DEPARTMENT OF ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY

Field Test Program to Develop Comprehensive Design, Operating, and Cost Data for Mercury Control Systems

Final Site Report for:
PG&E NEG Salem Harbor Station Unit 1
Sorbent Injection into a Cold-Side ESP for Mercury Control

U.S. DOE Cooperative Agreement No. DE-FC26-00NT41005
Topical Report No. 41005R18

Report Prepared for:
PG&E NEG
DOE NETL
EPRI

Report Prepared by:
ADA-ES
8100 SouthPark Way
Bldg. B
Littleton, CO 80120
(303) 734-1727

October 2004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

PG&E NEG Salem Harbor Station Unit 1 was successfully tested for applicability of activated carbon injection as a mercury control technology. Test results from this site have enabled a thorough evaluation of mercury control at Salem Harbor Unit 1, including performance, estimated cost, and operation data. This unit has very high native mercury removal, thus it was important to understand the impacts of process variables on native mercury capture.

The team responsible for executing this program included plant and PG&E headquarters personnel, EPRI and several of its member companies, DOE, ADA, Norit Americas, Inc., Hamon Research-Cottrell, Apogee Scientific, TRC Environmental Corporation, Reaction Engineering, as well as other laboratories. The technical support of all of these entities came together to make this program achieve its goals.

Overall the objectives of this field test program were to determine the mercury control and balance-of-plant impacts resulting from activated carbon injection into a full-scale ESP on Salem Harbor Unit 1, a low sulfur bituminous-coal-fired 86 MW unit. It was also important to understand the impacts of process variables on native mercury removal (>85%). One half of the gas stream was used for these tests, or 43 MWe. Activated carbon, DARCO FGD supplied by NORIT Americas, was injected upstream of the cold side ESP, just downstream of the air preheater. This allowed for approximately 1.5 seconds residence time in the duct before entering the ESP. Conditions tested in this field evaluation included the impacts of the Selective Non-Catalytic Reduction (SNCR) system on mercury capture, of unburned carbon in the fly ash, of adjusting ESP inlet flue gas temperatures, and of boiler load on mercury control.

The field evaluation conducted at Salem Harbor looked at several sorbent injection concentrations at several flue gas temperatures. It was noted that at the mid temperature range of 322-327°F, the LOI (unburned carbon) lost some of its ability to capture vapor phase Hg, however activated carbon performed relatively well. At the normal operating temperatures of 298-306°F, mercury emissions from the ESP were so low that both particulate and elemental mercury were “not detected” at the detection limits of the Ontario Hydro method for both baseline and injection tests. The oxidized mercury however, was 95% lower at a sorbent injection concentration of 10 lbs/MMacf compared with baseline emissions. When the flue gas temperatures were increased to a range of 343-347°F, mercury removal efficiencies were limited to <25%, even at the same sorbent injection concentration.

Other tests examined the impacts of fly ash LOI, operation of the SNCR system, and flue gas temperature on the native mercury capture without sorbent injection. Listed below are the main conclusions from this program:

- SNCR on/off test showed no beneficial effect on mercury removal caused by the SNCR system.
- At standard operating temperatures (~300°F), reducing LOI from 30-35% to 15-20% had minimal impact on Hg removal.
- Increasing flue gas temperatures reduced Hg removal regardless of LOI concentrations at Salem Harbor (minimum LOI was 15%). Native mercury

removal started to fall off at temperatures above 320°F. ACI effectiveness for mercury removal fell off at temperatures above 340°F.

- Test method detection limits play an important role at Salem Harbor due to the low residual emissions. Examining the proposed MA rule, both the removal efficiency and the emission concentrations will be difficult to demonstrate on an ongoing basis.
- Under tested conditions the baseline emissions met the proposed removal efficiency for 2006, but not the proposed emission concentration. ACI can meet the more-stringent 2012 emission limits, as long as measurement detection limits are lower than the Ontario Hydro method. SCEM testing was able to verify the low emissions. For ACI to perform at this level, process conditions need to match those obtained during testing.

INTRODUCTION

In December 2000 EPA announced its intent to regulate mercury emissions from the nation's coal-fired power plants. A great deal of research has been conducted in the decade preceding this announcement to characterize the emission and control of mercury compounds from the combustion of coal. Much of this research was funded by the Department of Energy, EPA, and EPRI. The results were summarized in 2000 in the comprehensive AWMA Critical Review Article[1]. As a result of these efforts, the following was determined:

1. Trace concentrations of mercury in flue gas can be measured relatively accurately;
2. Mercury is emitted in a variety of forms;
3. Mercury species vary with fuel source and combustion conditions; and
4. Control of mercury from utility boilers will be both difficult and expensive.

This latter point was one of the most important and dramatic findings from this research. Because of the large volumes of gas to be treated, low concentrations of mercury, and presence of difficult-to-capture species such as elemental mercury, some estimates show that 90% mercury reduction for utilities could cost the industry as much as $5 billion per year[1]. Most of these costs would be borne by power plants that burn low-sulfur coal and do not have wet scrubbers as part of the air pollution equipment.

With regulations rapidly approaching, it is important to concentrate efforts on the most mature retrofit control technologies. Injection of dry sorbents such as powdered activated carbon into the flue gas and further collection of the sorbent by ESPs and fabric filters represents the most mature and potentially most cost-effective control technology for power plants. However, all of the work through 2000 was conducted using bench-scale and pilot experiments. Although these reduced-scale programs provided valuable insight into many important issues, they could not fully account for impacts of additional control technology on plant-wide equipment.

Therefore, it was necessary to scale up the technology and perform full-scale field tests to document actual performance levels and determine accurate cost information. Under a DOE/NETL cooperative agreement, ADA worked in partnership with PG&E National Energy

Group (NEG), We-Energies, a subsidiary of Wisconsin Energy Corp. (also referred to interchangeably as Wisconsin Electric or Wisconsin Electric Power Company), Alabama Power Company, a subsidiary of Southern Company, and EPRI on a field evaluation program of sorbent injection upstream of existing particulate control devices for mercury control[2-4]. Other organizations that provided cost share to this program were Ontario Power Generation, First Energy, Hamon-Research Cottrell, TVA, Kennecott Energy, and Arch Coal. Team members included EPRI, Apogee Scientific, URS Corporation, Energy & Environmental Strategies, Reaction Engineering, Southern Research Institute, Hamon Research-Cottrell, Environmental Elements Corporation, Norit Americas, and EnviroCare International.

This report is the Site Report presenting results from the fourth and final field test conducted under this program. Tests were conducted at PG&E NEG's Salem Harbor Power Plant in the fall of 2002.

DESCRIPTION OF OVERALL PROGRAM

The Department of Energy's National Energy Technology Laboratory (NETL) was the primary funding agency on an industry cost-shared test program to obtain the necessary information to assess the costs of controlling mercury from coal-fired utility plants that do not have scrubbers for SO_2 control. The method for mercury control evaluated in this program is the injection of dry sorbents, such as activated carbon, upstream of the existing particulate control device on a full-scale system. The economics were developed based on various levels of mercury control at four different host sites. The four sites, shown below, fire coal types and have particulate control equipment that are representative of 75% of the coal-fired generation in the United States.

Test Site	Coal	Particulate Control
PG&E NEG Salem Harbor	Low S. Bituminous	Cold-Side ESP
PG&E NEG Brayton Point	Low S. Bituminous	Cold-Side ESP
We-Energies Pleasant Prairie	PRB (Subbituminous)	Cold-Side ESP
Alabama Power Gaston	Low S. Bituminous	Hot-Side ESP COHPAC FF

Salem Harbor Unit 1 was chosen for this evaluation because of its combination of firing low sulfur bituminous coal with urea-based SNCR, high LOI, and a cold-side ESP. Results from prior mercury tests have indicated 87 to 94% mercury removal efficiency on this unit, and a better understanding of the source of the high removal rates was desired. The site provided unique conditions that could be varied to determine the true impacts of process variables and of sorbent injection. Operating conditions were modified to the extent allowable to temporarily improve or reduce the mercury removal in order to understand how to optimize the performance in terms of both mercury capture and emissions compliance (for NO_x and particulate matter).

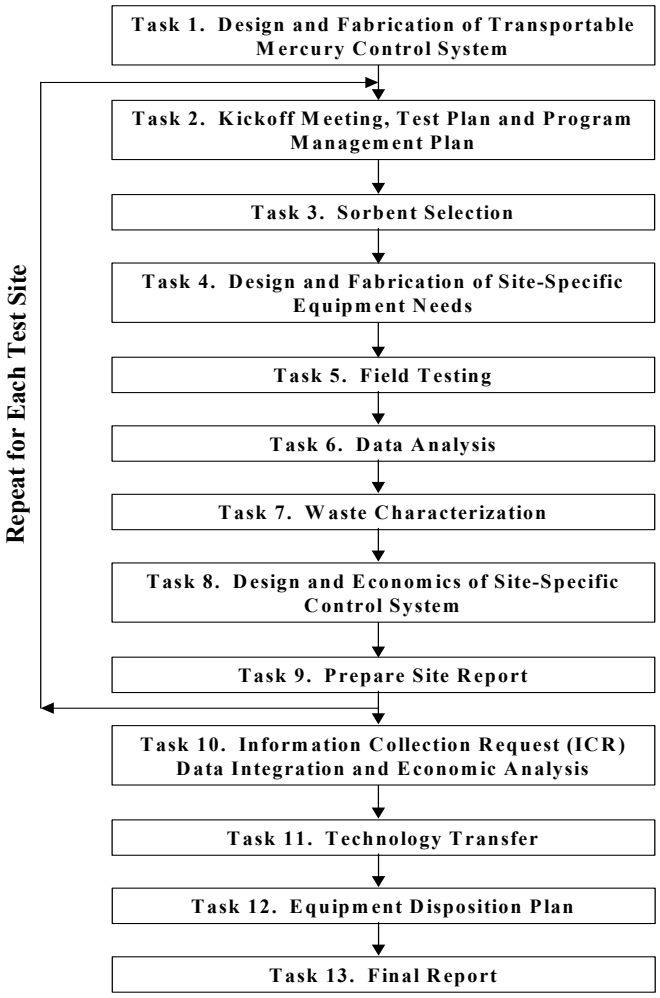
Salem Harbor Unit 1 had several regulatory and plant conditions that were of interest to this program, including:

1. PG&E NEG was evaluating mercury control options to meet new state compliance regulations in 2006. Sorbent injection is one of the viable options for mercury control.
2. Control rules were likely to be based on improvement over baseline performance, and thus an understanding of how to obtain further removal (above the ~80-90% removal efficiency baseline) is essential.
3. Salem Harbor utilizes a urea-based SNCR to help reduce NO_x emissions. The opportunity to quantify the impact of SNCR on mercury removal and sorbent effectiveness was unique.
4. Modification of process variables such as temperature, LOI, and SNCR would provide some insight into the main contributors of the high, native mercury removal. These results would provide insights into the variable that affect mercury control at other sites.

5. Four test locations were available for mercury measurements: economizer exit, air preheater outlet, ESP inlet, and ESP outlet. Using all locations allowed tests to be targeted specifically at measuring in-flight mercury capture vs. capture across the ESP.

The overall program had 12 technical tasks. Tasks 2 through 9 were specific for each of the field evaluations and Tasks 1, 10, 11 and 12 were common tasks in support of all the test sites. The technical tasks are shown on Figure 1.

