation. Transient data associated with start-up, shutdown, or other unsteady state operation was filtered from the analysis. Data was removed from the analysis if the gas inlet temperature was below 600 °F, if the gas out temperature was outside of the 200-350 °F range, or if the cold end pressure difference was outside the 0.4-0.6 in. WC range. Some of the remaining data was collected when the magnesium hydroxide slurry injection system was off, and some was obtained while it was in operation.

A review of the data indicated that the gas inlet flow measurement appeared to be truncated above a flow rate of about 17,500 pounds per hour, and this condition was consistent for all data samples. It is believed that the measured gas inlet flow was therefore biased, and that the average reported gas inlet flow rate was lower than the true value by some unknown amount. For this reason, the gas outlet flow (which

showed greater stability) was used in analyzing the air heater operating data. Therefore, gas pressure losses were correlated to gas out flow rather than gas in flow or an average of the two because of the apparent bias in the gas inlet flow values. There was no air out flow measurement reported during the test periods under review, so it was not possible to determine from the data the magnitude of the gas to air leakage.

For purposes of uniformity in data evaluation, the following procedure was used to analyze the raw data:

1. Filter the data from each file to remove data taken while the air heater was not at steady state conditions.
2. Average the remaining data within each file to obtain inputs for the air heater performance code.
3. Using the averaged data from a given file, calculate the air heater performance for those inputs. This means that the output from a single code run was compared to the averaged data from the selected time period.
4. Calculate and graph the Euler (Eu) number from both the measured and calculated gas pressure drops.

The Euler number is a dimensionless number that expresses the ratio of the pressure drop of a flowing fluid to its velocity pressure. It is a measure of the flow resistance of the channel in which the fluid is flowing. In this case, the fluid was the gas flowing through the pilot air heater, and the channels were the spaces between the heat transfer element sheets. While the actual pressure drop is very sensitive to the gas flow rate, the Euler number (Eu) is much less dependent on the flow rate. The Euler numbers (both measured and determined from the performance code output) were calculated based on the gas outlet flow because the raw data from this location appeared to be more stable and complete. Thus, the velocity pressure of the gas was computed using the gas outlet flow and the gas density at the average gas temperature.

Analysis of the Ljungstrom® air heater operating data:

Figure 10 shows the measured and calculated pressure drops (DP's) on the gas side of the air heater. For the August-September data sets, the measured DP's, on average, exceeded the calculated DP's by roughly 13%, and the calculated DP's fell within the range of measured DP's, albeit at the low end of that range, for the first two data sets. The amount by which the measured DP's exceeded the calculated values grew steadily larger with time. The first data set (8/23-8/26) showed the measured DP's to be higher by 10%. In the second set (8/30-9/3), they were higher by 13%, and in the third set (9/7-9/9), they were higher by 16%. However, the data from the December 2004 operating period indicated a different condition existed. In December, the measured DP's were consistently higher than the calculated DP's by about 45%. This ratio held constant over all four sets of data taken in December, and showed no increase with time.

Figure 11 shows a graph of the Eu number over the duration of the full test period of 8/04 through 12/04. The Eu trend is essentially the same as the pressure drop trend. Figures 12 and 13 show the same data displayed in Fig. 11, except that the data is broken into two groups to expand the horizontal axis. Fig. 12 covers the period from 8/21/04 through 9/10/04, and Fig. 13 covers the period from 12/1/04 through 12/26/04.

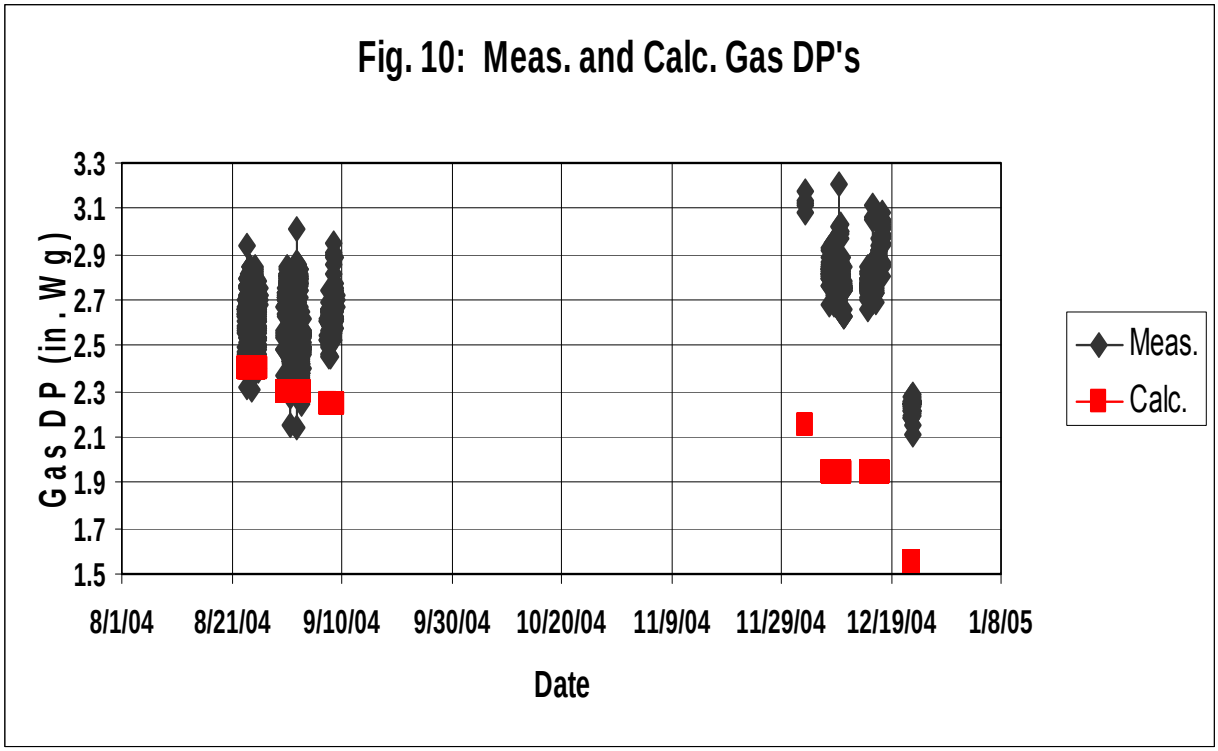


Fig. 10: Meas. and Calc. Gas DP's
Gas DP (in. Wg)
3.3
3.1
2.9
2.7
2.5
2.3
2.1
1.9
1.7
1.5
8/1/04
8/21/04
9/10/04
9/30/04
10/20/04
11/9/04
11/29/04
12/19/04
1/8/05
Date
Meas.
Calc.