Figure 1. Outline of Overall Program Technical Tasks.



This program was funded through a cooperative agreement between the Department of Energy National Energy Technology Laboratory (NETL) and ADA Environmental Solutions (ADA). The agreement included a requirement that industry cost share this program at a minimum of 33%. Under the DOE/NETL cooperative agreement, ADA worked in partnership with PG&E National Energy Group (NEG), Wisconsin Electric, a subsidiary of Wisconsin Energy Corp., Alabama Power Company, a subsidiary of Southern Company, and EPRI. Significant cost share was provided by industry for the Salem Harbor tests. Cost share partners were:

Wisconsin Electric Power Co.	**EPRI**
First Energy	**TVA**
EnviroCare	**Ontario Power**
Kennecott Energy	**Southern Company**
PG&E NEG	**Hamon Research-Cottrell**
Norit Americas, Inc.	**ADA**

SALEM HARBOR PROJECT OBJECTIVE AND TECHNICAL APPROACH

The overall objective of this project was to determine the performance and cost of activated carbon injection (ACI) into the cold side ESP for mercury control at PG&E NEG Salem Harbor Station Unit 1. This unit has very high native mercury removal. Thus, it was also important to understand the impacts of process variables on native mercury removal. Variables included in this evaluation were boiler load, unburned carbon in the fly ash, urea-based Selective Non-Catalytic Reduction (SNCR) NO_x reduction system operation, and flue gas temperature. The tests were conducted on ½ of the Unit 1 gas stream, nominally 43 MW.

To achieve the overall objective, the program was designed with an extensive field evaluation, laboratory testing, and analysis effort. This report presents the results of these efforts.

There were two objectives for the field evaluation. The first was to find out whether sorbent injection enhanced mercury removal beyond the baseline removal by fly ash . The second was to better understand the cause of the high, baseline mercury removal by varying process conditions. Variables that were evaluated included ESP operating temperatures, LOI/carbon content of the ash, and the use or non-use of SNCR. It had been speculated that Salem Harbor was unique in its high, baseline removal because of the combination of low flue gas temperatures, high LOI and SNCR.

A series of parametric tests were conducted to determine the optimum operating conditions for several levels of mercury control.

Only the benchmark sorbent, Norit America's Darco FGD, was evaluated during this program. The native ash at Salem Harbor was viewed as a second sorbent because of the high (90%) baseline removal. Therefore tests addressed both the injected sorbent, Darco FGD, and operating conditions that influence the native ash. The maximum sorbent injection rate was set based on practical limitations of ESP performance, measurable mercury removal, and cost. Based on results from parametric tests, a one-week test with activated carbon and optimized conditions was conducted to assess longer-term impacts to the ESP, ash and auxiliary equipment operation. During optimization mercury levels were measured with a semi-continuous emissions monitor (S-CEM). During the long-term test the S-CEM measurements were verified using Ontario Hydro method measurements.

SITE DESCRIPTION

PG&E National Energy Group owns and operates Salem Harbor Station located in Salem, Massachusetts. There are four fossil fuel fired units at the facility designated as Units 1, 2, 3, and 4. Units 1-3 fire a low sulfur, bituminous coal and use oil for startup. Unit 4 fires #6 fuel oil. Unit 1, which was the test unit, is a B&W single-wall-fired unit with twelve DB Riley CCV-90 burners. It is rated at 88 gross MW.

The particulate control equipment consists of a two-chamber, cold-side ESP (chambers designated 1-1 and 1-2), which provides two separate gas flow paths from the outlet of the tubular air heaters to the ID fan inlets. This Environmental Elements ESP has a rigid electrode

design and a specific collection area (SCA) of 474 ft^2/1000 acfm. The precipitator inlet gas temperature is nominally 255ºF at full load, according to plant instrumentation. A temperature traverse of the duct proved this temperature to be lower than the actual average, as presented in the Field Evaluation Section.

There are eight electrical fields in the direction of flow, and two across. A total of eight transformer-rectifier provide ESP power. The discharge electrodes are 44.5 feet in length and are spaced 18" apart in the direction of gas flow. There is a total of 171,108 square feet of collecting plate surface area.

There are eight precipitator ash hoppers on Unit 1, four in the direction of flow and two across. A pneumatic conveying system ties into each hopper and blows dry ash into the fly ash storage silo, where it is combined with fly ash from the ESPs, economizer hoppers, and air preheater hoppers from Units 1, 2 and 3. Both wet and dry unloading systems are available to feed the ash from the fly ash storage silo into a truck.

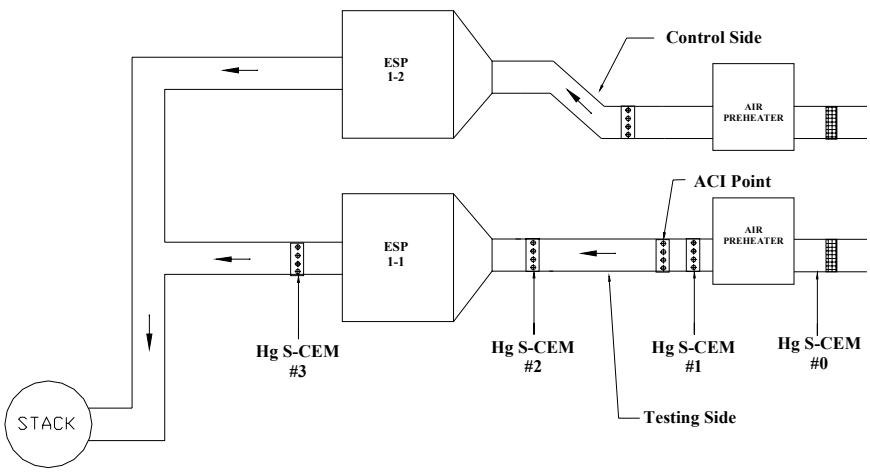
Typical LOI / carbon content of the Unit 1 ash is about 35%. This ash is landfilled.
A summary of important descriptive parameters for Salem Harbor Unit 1 is presented in Table 1.

Table 1. Site Description Summary, Salem Harbor Unit 1

PARAMETER IDENTIFICATION	DESCRIPTION
Boiler Manufacturer	B&W 85 MW Radiant Boiler
Burner Type	DB Riley CCV-90
Low NOx Burners	Yes
Steam Coils	Yes
Over Fire Air	No
NOx Control (Post Combustion)	SNCR
Temperature (APH Outlet)	255
Coal	
Type	South American Bituminous
Heating Value (Btu/lb)	12701
Moisture (%)	9.64
Sulfur (%)	0.63
Ash (%)	3.92
Hg (μg/g)	0.03
Cl (μg/g)	206
Control Device	
Type	Cold-Side ESP
ESP Manufacturer	Environmental Elements
Design	Cold-Side, Rigid-Electrode
Specific Collection Area (ft^2/1000afcm)	474
Flue Gas Conditioning	None

Figures 2 and 3 show schematics of the Unit 1 ESPs at Salem Harbor. Figure 2 shows the duct work downstream of the economizer, with the S-CEM locations identified, and Figure 3 shows the path of the flue gas with the locations of sorbent injection and ESP inlet and outlet ports.

Figure 2. Schematic of Salem Harbor Unit 1 Ductwork showing S-CEM Locations.



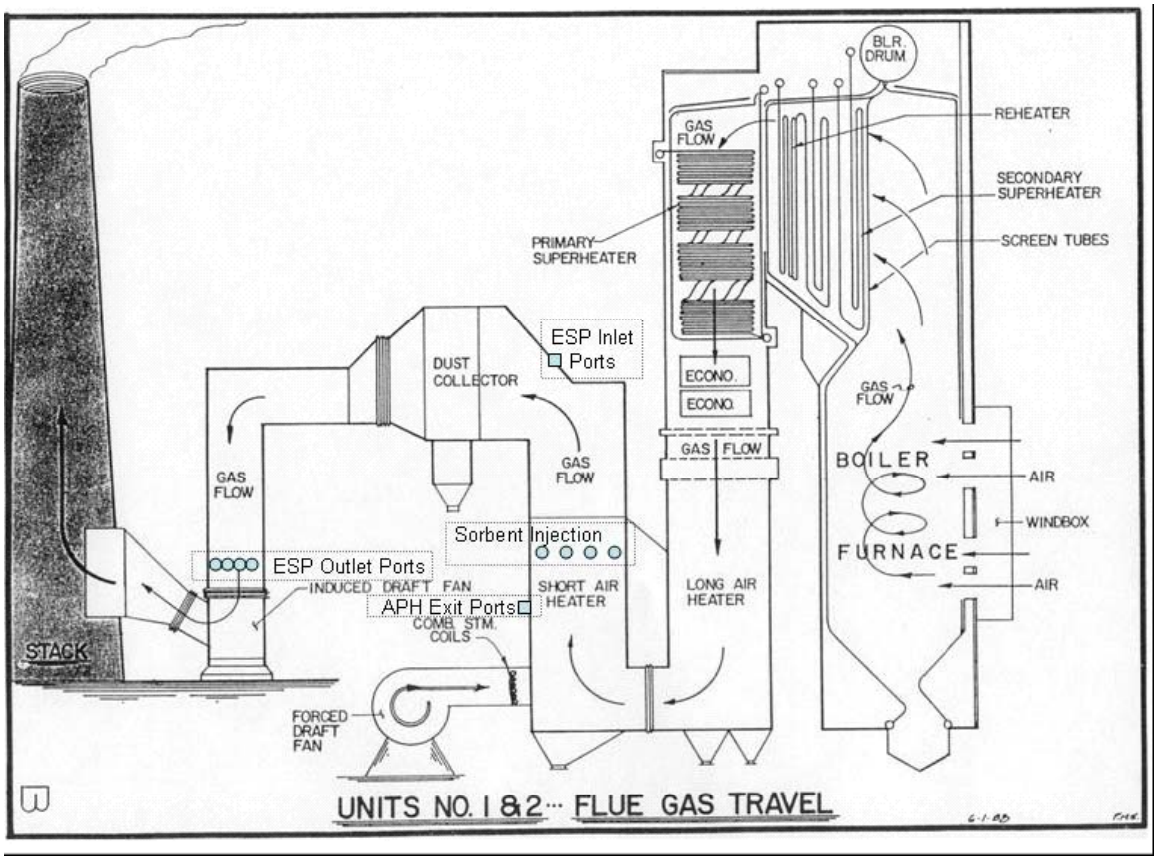


Figure 3. Flue Gas Path at Salem Harbor Unit 1.

FIELD EVALUATION

The critical elements of the site evaluation were the actual field tests and measurements, which relied upon accurate, rapid measurements of mercury concentration and an injection system that realistically represented commercially-available technology.

Near real-time, vapor-phase mercury measurements were made using a Semi-Continuous Emissions Monitors (S-CEM) designed and operated by Apogee Scientific. This instrument was developed with EPRI funding to facilitate EPRI research and development efforts[5]. Multiple S-CEMs were used. The locations of the analyzers are shown on Figure 2. The S-CEMs operated continuously for over seven weeks, providing speciated, vapor-phase mercury concentrations at four locations along the flue gas path: the APH inlet, APH outlet, ESP inlet, and ESP outlet. Two locations were measured at any one time.