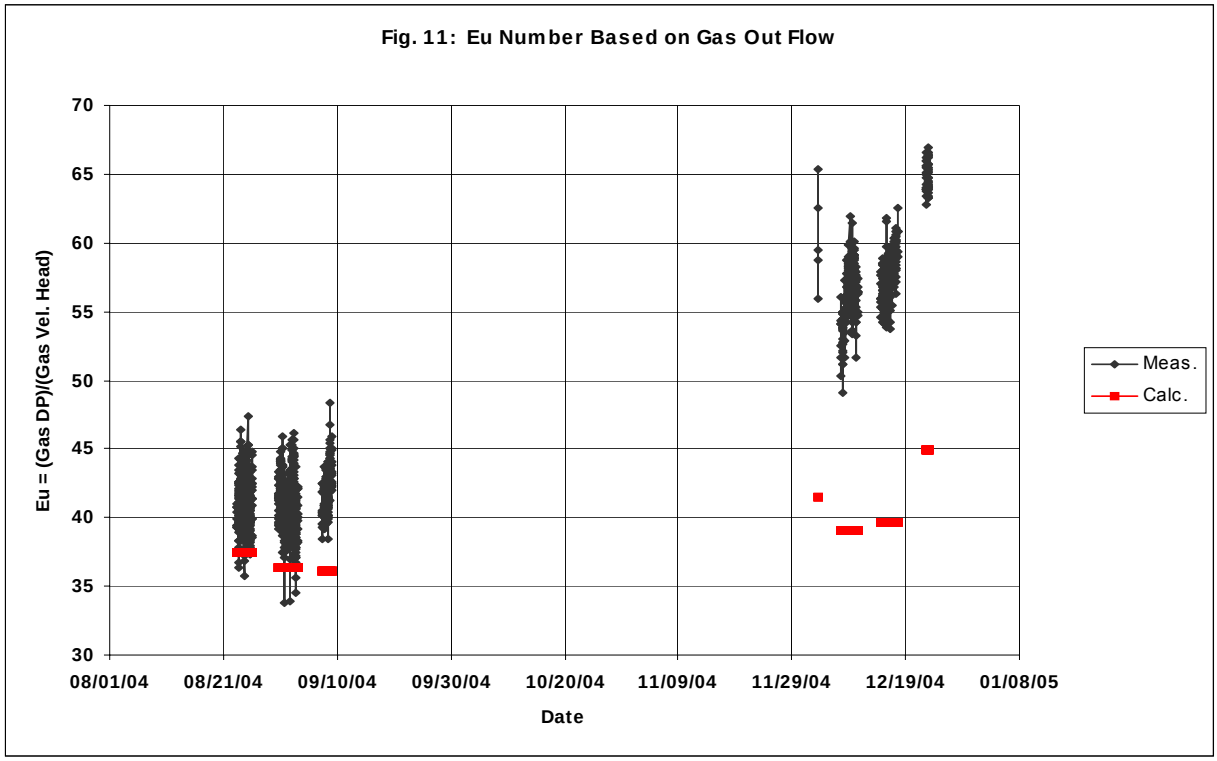


Fig. 11: Eu Number Based on Gas Out Flow
Eu = (Gas DP)/(Gas Vel. Head)
70
65
60
55
50
45
40
35
30
08/01/04
08/21/04
09/10/04
09/30/04
10/20/04
11/09/04
11/29/04
12/19/04
01/08/05
Date
Meas.
Calc.

Fig. 12: Eu Number Based on Gas Out Flow

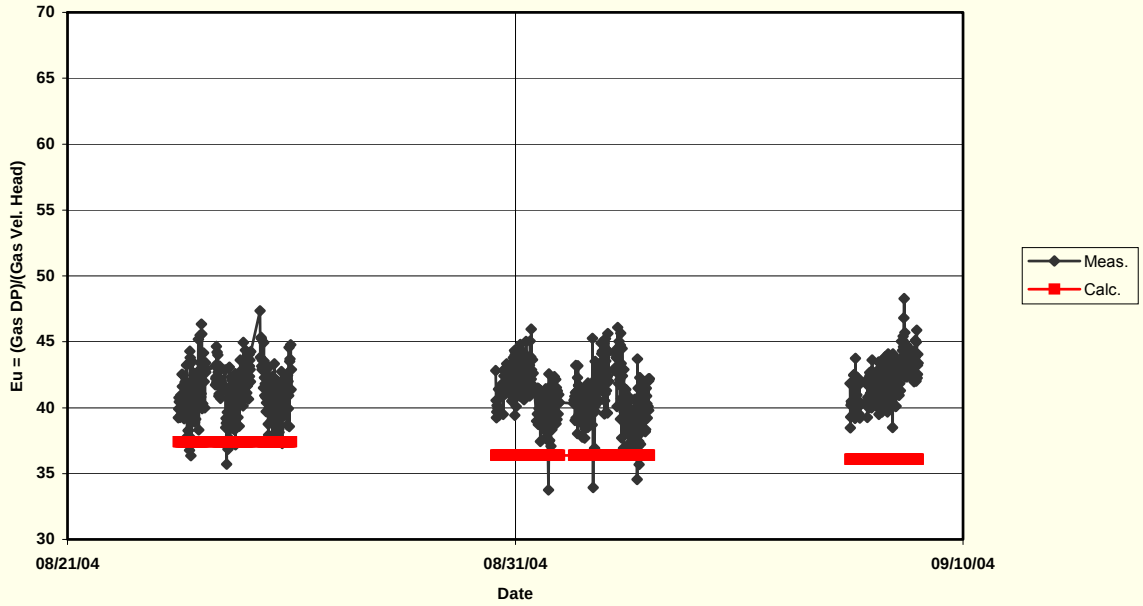
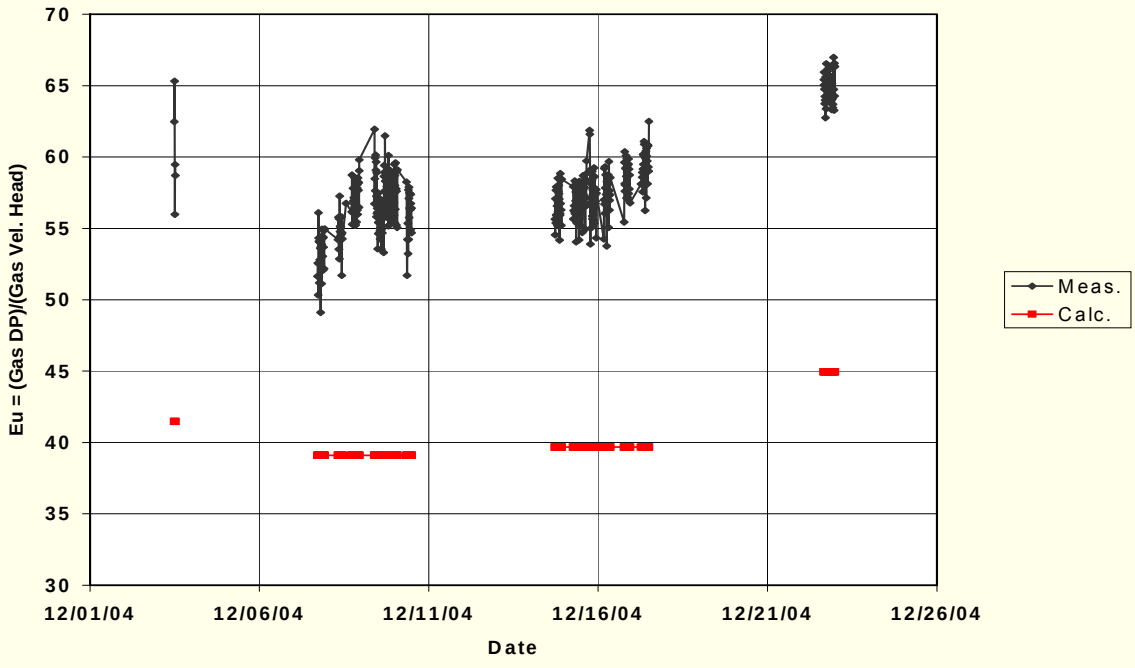


Fig. 13: Eu Number Based on Gas Out Flow



The Ljungstrom® air heater performance code was setup so that the air inlet and gas inlet temperatures, plus the gas outlet and air inlet flow rates, matched the measured data, i.e., they were inputs to the performance code. The measured gas outlet static pressure plus the cold end differential pressure were also inputs to the performance code. Using these inputs, the theoretical gas to air leakage was calculated. Utilizing these leakage values at the hot and cold ends of the air heater permitted the calculation of the two

unknown flow rates, i.e., the gas inlet flow and the air outlet flow. Although the air out flow was not measured during this test period, the gas inlet flow was measured, so it was possible to compare the measured versus calculated values for the gas inlet flow. It was also possible to compare the measured versus calculated values for the air outlet and gas outlet temperatures. These measured vs. calculated comparisons are shown in Table 5 above.

Table 5 shows that the August/September, 2004 field data compared rather consistently to the calculated values. For these three data sets, the gas inlet flow rates differ by 300-500 pounds per hour, the gas outlet temperatures varied by 20-24 °F, and the air outlet temperatures differed by 80-90°F. However, the data from December 3, 2004 shows a large difference (99°F) between the calculated and measured values for gas outlet temperature and gas inlet flow. A probable explanation for this variance is the short duration (less than 1 hour) of filtered data from this test run. A review of the original data showed that the air heater might not have reached steady state conditions when this data was taken.

The data in Table 5 for the December 7th and December 14th indicated gas flow rate differences of several hundred pounds per hour. This is in line with the first three tests. In addition, the air outlet temperature differences for these two tests were consistent with the first three tests. However, the gas outlet temperature differences were nearly twice as large as the August/September, 2004 test period data. It is not clear what the reason for this is, nor is it understood why the last test (December 22, 2004) had relatively large differences in all three measured vs. calculated quantities.

Section 6: Summary Conclusions and Recommendations:

CONCLUSIONS:

1.The hot end basket deposits on the element initiated from particle flakes being mechanically wedged in the tighter hot end element channels. This was followed by a build-up of fly ash behind the blockage.

2.The cold end basket deposits on the element were primarily fly ash and other particles initially captured in sulfuric acid on the surface of the cold end element. This is typical cold end fouling for an air heater. As discussed above, it is probable that the acid reacted with components in the fly ash to form sulfates and therefore reduce the amount of free acid in the deposit. Lower concentrations of free acid in a deposit tend to make the deposit easier to remove from the element with conventional sootblowing technology. In addition, the conditioning of the flue gas by the magnesium hydroxide to reduce the inlet SO_3/H2SO_4 concentration would also lower the concentration of free acid in the deposit.

3. There was little free sulfuric acid found in the deposits. The presence of little or no free sulfuric acid reduced the tendency of a deposit to form that was difficult to remove during the sootblowing cycle. In general, as the concentration of free sulfuric acid in a deposit increases, the ability to remove it with conventional sootblowing technology decreases. The soot-blowing test indicated that a significant amount of the deposit on the enameled cold end sheet could be removed with a soot blowing process. However, the deposit present on the sheets was the result of a combination of operating periods. For the initial portion of the test cycle, sootblowing was scheduled at 8-hour intervals, plus before shutdown at the end of each operating cycle. Near the end of the test cycle in December 2004, the scheduled 8-hour blowing interval was suspended in order to observe the change in gas side pressure drop without sootblowing. The test results, plus the physical examination of the deposit indicated that a significant portion of the deposit was removed from the element. The sootblowing test also indicated that a residual deposit existed on the element after the blowing cycle and this deposit would likely exist during normal operation. However, the duration of testing did not provide enough data to be able to predict the characteristics of a deposit over an extended period of plant operation, or predict the frequency that off-line water washing would be required for element cleaning.

4.The amount by which the measured gas side pressure drop exceeded the calculated pressure drop grew steadily larger with time. In the 8/23/04-8/26/04, the measured gas side pressure drop was higher by 10%. In the time period from 8/30-9/03/04, the measured value was higher by 13%, and in the time period of 9/7-9/9/04, the value was higher by 16%. However, the December 2004 data indicated a much different result. For the 4 sets of data taken in this time period, the measured gas side pressure drop was higher

than the calculated value by an average of 45%. This ratio was evident in the 4 sets of operating data in December, and showed no increase over time. It is probable that the deposits found in the hot end baskets contributed to the pressure drop increase, but the pressure drop split between the hot and cold end layers could not be determined. It is difficult to make quantitative conclusions about this data due to the short duration of the operating cycles, plus the gas outlet temperatures was also changed during these time periods. However, the data is encouraging and indicates that rapid fouling of the cold end element did not occur during this time period.

5. Water washing of the air heater was not conducted at any time during the entire test period. The unit was equipped with both hot and cold end water washing systems in the event a rapid accumulation of a deposit that could not be controlled by cold end soot blowing developed within the air heater. However, all Ljungstrom® Air Preheaters installed on reduced cold end temperature applications should be equipped with hot and cold end water washing systems.

6. The data analysis included in this report was based on short periods of operation at the reduced gas outlet temperatures. Although the results do not indicate major corrosive activity on the element sheets, and the majority of the deposit could be removed with sootblowing, long-term operating results are difficult to predict from this data. The use of magnesium hydroxide injection appears to have conditioned the flue gas prior to the entry into the air heater such that rapid cold end fouling and/or corrosion of the element did not occur. It is the position of Alstom Power, Inc., Air Preheater Co. that the test results from the 8/04 through 12/04 time period were favorable enough to warrant further validation testing. There was no evidence in the data that was examined to indicate that an uncontrollable build up in pressure drop was on going or that large-scale cold end corrosion was present in the air heater. Therefore, it is recommended that additional testing with continuous, steady state operation (24 hr/day) with the Ljungstrom® Air Preheater operating at the desired reduced gas outlet temperature be conducted in order to further validate the results.

Section 7: Attachments:

Figure 1.

Figure 2

Figure 3.

Figure 4.

Figure 5.

Figure 6.

Figure 7.