Unit operation variables were a major focus at Salem Harbor because of the high baseline mercury removal. LOI, urea injection, and flue gas temperature were three variables that were tested in addition to sorbent injection. A CAMRAC LOI analyzer was used to monitor the LOI in the economizer exit duct on Salem Harbor Unit 1 during these tests.

For sorbent injection, a portable, dilute-phase pneumatic injection system and the distribution and injection components of the system.

A Test Plan for this program at Salem Harbor was developed prior to commencing testing, it is included in Appendix A. Meetings were held with plant, project and environmental personnel to finalize the scope and logistics of the test program. Pre-baseline tests were performed in February 2001 and results were used in the development of the test matrix herein. Injection equipment was installed in August 2002. Injection ports were installed during a unit outage in the second week of September 2002. Testing started the week of September 16, and continued into November 2002.

The overall schedule for equipment installation and tests conducted for the Salem Harbor Unit 1 evaluation is shown in Table 2.

Table 2. Schedule of Salem Harbor Unit 1 Mercury Control Evaluation

Test Description	Dates
Pre-Baseline tests	February 2001
Site Visit and Pre-Test Meeting	July 16, 2002
Equipment Installation	August 2002
Port Installation	Early September 2002
Urea On/Off tests	Sep 16-20, 2002
Baseline Tests	Sep 23-27, 2002
Parametric Tests	Oct 7-18, 2002
Long Term Tests	Nov 16-22, 2002
Ash / sample and data analyses	Nov 2002-Sep 2003

Site-Specific Equipment Description

Sorbent requirements were difficult to predict for Salem Harbor Unit 1 because of the high baseline removal (87-94%) and the low mercury concentrations (3-4 μg/Nm^3). Ultimately the maximum injection rate was estimated based on experience from other sites and to assure that there was sufficient turndown of the injection rate. The range selected for injection equipment design was 5-20 lb/MMacf, which corresponded to 52 to 210 lb/hr.

The sorbent injection equipment feeder was supplied by Norit Americas. This skid-mounted dry injection system pneumatically conveys an adjustable amount of activated carbon from bulk bags to the injection locations. Activated carbon is metered using a volumetric feeder into a pneumatic eductor, where air supplied from a regenerative blower provides the motive force to transport the carbon to the injection lances. Figure 4 shows the temporary feeder installed at Salem Harbor. A programmable logic controller (PLC) was used to control system operation and adjust feed rates. The feeder had an injection range of 0 – 300 lbs/h. Activated carbon was carried from the feeder to a distribution manifold at the injection location via flexible hose. The distribution manifold was designed to supply up to six injection lances. At this site, there were four injection lances inserted horizontally into the vertical duct. Each lance was made from 1-inch pipe and had a single nozzle created by cutting the end at a 45 degree angle. The probes were staggered to achieve good distribution.

Figure 4. Carbon PortaPAC (blue) at Salem Harbor.

Description of Field Tests

The test series at Salem Harbor was unique in that it focused on process variables in addition to injection of sorbent. Other variables of interest were temperature, SNCR on/off, and LOI/carbon in the ash. The feasibility and methodology for controlling these parameters was determined with input from all team members.

The field tests were separated into five different test phases:

- Urea On/Off;
- Baseline;
- Parametric Tests without sorbent injection;
- Parametric Tests with sorbent injection; and
- Long-Term Tests.

Test methods are described first, followed by a description of the five test phases. Results from the laboratory and field tests are presented in a separate "Salem Harbor Test Results" Section.

1. Test Methods used in Field Testing at Salem Harbor

A comprehensive test plan was developed for the tests at Salem Harbor Unit 1 (Appendix A). This document describes the test methodology and quality control procedures used. Pre-baseline results from 2001 are described in Appendix B to the test plan. Detailed descriptions of the Ontario-Hydro method and laboratory analyses procedures were provided by TRC prior to testing, and are included in Appendix C (the test plan's Appendix C has been updated to reflect the final version of the QAPP). Appendix A of the test plan has a detailed description of the S-CEM used for continuous mercury monitoring.

S-CEM measurements were conducted at various times at four different locations, as shown in Figure 2. The S-CEMs were all located on the duct work feeding ESP 1-1. All tests were conducted on half the unit (~ 43 MW), with the south duct being the control side and the north duct (ESP 1-1) being the test side. Initially only three S-S-CEM locations were setup. The first S-CEM extraction location (#1) was immediately downstream (~ 10') of the air preheater. The second S-CEM extraction location (#2) was located approximately 65 feet downstream of location #1 and approximately 30' upstream of the ESP. Comparing data between these two locations (#1 & #2) provided information on the in-flight, vapor-phase mercury removal. The third location (#3) for mercury measurements was located at the outlet of the ESP, on the I.D. fan inlet duct downstream of the ESP. A fourth location (#0) was added during the tests to obtain mercury readings upstream of the air preheater. This location was used during selected tests to observe the shift in speciation and the in-flight removal of the vapor-phase mercury from the economizer exit forward.

Ontario Hydro measurements for mercury were made by TRC Environmental during the baseline and long-term tests. TRC also conducted EPA Method 29 tests at the same time to quantify multi-metals at the inlet and outlet of the ESP. EPA Method 26 tests were conducted to measure HCl at the ESP inlet during both baseline and long-term tests. NH_3 was measured during long term tests at the ESP inlet. In conjunction with these tests, TRC measured the flue gas O_2, CO_2, moisture, and velocity. Sample locations were at the inlet and/or outlet of the 1-1 ESP.

A CAMRAC LOI analyzer was used to measure LOI at the economizer outlet in a batch fashion during much of the testing. This instrument uses microwave-based technology to provide near real-time, in-situ LOI measurements. Ash samples were also taken for manual LOI determination.

2. Urea (SNCR) On / Off Testing

The injection of urea via an SNCR system is a variable that has not previously been proven to (or not to) affect mercury capture, and there has been some debate in the industry as to its potential effect. Since turning off SNCR has serious implications for Salem Harbor's NO_x compliance, an approach that provided a clean test of the impact of SNCR while minimizing the amount of time that SNCR was turned off, was developed.

Testing SNCR's impact on mercury is more complex than just turning off the reagent flow. The residual ammonia on the unit's internal surfaces and in the fly ash may continue to affect mercury removal or speciation after SNCR is turned off. Approaches to obtaining an ammonia-free test would be either to leave the urea off for a long period of time, several days, or to begin the test series with a "clean unit" after the outage, prior to turning on urea injection at all. The latter approach was used, enabling testing of "baseline" conditions without SNCR. The clean-furnace condition after startup gave the operators the maximum flexibility to control NO_x and mitigate the effect of turning off SNCR.

On September 16, 2002 about noon Salem Harbor Unit 1 was brought on line with the SNCR system out of service. On September 18 the SNCR system was put into service at about 1300 hours, with the unit at full load and S-CEM measuring mercury across the ESP. Two manual ammonia measurements were made after urea was turned on. The results are presented in the Test Results section.

3. Baseline Testing

With the unit running normally with SNCR in service for several days, baseline testing was conducted the week of September 23-26, 2002. During this test boiler load was held steady at "full-load" conditions (86 MW) 24 hours per day. Both the S-CEMs and the Ontario Hydro Method were used to measure mercury across the 1-1 ESP. One Ontario Hydro test set (inlet and outlet of the ESP, simultaneous measurements) was made each day on September 23, 24, and 25. Multi-metals testing using Method 29 was also conducted. HCl using EPA Method 26 and ammonia were also measured at the ESP inlet. Vapor-phase mercury removal was measured using the S-CEM at the ESP inlet and outlet.

In addition to monitoring mercury removal, it was also important to document impacts on ESP performance with and without sorbent injection. This is critical to the success of sorbent injection for mercury control on any ESP system. All tests, including baseline, parametric, and long-term tests, included monitoring of opacity. Apart from opacity, the primary performance indicator for an ESP is power level. The higher the power level, the better the performance. Power is measured in kW and was also monitored throughout all testing. Changes in particulate matter characteristics such as resistivity, which is changed by carbon, can affect ESP performance. The results are presented and discussed under the Long Term Test Results section.

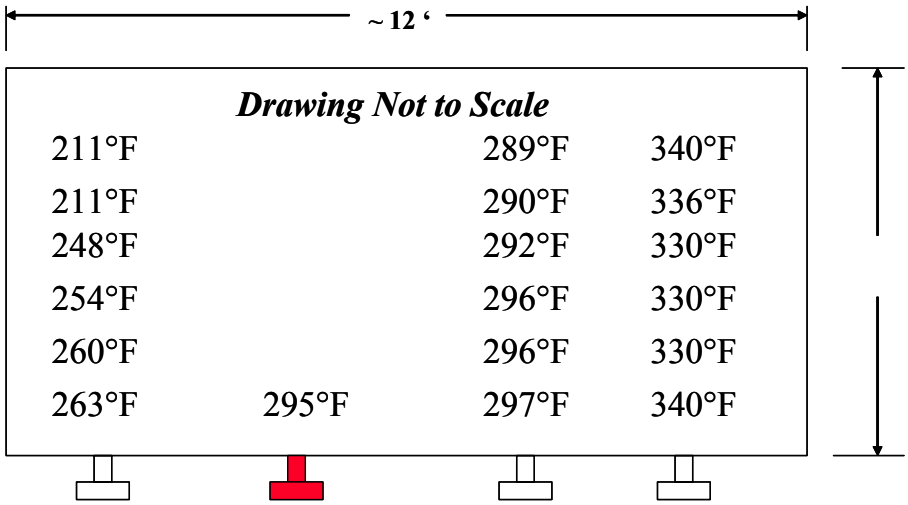
During the baseline tests, daily samples of coal and ESP hopper ash were collected.

4. Parametric Testing – No Sorbent Injection

Salem Harbor Unit 1 was unique in this DOE program in that the ash itself was considered an effective sorbent for mercury, and process conditions were targeted that would reveal the impacts of mercury control when unit operation changed. The two main parameters of interest were flue gas temperature and LOI/carbon in the ash. These were first evaluated from September 26-28 without sorbent injection.

The Unit's steam coil was used to increase the temperature of the flue gas. Plant instrumentation had indicated an average ESP inlet flue gas temperature of 255ºF, but this was found to be not representative of the duct average, as shown on Figure 5. The measured ESP average temperature of about 290ºF showed a large variation across the inlet duct. The large variation in temperature provides some cooler temperature areas which are well-suited to mercury capture by sorbent, especially oxidized mercury. It also has hotter pockets that may be above the ideal temperature for effective mercury adsorption. This temperature effect on sorption can apply to the native ash as well as activated carbon. A test that increased the overall flue gas temperature in two steps was planned. The steam coils were used to effect this change. At a partial setting on the steam coils, the temperature could be increased to about 325°F on average. At the full setting, the flue gas average temperature was about 340-350°F. The temperature range achievable for mercury tests was determined during a pre-test of Unit 1 during the week of September 3, 2002. These settings were then used to establish operating conditions during the remainder of testing.

Figure 5. As-found temperature distribution at APH outlet duct, Salem Harbor Unit 1. Gas flow is into the page.