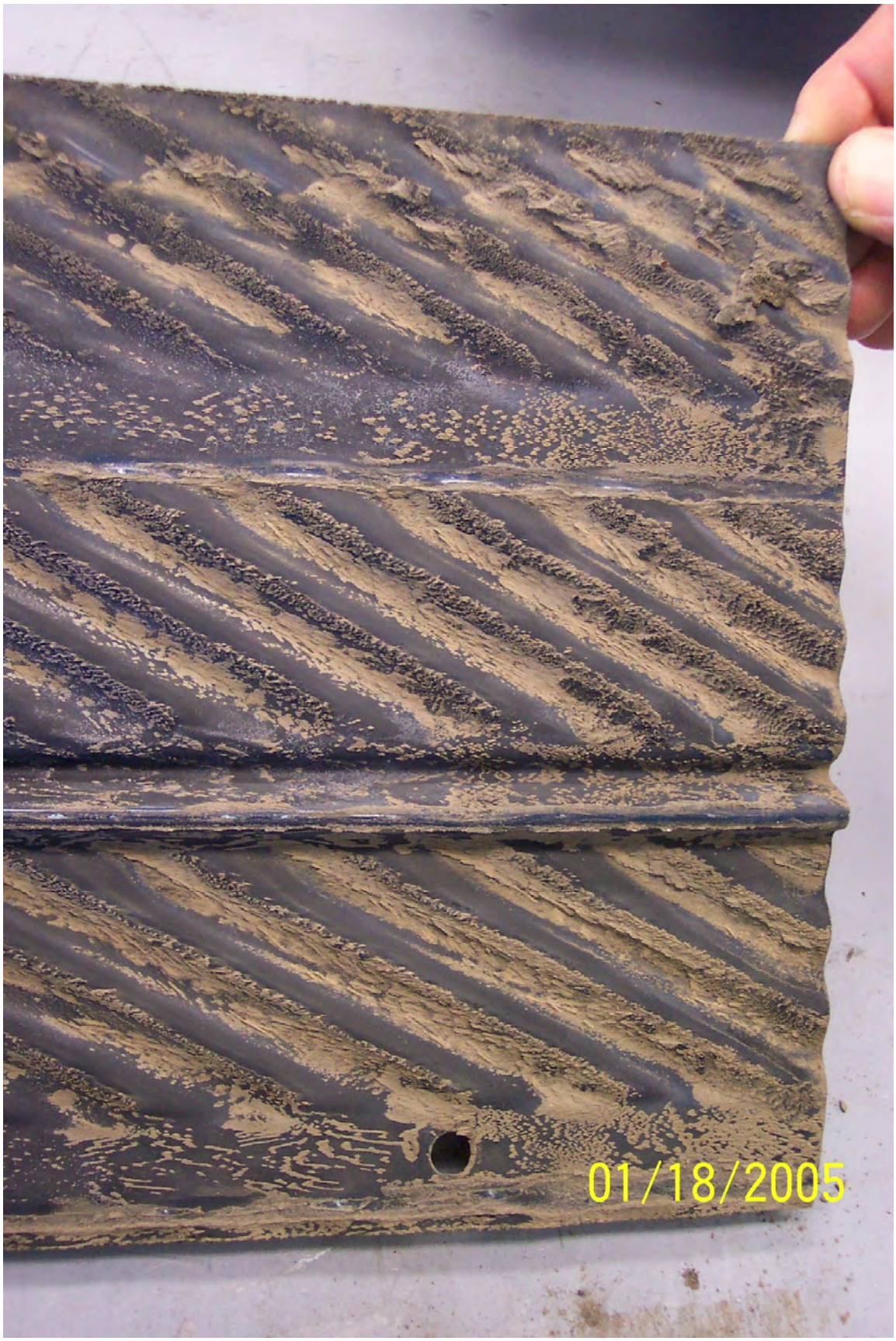


Figure 8.

Figure 9.

Appendix E.

"Control of Mercury Emissions by Absorption on Fly Ash – Final Experimental Results of the CONSOL/Allegheny Pilot Plant Program" to be presented at the International Conference on Air Quality V, Mercury, Trace Elements, and Particulate Matter, Arlington, VA, September 19-21, 2005.

CONTROL OF MERCURY EMISSIONS BY ABSORPTION ON FLYASH – EXPERIMENTAL RESULTS OF THE CONSOL/ALLEGHENY PILOT PLANT PROGRAM

R. A. Winschel, M. L. Fenger - CONSOL Energy Inc.
K. H. Payette - Allegheny Energy Supply Co., LLC
L. A. Brickett – National Energy Technology Laboratory, US DOE

DOE/NETL Mercury Control Technology R&D Program Review Meeting,
Pittsburgh, July 14, 2005

CONCEPT

- **Absorb Hg on flyash by cooling flue gas to 200-210 °F with air heater and water spray**
- **Collect flyash with ESP to remove Hg**
- **Protect against acid corrosion and air heater fouling by introducing $Mg(OH)_2$ into flue gas upstream of the air heater**

POTENTIAL BENEFITS OF TECHNOLOGY

- 70-90% Hg removal
- Projected cost ($/lb Hg) an order of magnitude lower than carbon injection by utilizing unburned carbon
- Suitable for retrofitted or new plants
- Potentially suitable for the full range of coal types
- Effective SO_3 reduction at air heater inlet
  - ▶Visible plume mitigation
  - ▶TRI reduction
  - ▶SCR/SNCR benefits
  - ▶Secondary fine particulate reduction
- Potential to improve heat rate by 2%
  - ▶2% reduction in NO_x, SO_2, CO, particulate and CO_2
  - ▶~ $600,000/y fuel cost savings for 600 MW plant

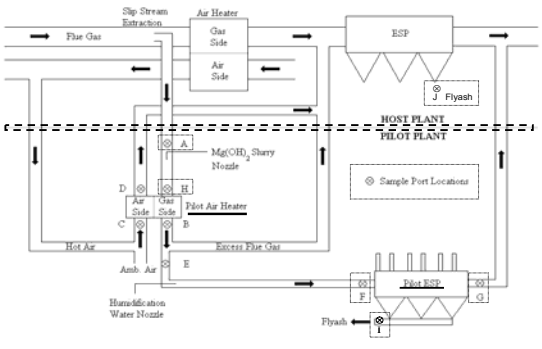
HOST PLANT

Allegheny Energy Mitchell Station

- **Courtney, PA**
- **288 MW Unit 3, corner fired**
- **In service 1963**
- **Thiosorbic lime wet FGD, ESP, no SCR**
- **Fired with eastern bituminous coal**
  S 3.0 - 4.8% Ash 9.3 – 15%
  Cl 0.05 - 0.09% Hg 0.09 - 0.13 mg/kg

*Analyses on dry basis, except Hg as determined

PILOT PLANT PROCESS SCHEMATIC



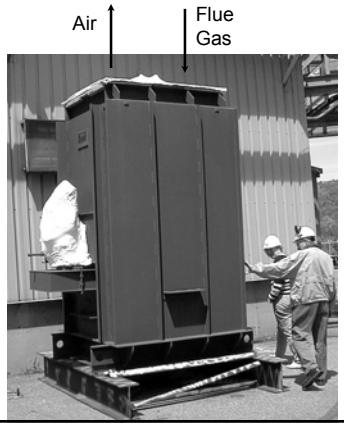
PILOT PLANT OPERATION

Test Condition	Total Operating Hours	Continuous Operating Hours-Max.	Mg(OH)2 Injection	ESP Flue Gas Temperature - °F
Baseline	1198	332	NO	300
Short Term	390	13	YES	230-250
Long Term	393	75	YES	200-210