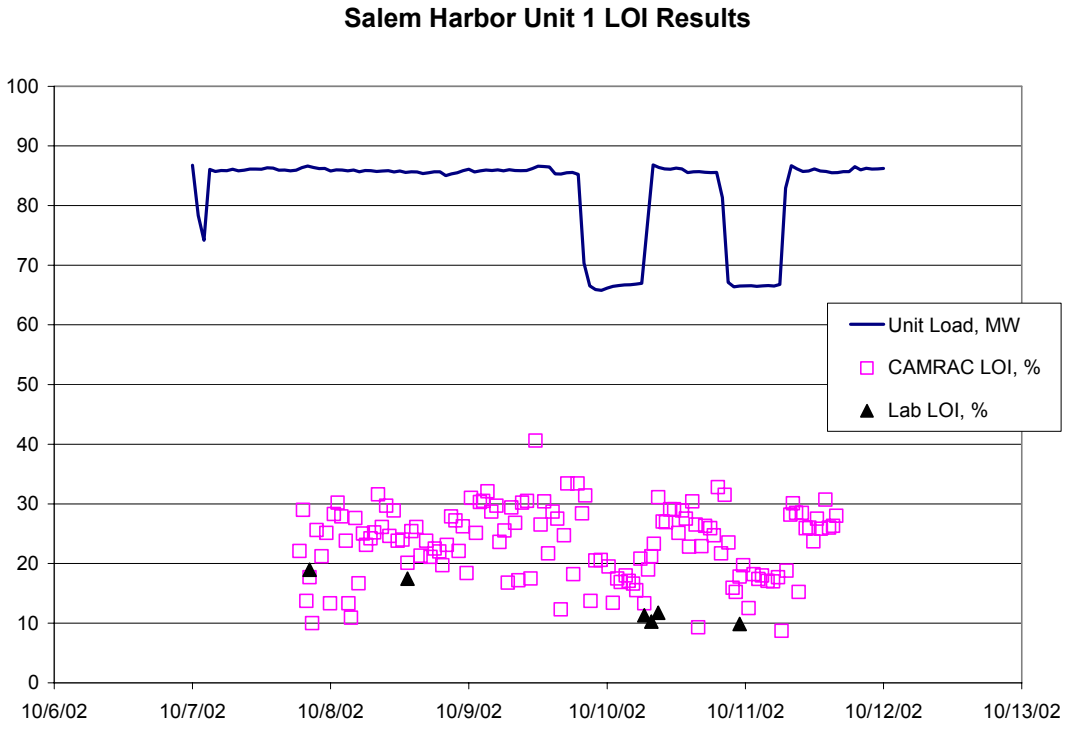


LOI/carbon content in the ash is typically about 35%. Based on data from other sites, it was expected that this variable would be a significant contributor to the mercury removal at Salem Harbor. Tests at multiple levels of LOI/carbon and flue gas temperature combinations would provide valuable information on the correlation of LOI with mercury control. These tests also provided baseline comparative data for the sorbent injection tests conducted later. To vary LOI, modifications were made to unit operation that were not standard and that were very site-specific.

Some preliminary testing was conducted the week of September 3 to examine operating variables that may affect LOI. Using an on-line LOI analyzer (CAMRAC) located at Location 0 on Figure 2 (the economizer exit), changes in LOI could be evaluated in real time. The CAMRAC takes a batch sample over several minutes to an hour, and provides an LOI reading on that ash sample. It was calibrated by comparing results from plant laboratory measurements of samples provided from the APH inlet location by ADA. The results from the calibration are shown in Figure 6. It was determined that a decrease in boiler load from 85 to about 65 MW

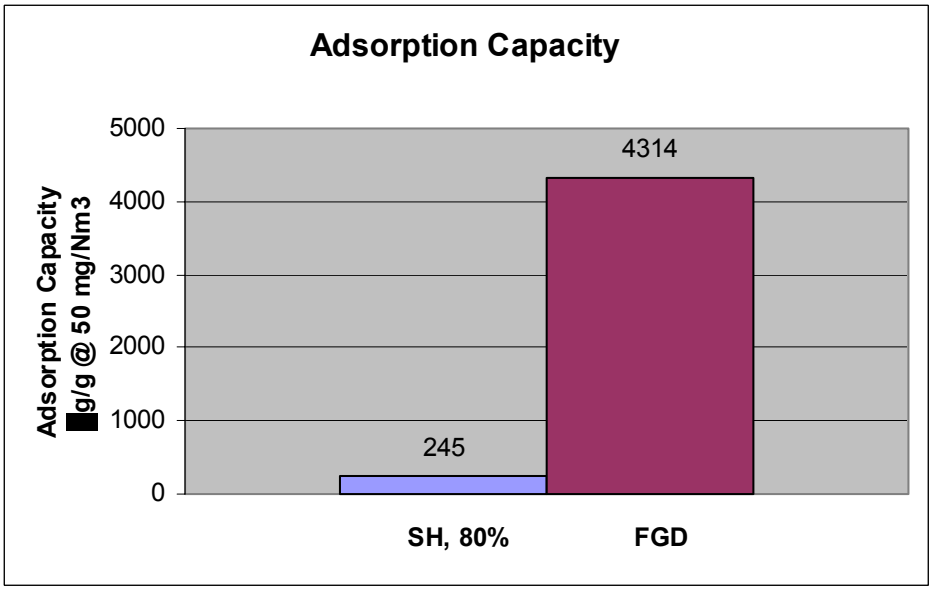
with all mills in service, in conjunction with an increase in excess air, lowered LOI from about 35% to about 20% (both readings based on the on-line CAMRAC). Reduction in LOI below the 18-20% level was not feasible.

Figure 6. On-line CAMRAC readings compared with lab analyses for LOI at various boiler loads, Salem Harbor Unit 1.



Prior to these field tests, adsorption capacity of the LOI at Salem Harbor Unit 1 was evaluated in the laboratory by URS Corporation using their fixed-bed slipstream device. This was done to develop a better understanding of how effective the LOI in the ash is as a mercury sorbent, and how various levels of LOI may impact mercury capture. The approach was to concentrate an ash sample to 80% LOI and use the fixed-bed laboratory device to compare the adsorption capacity with that of Darco FGD. The result of the comparison is shown on Figure 7.

Figure 7. Relative mercury adsorption capacity of Salem Harbor LOI/carbon as compared with Darco FGD activated carbon. URS Corporation.



Treating LOI as equivalent to carbon content, these data were then compared in terms of adsorption effectiveness. With the lower adsorption capacity of the LOI carbon in comparison with FGD carbon, an equivalent injection ratio was calculated. Table 3 shows, for LOI levels in the range measured during field tests, the amount of carbon that would have to be injected to yield that LOI ("Injection Concentration" column), and the amount of FGD that would be injected for an equivalent mercury adsorption capacity ("Equivalent FGD Injection Concentration" column). This provides a point of comparison for LOI effectiveness for mercury control when evaluating field test results in the Test Results section below. More information on the ash characteristics is provided in the Coal and Waste Characterization section.

Table 3. LOI/carbon quantities and effectiveness when compared with injected AC

LOI %	Injection Concentration (lbs/MMacf)	Equivalent FGD Injection Concentration (lbs/MMacf) *
10	24	1.36
15	36	2.04
20	48	2.73
25	60	3.41
30	72	4.09
35	84	4.77

*Note: other parameters factor into mercury capture, these values are provided for reference.

4. Parametric Testing – Sorbent Injection

Sorbent injection was tested at various operating conditions, to determine whether further removal beyond the nominally 90% baseline removal was possible, and to determine whether activated carbon injection could enhance removal when process conditions resulted in less than 90% removal. These tests were conducted October 7-18, 2002.

Only one sorbent was used in this parametric test series to minimize the number of variables. The sorbent was a standard powdered activated carbon, Darco FGD, supplied by Norit Americas. The primary variables were:

- Sorbent injection concentration,
- Flue gas temperature, and
- Ash LOI level.

The parametric conditions tested are shown in Table 4. During the parametric tests, the S-CEMs were used to quantify mercury control effectiveness of each tested condition.

Table 4. Summary of Parametric Test Conditions, Salem Harbor Unit 1

Load	Average Temperature at Location 1 (APH outlet)	Target Injection Concentration (Darco FGD, lb/MMacf)
High Load ~ 85-86 MW	High ~ 345-350 ^{o}F	0, 10, 20
High Load ~ 85-86 MW	Medium ~ 325 ^{o}F	0, 5, 10, 20
High Load ~ 83-87 MW	Normal ~ 300-305 ^{o}F	0, 5, 10, 20
Low Load ~ 66-67 MW	Normal ~ 280-287 ^{o}F	0, 5, 10

Using test locations at the economizer exit (Figure 2) and the ESP inlet, an attempt was made to measure in-flight mercury removal between the injection point and the ESP inlet. Any mercury removal between the APH outlet (location 1) and ESP inlet (location 2) could be attributed to the injected sorbent, since the ash did not remove significant mercury in this zone.

Prior to the start of the sorbent-injection parametric tests on October 7, 2002, a new coal was delivered to Salem Harbor from South America, Drummond coal. This coal was different from that fired during baseline tests, and was fired during the parametric ACI tests.

Mercury control test results from this series are included in the Test Results section. Coal and ash analysis summaries are included after the Test Results section under "Coal and Ash Characterization."

5. Long-Term Performance Tests

The long-term performance test plan included some repeat conditions from the parametric test series as well as a four-day continuous injection test at 10 lb/MMacf. The tests were conducted November 16-22, 2002. The repeated conditions were ACI injection at 10 and 20 lb/MMacf at normal flue gas temperatures (300-305^{o}F). The conditions for the continuous injection test from

November 19-22 were determined based on results from the parametric tests and the most interesting conditions for long-term predictions. The long term test conditions included:

- Full load 24 hours per day;
- SNCR in service as normal;
- 10 lb/MMacf ACI; and
- Elevated flue gas temperatures using partial steam coils, targeted for 325°F at the air preheater outlet (location 1). At this temperature the effect of ACI could be clearly seen because LOI effectiveness for mercury capture starts to fall off.

Similar to the baseline series, multi-metals (Method 29) and Ontario Hydro tests were conducted. Flue gas ammonia and HCl concentrations were also measured. Coal and ash samples were taken and analyzed for comparison with other test results. These results are presented in the following section.

SALEM HARBOR TEST RESULTS

Field testing on Salem Harbor Unit 1 was concluded on November 22, 2002. The test series and dates of testing were summarized in Table 2.

Results are presented separately for each test series in the subsections below. Results from coal and ash analyses for all test series are presented and discussed together under "Coal and Ash Characterization." Cost data is provided in the final subsection "Economic Analysis." Conclusions are summarized in the final report section.

UREA (SNCR) OFF/ON TEST RESULTS

The SNCR system was left off line for two days as the unit was started up in September 2002. This provided a window of time for measurements without the system in service. On September 18 the SNCR system was put into service as normal. Unit 1, SNCR system operation, and NOx emissions during this period are shown on Figure 8. The results of SNCR on/off tests were documented in a memo of September 20, 2002, which is included in Appendix B.

Figure 8. Boiler load, NOx emissions and urea flow during the SNCR on/off tests.