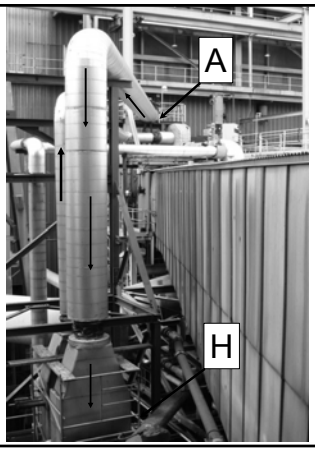
EXPERIMENTAL PLAN
SO_3 CONTROL

- AH flue gas flowrate: 14,500 lb/h (1.5 MWe)
- Mg/SO_3 molar ratio: 4/1 (<3 ppmv AH inlet)
- Gas temperature at AH outlet: 225 - 230 ºF
- Gas sampling: SO_3 at AH
- Coal samples: host plant
- Evaluate air heater fouling: ΔP and dissection of AH baskets
- Monitor corrosion: probe and coupons at ESP
- Sootblowing frequency: 8 hours during Baseline & Short Term, 24 to 75 hours during Long-Term

PILOT AIR HEATER



FLUE GAS $Mg(OH)_2$ INJECTION

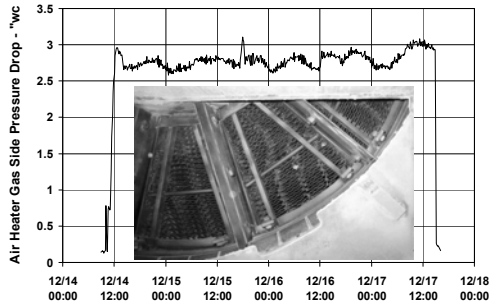


EFFECTIVENESS OF $Mg(OH)_2$ INJECTION FOR SO_3 CONTROL

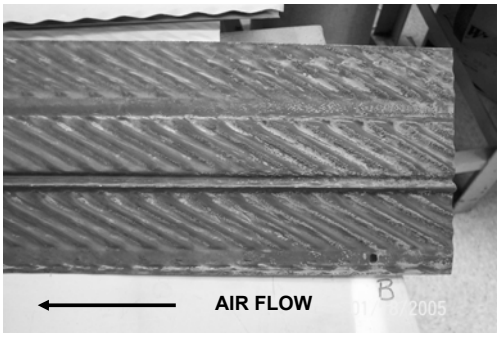
	Average SO_3 Concentration, ppmv *(Acid Dew Point, °F)*		
Mg:SO_3 Mole Ratio (Test Condition)	Before Mg Injection at Location A	After Mg Injection* > Removal % at Location H	Air Heater Gas Out at Location B
None (Baseline)	12.5 *(274)*	-	2.1 *(237)*
2/1 (Short Term)	31.4 *(278)*	6.8 *(256)* > 79%	1.2 *(230)*
4/1 (Short Term)	32.5 *(288)*	1.8 *(236)* > 94%	0.7 *(222)*
4 to 27/1 (Long Term)	14.8 *(276)*	2.2 *(239)* > 84 %	-

*3 ppmv target

AIR HEATER PRESSURE DROP



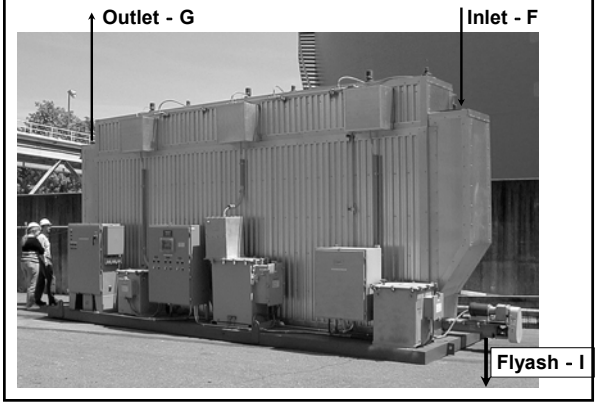
AIR HEATER – CE ELEMENT



EXPERIMENTAL PLAN MERCURY CONTROL

- ESP flue gas flowrate: 3,900 lb/h (100 SCA)
- Mg/SO_3 molar ratio: 4/1 (<3 ppmv AH Inlet)
- Gas temperature at ESP inlet: 200 - 210 °F
- Flue gas cooling: air heater (75 hours cont.) and water spray (4 hours cont.)
- Gas sampling: OH Hg at ESP inlet and outlet
- Flyash & coal samples: pilot ESP and host plant
- Evaluate ESP performance: PM removal >99%
- Evaluate stability: captured Hg on flyash

PILOT ESP

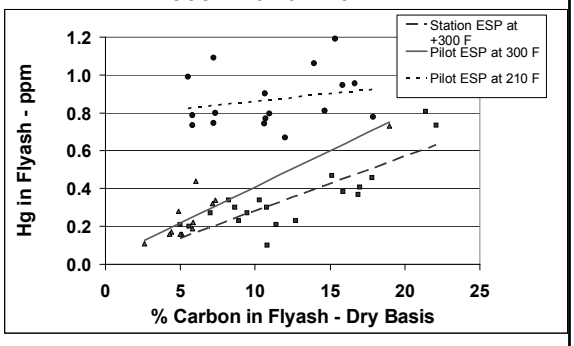


PILOT ESP INSTALLATION

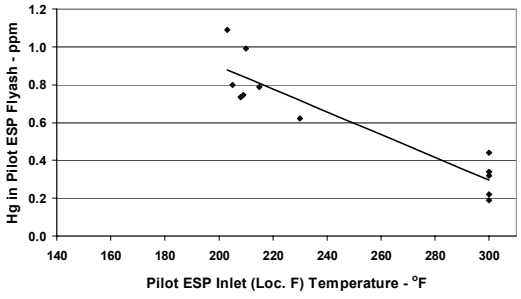
MERCURY CAPTURE BY ESP

Test Condition	ESP Inlet, Location F Temp. - °F	Hg Removal By ESP, Gas Inlet to Outlet Average %	"Carbon Treat Rate" Average lbs Carbon / million scf and acf (Range of Data)	
Baseline	290	26%	41 (41) scf	26 (26) acf
Short-Term	230-250	49%	35 (46-23) scf	23 (31-15) acf
Long-Term	200-210	81%	47(71-23) scf	33 (51-15) acf

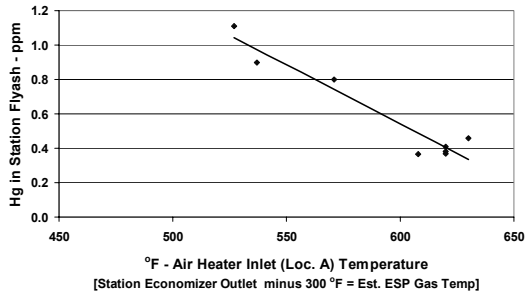
MERCURY vs CARBON IN FLYASH AT 300 °F and 210 °F



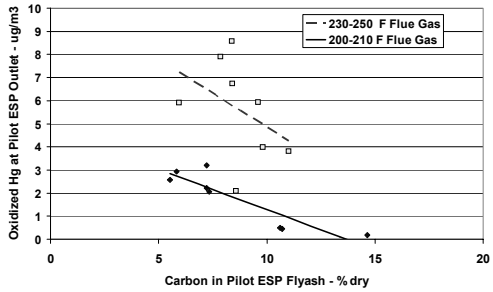
Hg on FLYASH vs TEMPERATURE 5.9-7.2% CARBON – PILOT PLANT



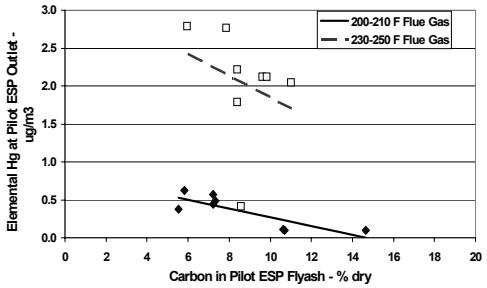
Hg on FLYASH vs TEMPERATURE 16-18% CARBON - HOST PLANT



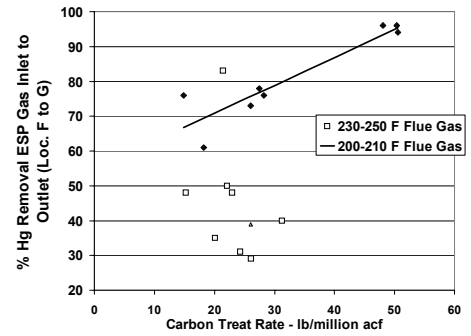
OXIDIZED Hg in FLUE GAS vs CARBON AT LOWER TEMPERATURES



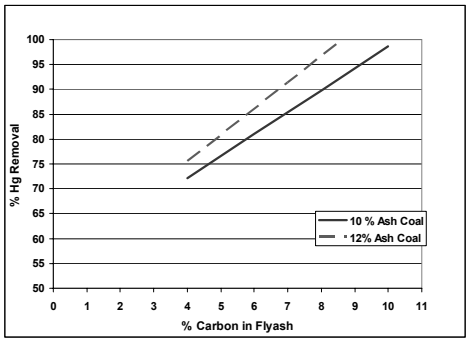
ELEMENTAL Hg in FLUE GAS vs CARBON AT LOWER TEMPERATURES



Hg REMOVAL VS CARBON RATE



Hg REMOVAL vs % UBC with 200 °F FLUE GAS



PRINCIPAL CONCLUSIONS

- Over 90% ESP mercury removal demonstrated with air heater cooling at 200-210 °F (limited WS cooling showed similar results)
- Mercury removal sensitive to temperature, carbon content of flyash and carbon content of the flue gas
- Baseline conditions give about 26% mercury removal
- At 200-210 °F, elemental and oxidized mercury effectively captured by the flyash
- $Mg(OH)_2$ slurry injection is effective for removal of SO_3 and eliminates rapid fouling of the air heater
- Pilot ESP performed satisfactorily at low temperature conditions

ADDITIONAL CONCLUSIONS

- Mercury volatility and leaching tests did not show any stability problems
- No significant corrosion detected at the air heater and on corrosion coupons at the ESP
- Corrosion probe showed reduced acid condensation on corrosion probe during $Mg(OH)_2$ injection

ACKNOWLEDGEMENT

- US DOE, NETL, CA No. DE-FC26-01NT41181 (Lynn Brickett)
- Alstom Power, Inc.
- Environmental Elements Corp.
- Carmeuse NA, Inc.
- J. A. Withum, J. E. Locke and R. M. Statnick

Appendix F

Control of Mercury Emissions By Absorption On Flyash - Final Experimental Results of the CONSOL/Allegheny Pilot Plant Program Presented at the International Conference on Air Quality V, Mercury, Trace Elements, SO_3, and Particulate Matter, 9/19-21/05, Arlington, VA

CONTROL OF MERCURY EMISSIONS BY ABSORPTION ON FLYASH – FINAL EXPERIMENTAL RESULTS OF THE CONSOL/ALLEGHENY PILOT PLANT PROGRAM

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U. S. Dept. of Energy, National Energy Technology Laboratory, P. O. Box 10940, Pittsburgh, PA 15236

Abstract

The Low Temperature Mercury Control, or LTMC, process is a technology developed by CONSOL Energy for controlling mercury emissions from coal-fired power plants. In the LTMC process, mercury emissions are controlled by cooling the exhaust flue gases with an air heater (or water spray) beyond the typical 300 ^{o}F to about 200 – 220 ^{o}F, thereby promoting mercury absorption on the coal fly ash. The fly ash containing the absorbed mercury is then captured in the power plant's existing particulate collection device. An alkaline material, magnesium hydroxide slurry in our tests, is injected to eliminate sulfur trioxide (sulfuric acid) which could otherwise condense at the cool temperature and corrode the power plant's air heater and ductwork.

In addition to controlling mercury emissions, the technology reduces the emissions of sulfur trioxide and could alleviate the visible plume problem sometimes associated with selective catalytic reduction applications. The technology can also allow improved generating efficiency if the cooling is effected by an air heater (rather than by water sprays); this would lead to reduced fuel usage and lower emissions of most pollutants and carbon dioxide.

CONSOL Energy and Allegheny Energy Supply, with support from the U.S. Department of Energy's National Energy Technology Laboratory, constructed and operated a pilot plant using flue gas from a coal-fired power generating station to develop the LTMC technology. Other participants in the development program were Alstom Power Inc., Environmental Elements Corp., and Carmeuse Lime, Inc. The performance of the process toward mercury removal and sulfur trioxide control, the influence of operating conditions, and the certain balance-of-plant impacts were evaluated at a 3640 scfm slip-stream pilot plant located at the Allegheny Energy Supply Mitchell Station in Courtney, PA. The pilot plant extracted flue gas immediately downstream of the Mitchell Station's economizer,

and routed the extracted gas through a magnesium hydroxide slurry injection system, a pilot air heater, a water spray system, and a pilot electrostatic precipitator (ESP), as shown in Figure 1. During tests, samples of flue gas were taken at various locations in the pilot plant, and samples of fly ash were taken to determine the performance of the process. During the testing, the Mitchell Station burned high-sulfur northern Appalachian bituminous coal.