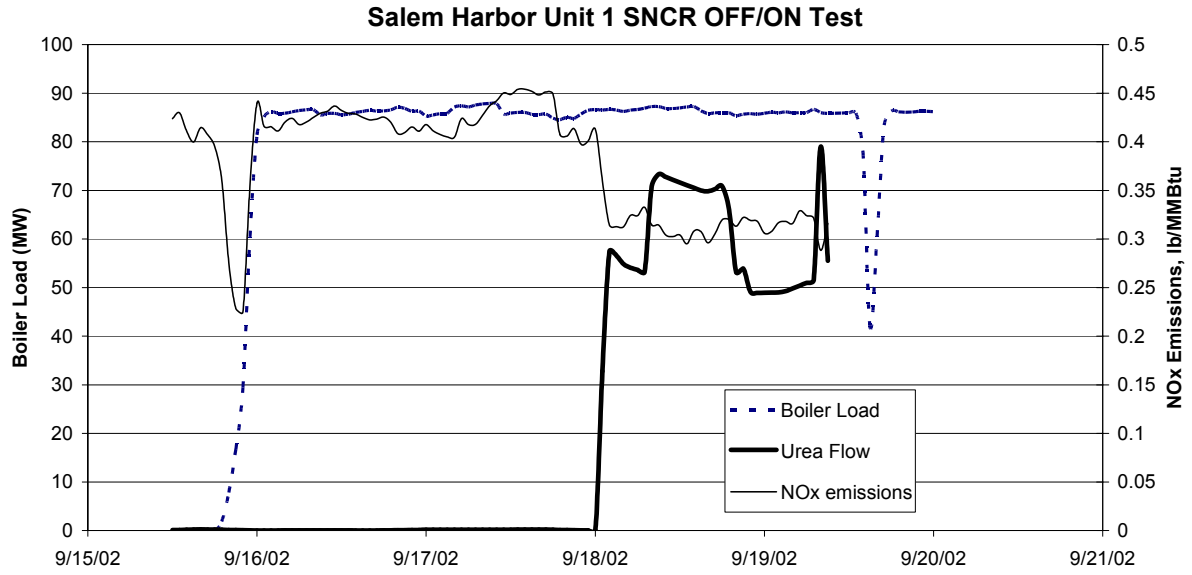
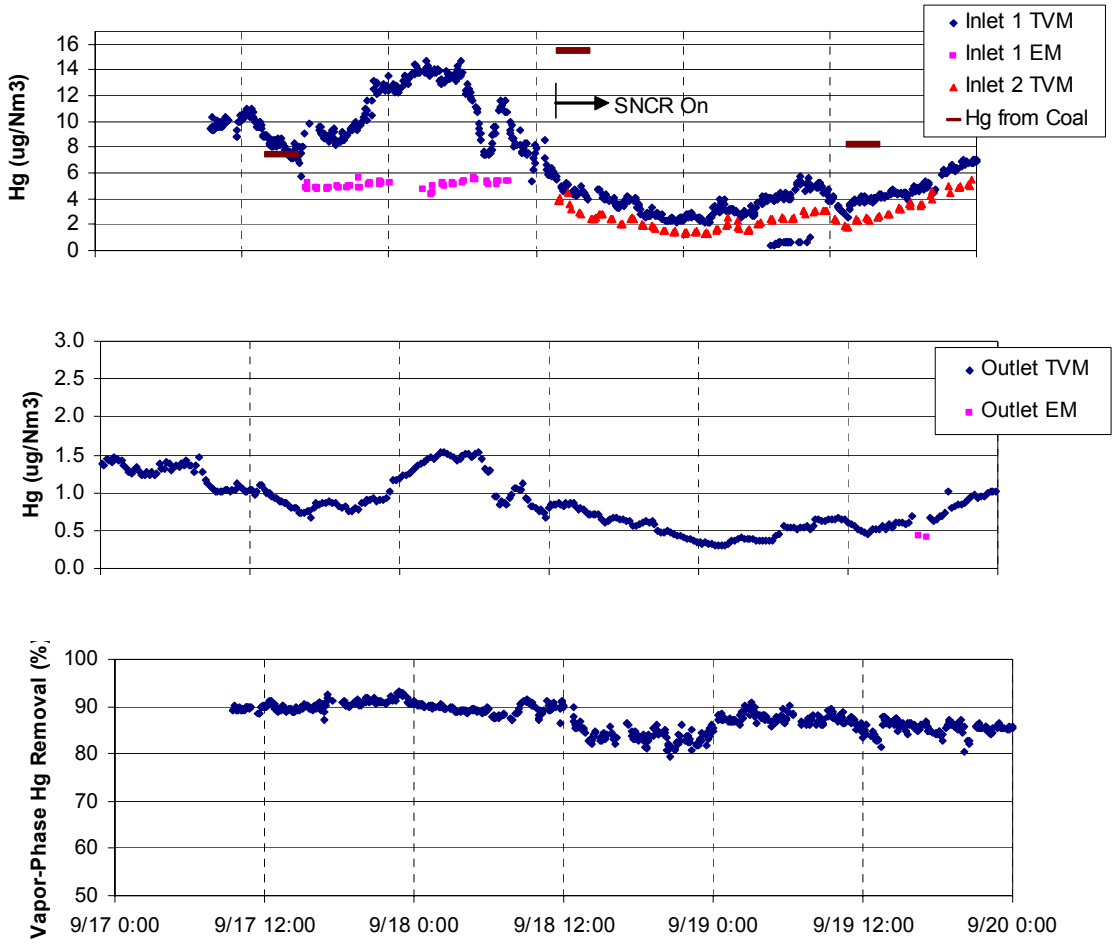


Figure 8 shows that fully two days of unit operation took place prior to the urea being turned on and that when the urea was turned on, NO_x reacted immediately with a drop from about 0.4 lb/MMBtu to 0.3-0.33 lb/MMBtu. The normal target operation for the SNCR system is a setpoint around 0.31 lb/MMBtu, under the regulatory limit of 0.33 lb/MMBtu NO_x at the stack.

Mercury measurements were made during this period as well. Figure 9 shows the results of these measurements.

Figure 9. S-CEM measurements during the SNCR off/on period September 16-18, 2002.



Mercury measurements and removal efficiency during the urea off/on tests are shown in Figure 9. This figure indicates when the urea system was turned on. Mercury was measured at two inlet locations (1 and 2) and at the outlet. Speciated mercury was measured at location 1. Interestingly, total mercury measured during this period was higher than usually indicated in previous tests. Coal mercury levels were measured in two samples on the 16th at 7 µg/dncm, one on the 18th at 15 µg/dncm, and one on the 19th at 8 µg/dncm. These measurements are also shown on the top graph and confirm that a higher mercury coal was being burned at this time.

Mercury removal percentages were very consistent with previous tests at about 80-90%. Inlet and outlet levels can be seen in Figure 9 to trend together over time. The measurements made between locations Inlet 1 (TVM) and Inlet 2 (TVM) after urea was turned on (top chart on Figure 9) show that about 20-30% of the vapor-phase mercury is removed in-flight, upstream of the ESP. The start of urea injection does not appear to influence the mercury removal.

Ammonia measurements made on the 18th with the SNCR system in service showed <1 to 3 ppm of ammonia in the flue gas. Urea injection, shown on Figure 8, was at a rate of 55-62 gpm. This

compares with the usual full-load injection range of 50-80 gpm. Sootblowers were in constant service from the time the unit came on line, so that the operators could maintain the best possible NO_x emissions. The clean furnace and constant sootblowing condition probably contributed to the urea requirement to maintain NO_x compliance being at the low end of the range for these initial tests.

BASELINE TEST RESULTS

During Baseline tests, September 23-25, mercury in the flue gas was measured with the S-CEMs and by the Ontario Hydro test method. In addition coal and ash samples were collected. Results of coal and ash analyses are tabulated and discussed in the Section below entitled "Coal and Ash Characterization."

Preliminary results from Baseline tests were summarized in a memo dated October 3, 2002. This memo is included for reference in Appendix C. Baseline test conditions were normal, full-load operation, 24 hours a day.

Ontario Hydro results are shown in Table 5. As with prior testing high mercury control is indicated at about 88% removal. No elemental mercury was detected in any sample. A large portion (~97%) of the total mercury is already in the ash at the inlet test location, or is adsorbed onto the ash in the sample train. This is shown in Table 5 as particulate mercury. Oxidized mercury increased across the ESP but is very low, <0.5 μg/dncm.

Figure 10 shows S-CEM measurements during the same time frame as the Ontario Hydro runs. The S-CEM measured 2-6 μg/dncm of vapor-phase mercury at the air preheater outlet (Inlet 1 on the figure). ESP Inlet and outlet measurements are seen to trend together across the time span. Comparing Inlets 1 and 2 on 9/23, the S-CEM measurements show that vapor phase mercury is removed between the air preheater outlet (Inlet 1 TVM) and the ESP inlet (Inlet 2 TVM). However 2-4 μg/dncm remains in the vapor phase at location 2. This is greater than indicated by the Ontario Hydro method, which shows <0.36 μg/dncm of mercury in the vapor form at the same location (ESP inlet).

Outlet measurements made by the S-CEM confirm that some mercury is emitted from Salem Harbor Unit 1, in the range of ~0.3 to 1.3 μg/dncm. The Ontario Hydro tests alone do not give a good metric of actual emissions since this site has emissions that are very close to the detection limit for this method. This is important for compliance demonstration at very low levels, as will be required in Massachusetts if the mercury control provisions of 310 CMR 7.29 are finalized. This is discussed further under the Long Term Testing Results section.

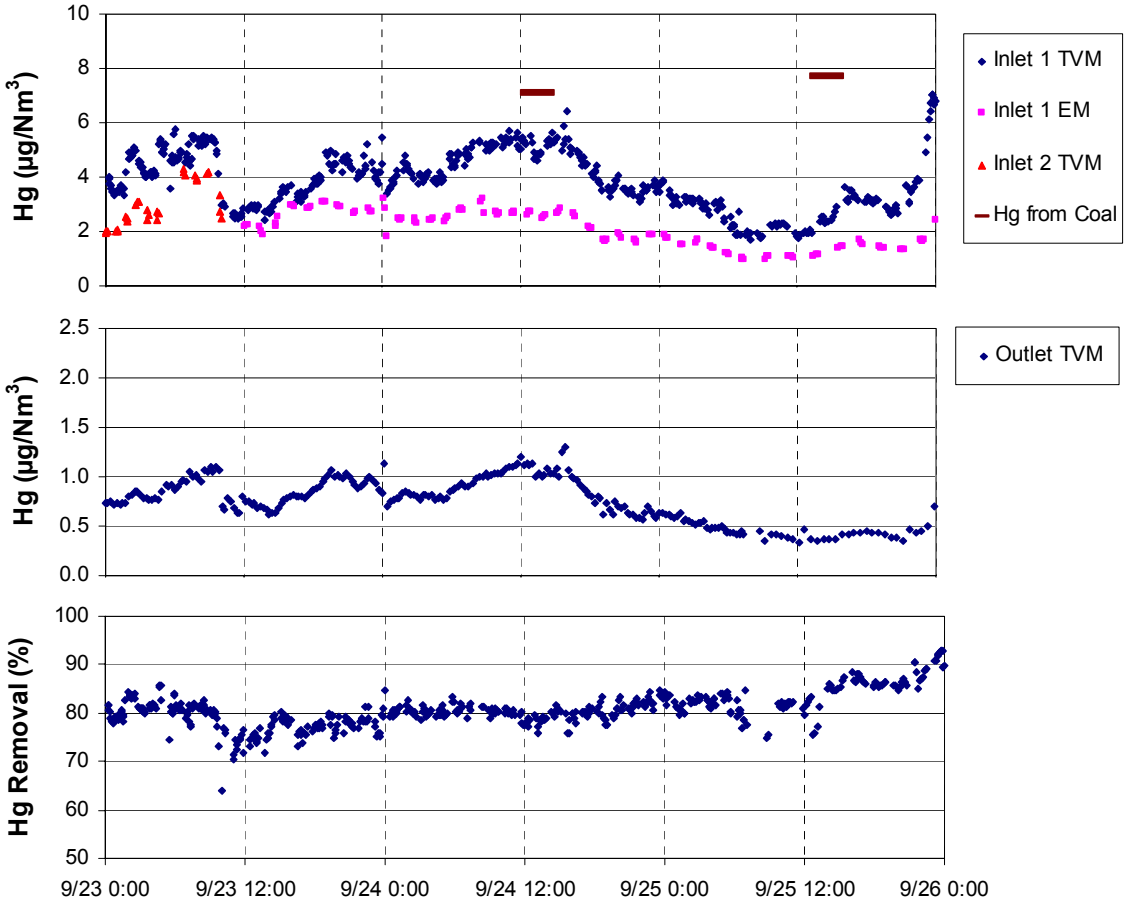
Table 5. Speciated Mercury Measured by Ontario Hydro Method, Baseline Conditions. Average of Three Runs, Salem Harbor Unit 1

	Particulate (µg/dncm)	Elemental (µg/dncm)	Oxidized (µg/dncm)	Total (µg/dncm)
ESP Inlet	10.15	ND<0.27	0.09	<10.51*
ESP Outlet	ND<0.34	ND<0.50	0.41	<1.25
Removal Efficiency (%)	>97%	--	Increase	**~88%**
% of Total at Inlet	97%	2.6%	0.9%	--
% of Total at Outlet	**27%**	**40%**	**33%**	--

Note: all mercury numbers are µg/dscm at 32 F, 3% O_2.
* Individual test runs were 7 to 14 µg/dncm.

Three coal samples from 9/23, 9/24, and 9/25/02, during the baseline tests, were analyzed for mercury and showed concentrations of 0.07-0.08 µg/g. At Salem Harbor this coal mercury level is equivalent to a mercury concentration of about 7-8 µg/dncm @ 3% O_2 in the flue gas.

Figure 10. Baseline S-CEM Data from Salem Harbor. All measurements, including removal percentages, are vapor-phase mercury only.

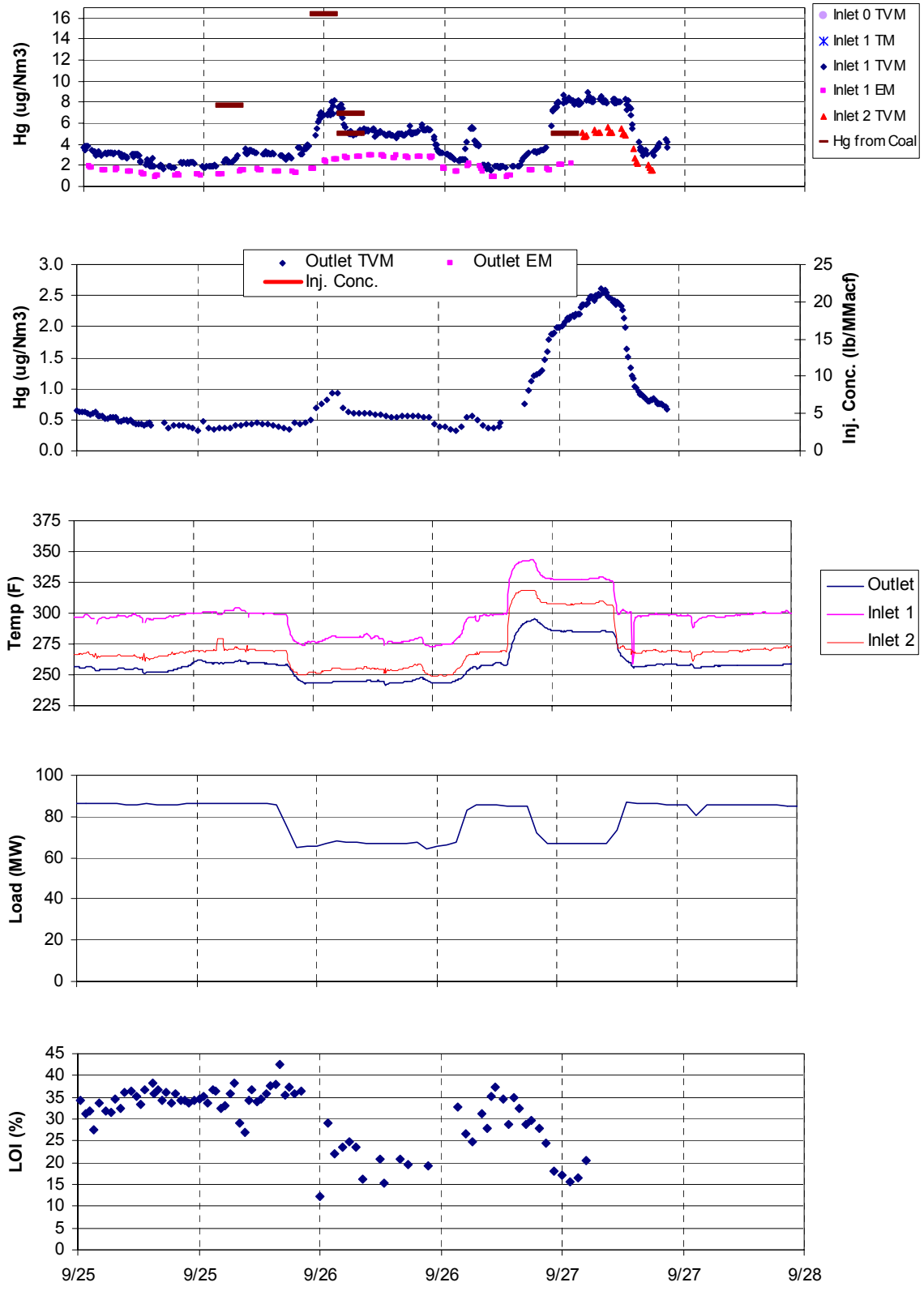


PARAMETRIC TEST RESULTS – NO SORBENT INJECTION

Parametric testing without sorbent injection evaluated mercury removal as a function of flue gas temperature and of fly ash LOI. These tests were conducted during the same week as baseline tests, starting on the evening of September 25 after Ontario Hydro tests were complete. Results from this week, during which these parametric tests without sorbent injection were conducted September 25-27, are included as mentioned above in Appendix C. Parametric test series both with and without sorbent injection were summarized in a memo dated October 21, 2002. This memo is provided in Appendix D. Major results and observations are presented here and in the following subsection.

The first series of tests without sorbent injection evaluated the impact of reducing load, and consequently LOI, on the native mercury removal at Salem Harbor Unit 1. Late on September 25 boiler load was reduced to 65 MW, with a drop in LOI from about 35% to about 20% (CAMRAC readings). No significant change was seen in mercury control. Although there was a brief uptick in mercury at the inlet and outlet of the ESP when this change was made, once things stabilized the outlet mercury levels recovered to about 0.5 μg/dncm (Figure 11). It is possible that the range of operational flexibility, taking LOI from 35% to 20%, was not sufficient to demonstrate any reduction in mercury removal efficiency due to reduced LOI. The quantity of LOI/carbon in the flue gas equated as shown in Table 3 to 3-5 lb/MMacf of activated carbon. Reducing LOI below 10%, although not feasible during this test series, may show a reduced mercury control impact.

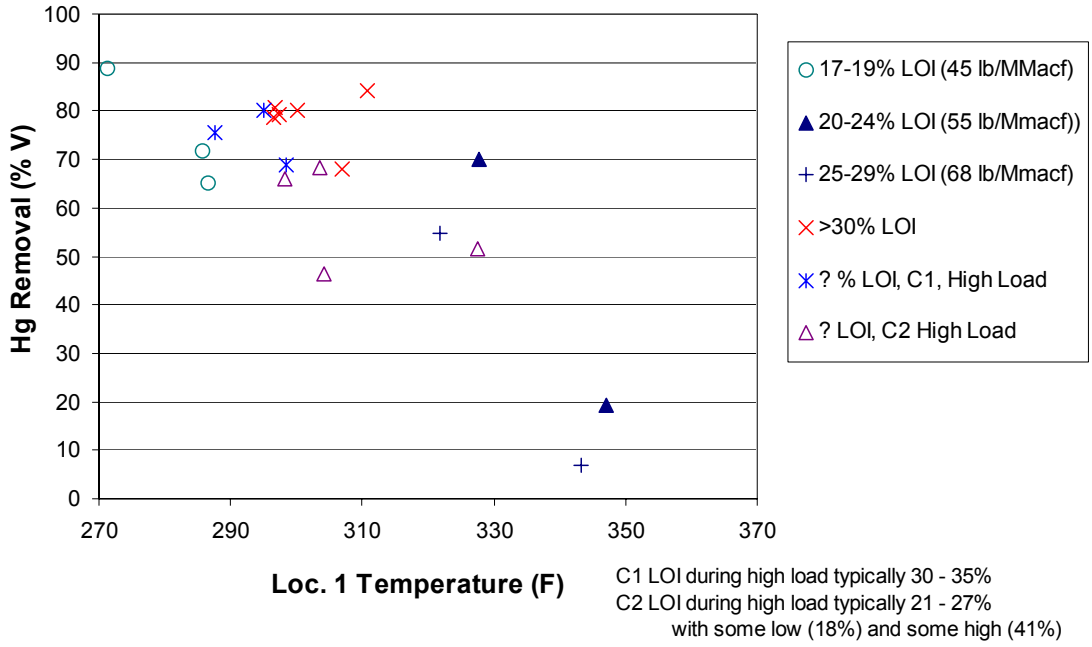
Figure 11. S-CEM mercury levels and process conditions during the initial parametric tests with no sorbent injection. Salem Harbor Unit 1, September 25-27, 2002.



Following the decreased LOI test, in which no discernable impact was made on mercury control, the next evening the flue gas temperature was increased at the low load/low LOI condition. This was achieved as described previously by implementing the steam coils for the air preheater. Mercury levels again increased with the transient process changes, but this time the outlet mercury increased significantly also. In this case, the larger impact on mercury emissions appeared to be temperature and not LOI. Combined conditions of low LOI and high temperature on the second night of testing resulted in mercury removals on the order of 70%.