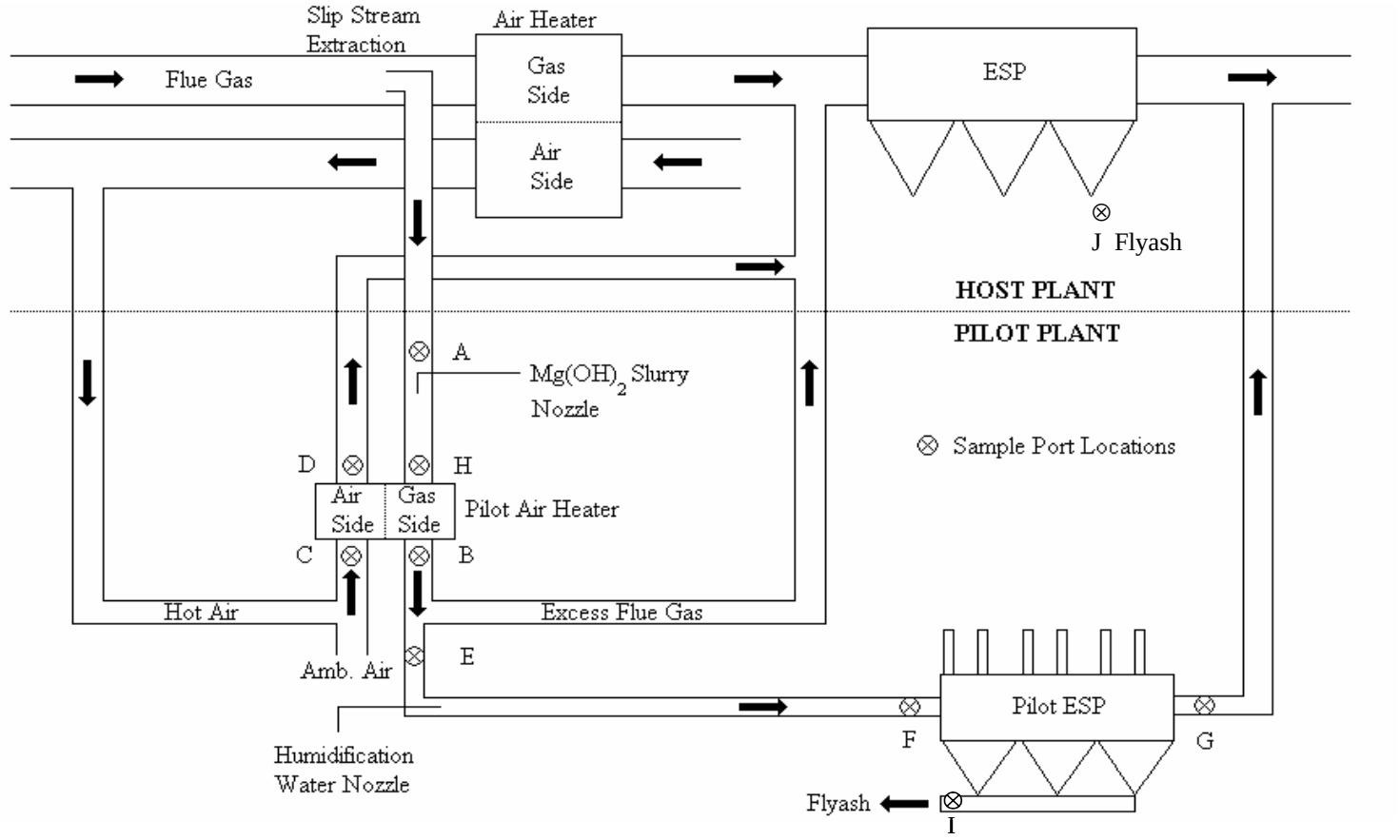
The pilot plant testing was conducted over the course of 15 months. Ancillary testing included evaluations of the performance of the air heater and electrostatic precipitator (ESP), a corrosion evaluation, and an evaluation of the stability of the mercury captured with the fly ash.

At baseline conditions (i.e.; at normal station operating conditions of 300 ^{o}F ESP inlet), mercury removal was about 25%. Mercury removal was sensitive to temperature and the concentration of unburned carbon in the fly ash. The Mitchell Station typically provided flue gas with fly ash containing 6 – 15% unburned carbon. At LTMC conditions of 200 – 210 ^{o}F at the ESP inlet, mercury removals of up to 96% were demonstrated. 90% mercury removal can be achieved by cooling the flue gas to 200 ^{o}F at the ESP inlet, provided that the fly ash contains 8% unburned carbon (assumes the coal contains 10% ash).

Injection of dilute magnesium hydroxide slurry, at a Mg/SO_3 molar ratio of 4/1, downstream of the economizer effectively removed sulfur trioxide to less than 3 ppmv at the air heater inlet and eliminated fouling of the air heater elements; this was true even during deep-cooling (<230 ^{o}F) periods of up to 75 hours with no sootblowing. The performance of the pilot ESP was not adversely affected by LTMC operating conditions (i.e; at very low SO_3 concentrations and low temperature).

The pilot plant program demonstrated that very high mercury removals, exceeding 90%, could be achieved by a fairly simple process. It appears likely that the process is most applicable to bituminous coals, because of the sensitivity of the mercury removal to unburned carbon content. No balance-of-plant problems were identified in the pilot program. These results justify larger-scale testing and demonstration.

Figure 1. Process Schematic of CONSOL/Allegheny Mercury Control Pilot Plant



Pilot Testing of Low-Temperature Mercury Control (LTMC) Process:

>90% MERCURY REMOVAL

CONTROL OF MERCURY EMISSIONS BY ABSORPTION ON FLYASH – FINAL EXPERIMENTAL RESULTS OF THE CONSOL/ALLEGHENY PILOT PLANT PROGRAM

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Lynn A. Brickett
US Dept. of Energy,
National Energy Technology Laboratory, Pgh., PA

LTMC Process

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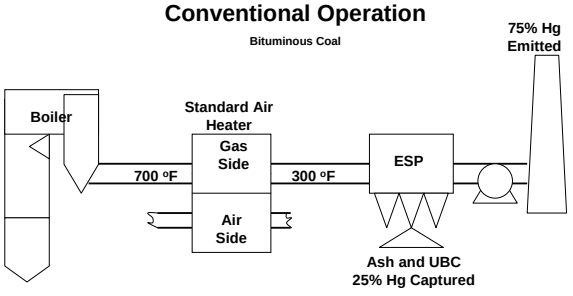
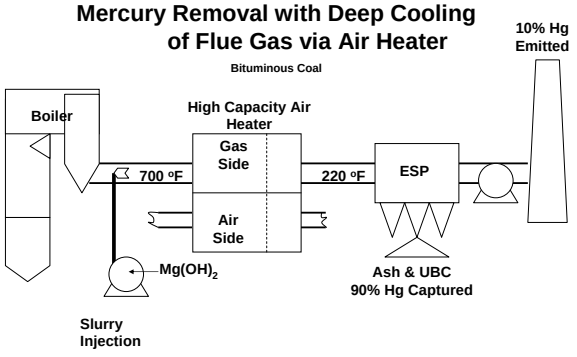
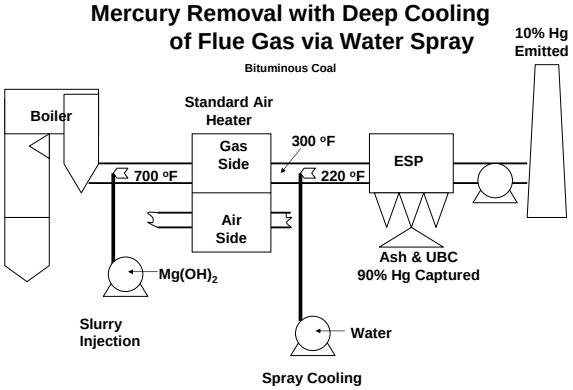
Conventional Operation



Mercury Removal with Deep Cooling of Flue Gas via Air Heater



Mercury Removal with Deep Cooling of Flue Gas via Water Spray



Host Plant
Allegheny Energy Mitchell Station

- Courtney, PA
- 288 MW Unit 3, corner fired
- In service 1963
- Thiosorbic lime wet FGD, ESP, no SCR
- Fired with north Appalachian bituminous coal
  S 3.0 - 4.8% Ash 9.3 – 15%
  Cl 0.05 - 0.09% Hg 0.09 - 0.13 ppm

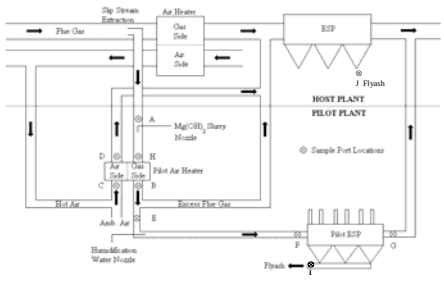
*Analyses on dry basis, except Hg as determined