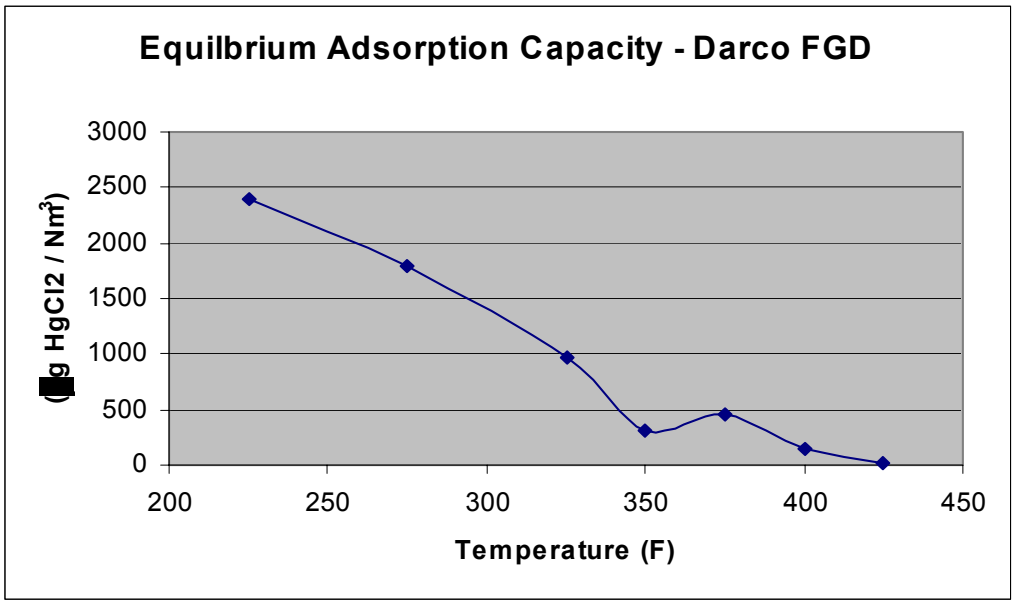
This temperature effect was confirmed in subsequent tests, summarized on Figure 12. This figure shows a limitation of the ability of the native ash to control mercury as temperature rises. This effect is not surprising given the temperature dependence between mercury adsorption and activated carbon and other sorbents. Figure 13 shows the decrease in adsorption capacity of PAC that occurs in the laboratory as flue gas temperature is increased.

Figure 12. Mercury control with no sorbent injection as a function of temperature. Various LOI, coal, and load conditions.



Five coal mercury analyses made on coal collected during this period are also shown on Figure 11. With one exception (a high coal reading on 9/26) the coal mercury matches S-CEM data well. The coal shows 5 to 8 µg/dncm while the S-CEM reads 2-8 µg/dncm at location 1.

Figure 13. URS Corporation data on the effect of temperature on Darco FGD adsorption capacity for mercury.



PARAMETRIC TEST RESULTS – WITH SORBENT INJECTION

A new test coal from Columbia, South America was fired during the Parametric test series starting on October 7. This coal had a lower sulfur content and a lower heating value as compared to the coal fired at the Salem Harbor station during the baseline testing series. In general, the new test coal produced lower vapor-phase mercury concentrations at the air heater outlet.

Detailed results from this series are presented in the October 21, 2002 memo included in Appendix D. Highlights and graphical summaries of the two weeks of parametric tests are presented here.

In this parametric test series, the primary variables were sorbent injection concentration and temperature. Injection concentrations were varied from 5 to 20 lb/MMacf. Four temperatures ranges were tested, varying from 280-347^{o}F. A summary of the test results is presented on Figure 14. Vapor phase mercury removal, as measured by the S-CEMs from upstream of sorbent injection (Location 1) to downstream of the ESP (Location 3) is shown. One data set is noted, where the removal efficiency is calculated just across the ESP (Locations 2 to 3).

Trendlines are shown for each of four temperature ranges. With or without sorbent injection, flue gas temperatures above 340 ^{o}F suppress sorbent adsorption of mercury. This can be seen with the significantly lower removal efficiencies in the 343-347^{o}F temperature range at all injection concentrations. Mercury removal can also clearly be improved with sorbent injection at all temperatures over 300 ^{o}F. At 10 lb/MMacf sorbent, removal is limited to <25% at the higher

temperature. Note that native removal of vapor-phase mercury between the air preheater outlet and the ESP outlet ranges from about 10% to 70% and is very temperature sensitive.

Figure 14. Vapor-Phase mercury removal at Salem Harbor Unit 1 as a function of sorbent injection rate and flue gas temperature.

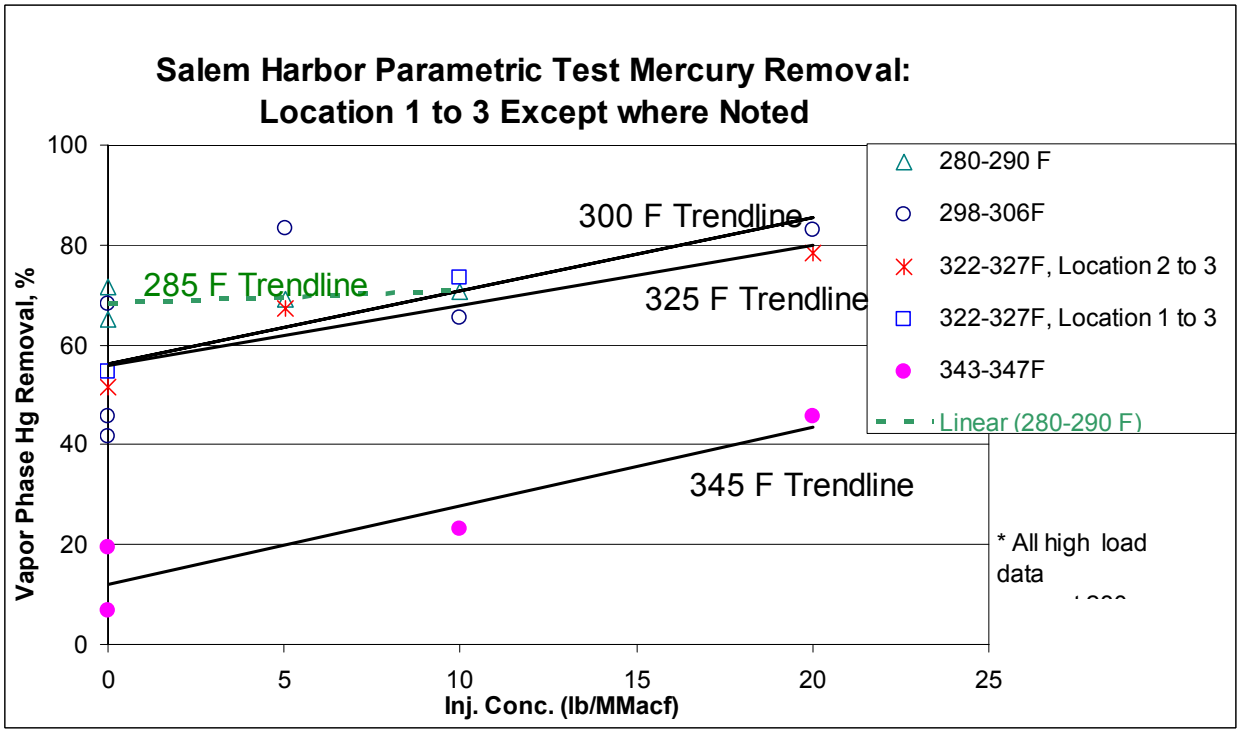


Figure 15. In-flight and incremental mercury removal for baseline and ACI conditions, Salem Harbor Unit 1. "Pre"= no sorbent injection; "Post" = with sorbent injection; numbers indicate mercury measurement locations as shown on Figure 2.

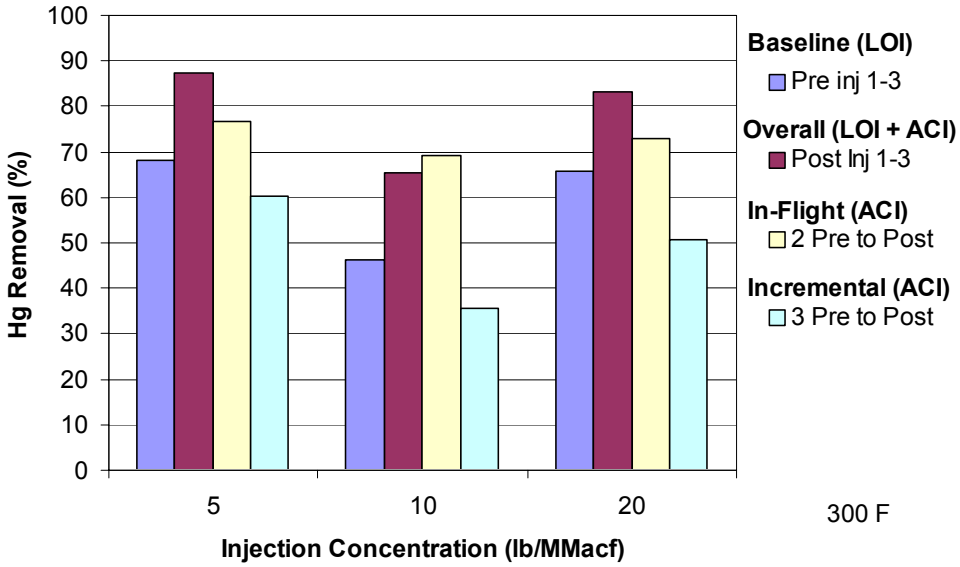


Figure 15 shows mercury removal between the various locations at different sorbent injection conditions. These data reveal that overall mercury capture across the ESP by the sorbent (measured between locations 1 and 3; shown as the first two bars in each set on the figure) improves when sorbent is injected as compared to the ash alone. The figure also shows that in-flight mercury capture, as indicated at location 2, is significant (~70-75% capture). Finally, incremental mercury removal by ACI is examined as a function of the sorbent injection rate (the final bar in each data set on the figure), and is seen to range from ~35-60%.

Parametric Test Summary

A different coal than that used in the baseline tests was fired during the parametric test series. Several process conditions were examined during the test series, including load, LOI, flue gas temperature, SNCR on/off, and ACI concentration.

The conclusions from these tests were:

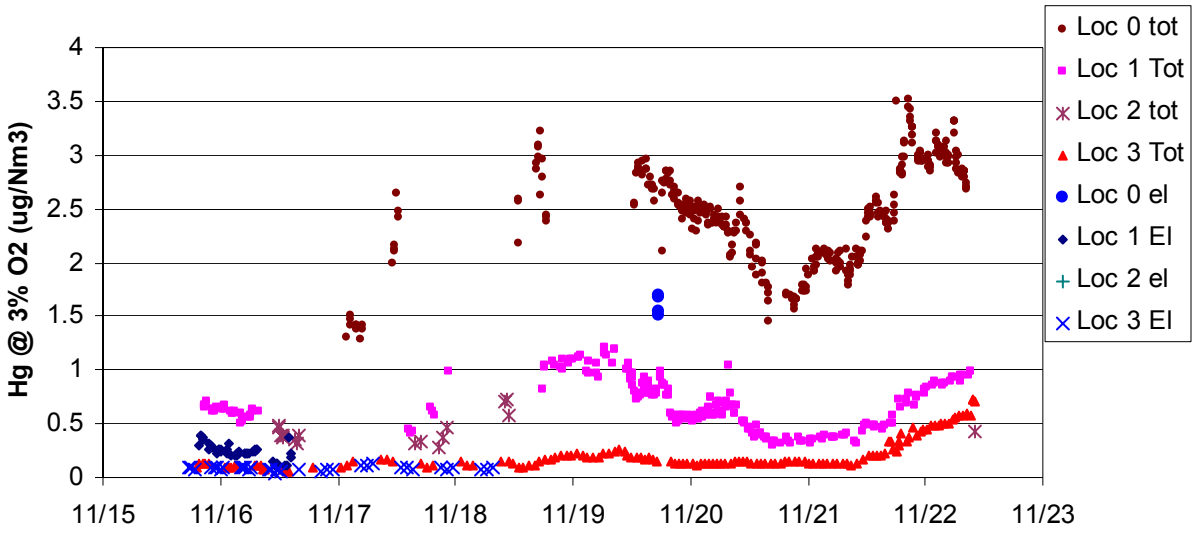
- SNCR on/off test showed that SNCR did not improve mercury removal.
- At standard operating temperatures (300°F), reducing LOI from about 30% to 15-20% had minimal impact on mercury removal.
- Increasing temperature reduced mercury removal regardless of LOI at Salem Harbor.
- At this site, temperature had a greater impact on mercury removal than LOI at the LOI levels tested (>15% LOI).
- ACI had a small effect on overall Hg removal at standard operating temperatures.
- An observed improvement to mercury removal efficiency was seen with ACI at temperatures > 310°F.
- Activated carbon was less effective capturing mercury at higher temperatures (> 340°F).
    - Capacity data show that oxidized mercury is more sensitive to temperature than elemental mercury.
- In flight data suggests that ACI would be effective without the high LOI.
    - ACI is more reactive than LOI carbon and more tolerant of increased flue gas temperatures.