Pilot Plant Program Description

CONSOL Energy and Allegheny Energy Supply, with support from the U.S. Department of Energy's National Energy Technology Laboratory, constructed and operated a pilot plant using flue gas from a coal-fired power generating station to develop the LTMC technology. Other participants in the development program were Alstom Power Inc., Environmental Elements Corp., and Carmeuse Lime, Inc. The performance of the process toward mercury removal and sulfur trioxide control, the influence of operating conditions, and the certain balance-of-plant impacts were evaluated at a 3640 scfm slip-stream pilot plant located at the Allegheny Energy Supply Mitchell Station in Courtney, PA. The pilot plant extracted flue gas immediately downstream of the Mitchell Station's economizer, and routed the extracted gas through a magnesium hydroxide slurry injection system, a pilot air heater, a water spray system, and a pilot electrostatic precipitator (ESP). During tests, samples of flue gas were taken at various locations in the pilot plant, and samples of fly ash were taken to determine the performance of the process. During the testing, the Mitchell Station burned high-sulfur northern Appalachian bituminous coal.

The pilot plant testing was conducted over the course of 15 months. Ancillary testing included evaluations of the performance of the air heater and electrostatic precipitator (ESP), a corrosion evaluation, and an evaluation of the stability of the mercury captured with the fly ash.

Mercury Control Pilot Plant
Flow Scheme



Pilot Plant Operating Conditions And Results

Test Condition	$Mg(OH)_2$ Injection?	ESP Flue Gas Temp., °F	Avg. (Range) "Carbon Treat Rate", lb C/million acf	Avg. (Range) Hg Removal Across ESP, %
Baseline	No	280 - 300	34 (22 - 53)	26 (9 - 39)
Short Term	Yes	230 - 250	23 (15 - 31)	49 (29 - 83)
Long Term	Yes	200 - 210	33 (15 - 51)	81 (61 - 96)

Pilot Plant Program Results

At baseline conditions (i.e.; at normal station operating conditions of 300 °F ESP inlet), mercury removal was about 25%. Mercury removal was sensitive to temperature and the concentration of unburned carbon in the fly ash. The Mitchell Station typically provided flue gas with fly ash containing 6 – 15% unburned carbon. At LTMC conditions of 200 – 210 °F at the ESP inlet, mercury removals of up to 96% were demonstrated. 90% mercury removal can be achieved by cooling the flue gas to 200 °F at the ESP inlet, provided that the fly ash contains 8% unburned carbon (assumes the coal contains 10% ash).

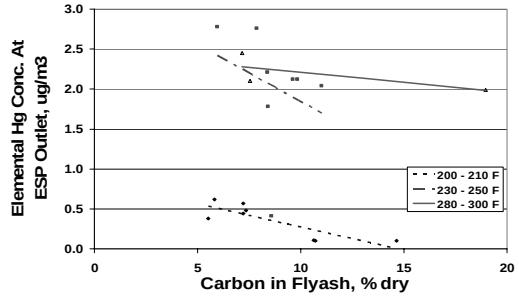
Injection of dilute magnesium hydroxide slurry, at a Mg/SO_3 molar ratio of 4/1, downstream of the economizer effectively removed sulfur trioxide to less than 3 ppmv at the air heater inlet and eliminated fouling of the air heater elements; this was true even during deep-cooling (<230 °F) periods of up to 75 hours with no sootblowing. The performance of the pilot ESP was not adversely affected by LTMC operating conditions (i.e; at very low SO_3 concentrations and low temperature).

The stability of the mercury captured by the fly ash was evaluated with leaching and volatilization tests. The captured mercury was stabile toward leaching at pH of 3 to 7 and was stabile toward volatilization at a temperature 140 °F.

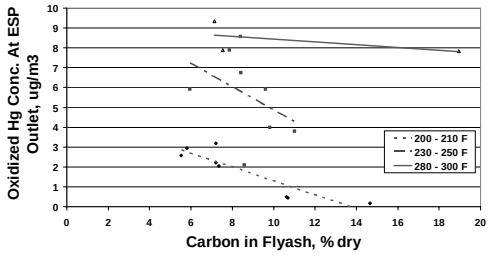
Effectiveness Of $Mg(OH)_2$ Injection For SO_3 Control

$Mg:SO_3$ Mole Ratio (Test Condition)	Avg. SO_3 Conc., ppm *(Acid Dew Pt., °F)*		SO_3 Removal, %
	Upstream of Mg Injection	Downstream of Mg Injection, Upstream of Air Heater	
None (Baseline)	12.5 *(274)*	-	-
2/1 (Short Term)	31.4 *(278)*	6.8 *(256)*	78%
4/1 (Short Term)	32.5 *(288)*	1.8 *(236)*	94%
4/1 (Long Term)	14.8 *(276)*	2.2 *(239)*	85%

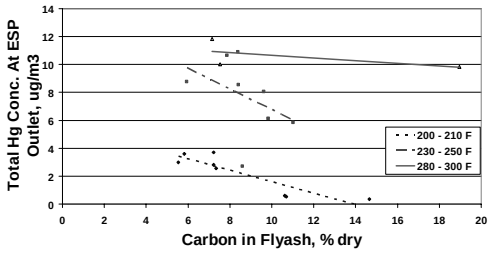
Elemental Hg Removed As Temperature Is Reduced



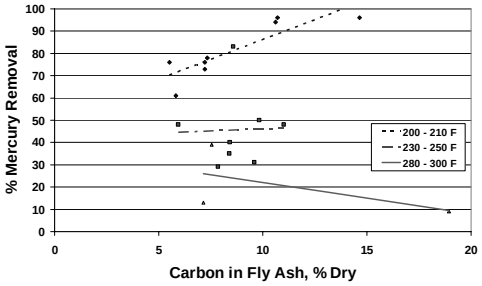
Oxidized Hg Removed As Temperature Is Reduced



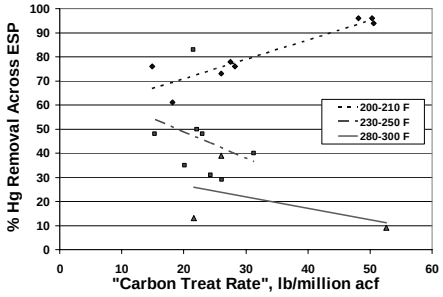
Total Hg Removed As Temperature Is Reduced



Hg Removed As Fly Ash Carbon Content Increases



Hg Removal Vs "Carbon Treat Rate"



Conclusions

- Over 90% mercury removal demonstrated with cooling to 200-210 ºF; baseline conditions gave about 26% removal (bituminous coal)
- Mercury removal sensitive to temperature and carbon content of fly ash
- At 200-210 ºF, both elemental and oxidized mercury effectively captured
- $Mg(OH)_2$ injection is effective for removal of SO_3 and eliminates rapid fouling of the air heater
- Pilot ESP performed satisfactorily at low temperature conditions
- Mercury volatility and leaching tests did not show any stability problems
- No significant corrosion detected at the air heater and on corrosion coupons at the ESP
- Results justify larger-scale testing/demonstration

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