LONG-TERM TEST RESULTS

A Memo summarizing long-term test results was issued November 27, 2002 and is included in Appendix E. The major results are presented and discussed here. Coal and ash analyses are presented in the following subsection.

Measurements were conducted periodically at all four locations and are shown on Figure 16. The vapor-phase mercury during these tests was very low, in the range of 1.5-4 µg/dncm upstream of the air preheater, dropping across the air preheater to 0.3 to 1.3 µg/dncm. Because of the low concentrations at most of the measurement locations, long sampling times were required by the S-CEMs (longer sample times provide lower detection limits for mercury), limiting the number of samples that could be taken for elemental vs. total mercury.

Figure 16. Vapor-phase mercury trends as measured by the S-CEMs during long-term test series, Salem Harbor Unit 1.



Triplicate Ontario Hydro measurements were made on November 21, 2002. As shown in Table 6, the vapor-phase mercury levels are very low, with elemental mercury less than the method detection limit at both the inlet and outlet locations. Coal mercury analyses obtained during the long-term tests showed a range of 5 to 8 µg/dncm. The major differences between this result with ACI and the baseline tests (Table 5) without ACI are:

- The total mercury (upstream of the ESP) during long-term tests was about half that present during the baseline series (5.24 vs. 10.5 µg/dncm);
- Oxidized mercury increased across the ESP during baseline tests, while it was removed by the ACI during long-term tests;
- The residual mercury indicated for both baseline and long-term tests is predominantly based on method detection limits and not on actual readings. Oxidized mercury has a

lower detection limit than particulate or elemental. The oxidized mercury that is emitted drops from 0.41 to 0.02 µg/dncm with the addition of the ACI (cf. Table 5 with Table 6 outlet oxidized mercury).

- S-CEM measurements during baseline testing confirm that some mercury is emitted, in the range of ~0.3 to 1.3 µg/dncm. This corresponds to about 0.0033 to 0.0145 lb/GW-hr. In comparison, the optimized testing during the one-week ACI resulted in emissions generally in the range of 0.15 to 0.25 µg/dncm (although emissions did increase towards the end of this run to over 0.5 µg/dncm). This corresponds to about 0.0016 to 0.0027 lb/GW-hr.

Table 6. Ontario Hydro results from long term test on November 21, 2002 at Salem Harbor Unit 1. 10 lb/MMacf ACI

	Particulate (µg/dncm)	**Elemental (µg/dncm)**	**Oxidized (µg/dncm)**	**Total (µg/dncm)**
ESP Inlet	4.9	ND<0.27	0.07	<5.24
ESP Outlet	ND<0.09	ND<0.51	0.02	<0.62
Removal Efficiency (%)	>98%	--	70%	**~88%**
% of Total at Inlet	94%	2.6%	0.9%	--
% of Total at Outlet	15%	82%	3%	--

Note: all mercury numbers are µg/dscm at 32 ^{o}F, 3% O_2.

For a comparison of mercury control provisions of 310 CMR 7.29 to these test results, the following discussion is provided. The draft revision to 310 CMR 7.29 proposes that coal-fired facilities must meet the targets in Table 7. These targets are very low for mercury emission measurement. The Ontario Hydro method cannot consistently detect mercury at the level proposed for 2012. Even the measurement of mercury at 0.68 µg/dncm is risky using the Ontario Hydro method. By January 1, 2008 the same rule requires a CEMS for mercury measurements to be installed and operated. If compliance demonstrations are required before that time, an alternative test method could be used to obtain lower detection levels. EPA now has a draft Method 324 (sorbent tube method) for mercury measurements, which team members on this project have used extensively with good success. This method can obtain either short (30-minutes) or long-term integrated grab samples of mercury and also obtain detection limits that are lower than the Ontario Hydro method. Mercury detection levels for the sorbent tube method can be obtained as low as 0.03 µg/dncm (approximately 0.0004 lb/GW-hr at Salem Harbor).

Table 7. Target mercury emissions in the proposed revisions to 310 CMR 7.29

Effective Date	October 1, 2006	October 1, 2012
Mercury limit, lb/GW-hr	0.0075	0.0025
Equivalent µg/dncm @ 68 ^{o}F and 3% O_2	0.68	0.23
	-- OR --	-- OR --
Mercury control, % inlet to outlet of ESP	85%	95%

Baseline mercury emissions at Salem Harbor where found to be below the proposed October 1, 2006 limit in only one of three Ontario Hydro tests conducted. However, two of three Ontario Hydro tests met the alternative criteria of 85% removal. The removals in the three runs were

83.7%, 94.5%, and 94.8%. The average removal of 91% met the 2006 limit. During the ACI tests the elemental mercury detection limit alone on the Ontario Hydro runs was enough to fail the 2012 standard. In these runs no particulate or elemental mercury was detected, and the detection limits are summed to obtain the total calculated emission rate. Removal efficiency almost meets the 95% criteria at 94.1%. This removal efficiency is based largely on detection limits rather than measured values, and so may be misleading. To obtain the ultra-low emission required by the 2012 emission limit, ACI would be required. As seen on Figure 16, typical outlet emissions with ACI are below the 0.23 μg/dncm emission limit.

HCl and Ammonia measurements

Four Method 26 runs were made during the baseline, and three during the long-term tests. These tests were conducted at the ESP inlet and were analyzed during baseline for HCl and during the long-term tests for HCl and ammonia. The sulfuric acid used in the Method 26 sample train captures ammonia and can be analyzed. HCl ranged from 5.3 to 11.8 ppmv @ 7% O_2, with a baseline average of 8.1 ppm and long-term average of 6.8 ppm. The fuel chlorine content during the baseline and long-term tests is compared with these results in the section "Coal and Waste Characterization". Ammonia results from the long-term tests showed low levels of ammonia slip, under 0.5 ppmv @ 7% O_2 on average.

Multi-Metals Test Results (Method 29)

Method 29 was run in triplicate at the ESP inlet and outlet during baseline and long-term tests. The long-term test runs were conducted the day after the Ontario-Hydro tests, at the same condition of 10 lb/MMacf carbon injection. The average results of the triplicate runs, as well as calculated percentage removal of each metal across the ESP, are presented in Table 8. The collection of these metals by the ESP does not appear to be dramatically affected by ACI.

Table 8. Method 29 Results from Salem Harbor Unit 1 with and without Sorbent Injection. Average of three runs; all results are reported in µg/dscf (68 °F, actual flue gas O_2)

	Baseline			Long-Term		
	ESP Inlet	ESP Outlet	*Percent Removal*	ESP Inlet	ESP Outlet	*Percent Removal*
Aluminum	13,838	38	***99.7***	13,348	< 14	***99.9***
Antimony	< 1.81	< 0.01	***99.4***	< 2.99	< 0.05	***98.3***
Arsenic	6.23	0.09	***98.6***	< 5.83	< 0.03	***99.5***
Barium	180	0.80	***99.6***	< 196	< 0.34	***99.8***
Beryllium	< 0.79	< 0.00	***100.0***	< 1.10	< 0.01	***99.1***
Boron	65	36	***44.7***	67	< 42	***37.4***
Cadmium	0.44	< 0.02	***95.5***	< 0.46	< 0.01	***97.8***
Chromium	16	0.32	***98.0***	< 16	< 0.13	***99.2***
Cobalt	3.59	0.02	***99.4***	< 3.88	< 0.01	***99.7***
Copper	< 13	< 0.09	***99.3***	< 14	< 0.08	***99.4***
Lead	5.40	0.04	***99.3***	5.84	< 0.03	***99.5***
Manganese	61	0.73	***98.8***	34	< 0.34	***99.0***
Nickel	14	0.28	***98.0***	13	< 0.11	***99.2***
Phosphorous	200	1.76	***99.1***	124	1.28	***99.0***
Selenium	11.78	0.80	***93.2***	10.32	< 0.19	***98.2***
Silver	< 0.15	0.01	***93.3***	< 0.54	< 0.02	***96.3***
Thallium	< 0.42	< 0.00	***100.0***	< 1.35	< 0.04	***97.0***
Tin	1.01	0.39	***61.4***	2.59	1.15	***55.6***
Vanadium	43	0.23	***99.5***	< 44	< 0.09	***99.8***
Zinc	24	0.59	***97.5***	26	< 0.41	***98.4***

Note: "<" indicates that the metal was not detected in at least one of the three runs.

ESP Performance

ESP power levels were recorded during both baseline and long-term tests. These results have been graphed by field (A through G, in the direction of gas flow) for the 8-transformer-rectifier sets that power the ESP. The graphs are shown in Appendix E.

The graphs of the secondary voltage and current spark rate reflect typical performance of an ESP. The current is lowest in the front section due to space charge effects because this section experiences the highest particle loading of all the ESP fields. As the particles are collected in the ESP, these effects are reduced resulting in increasing current levels in the downstream sections.

There are three potential impacts of the carbon injection on ESP performance:

- reduced secondary current in the inlet fields due to corona suppression by the increased particle loading.
- increased or decreased ESP power due to a change in particle resistivity.
- increased reentrainment due to the low hold power on the low-resistivity activated carbon.

The addition of activated carbon to the flue gas would represent only a 1-2% increase in particle loading so it is not likely that this would produce any significant change in the electrical operation of the inlet field. This is reflected from the data on Console 1-A, which shows little change in secondary current. If anything, the current shows a slight increase, which is probably due to some other factor.

Any impact on resistivity would be unexpected, but would be reflected in the power levels in the downstream electrical fields. The data from these fields shows some drop in power in the B and C fields. However, this is probable due to some other factor because the power increases in fields D through H.

Increased reentrainment would also not be expected because the increase of 1-2% carbon would not be a significant increase because the baseline ash already contained up to 30% unburned carbon. Reentrainment would not cause any change in electrical performance of the ESP but could be detected from an increase in opacity. However, there was no increase in particulate emissions during the long-term tests.

COAL AND ASH CHARACTERIZATION

Reaction Engineering managed the fly ash and coal sample analyses during this program. The full report from Dr. Connie Senior of Reaction Engineering is included in Appendix F, with highlights presented here. Most measurements were carried out by Microbeam Technologies except the leaching analyses, which were supervised by Dave Hassett at the University of North Dakota EERC. Salem Harbor personnel performed LOI analyses on site to calibrate the CAMRAC LOI monitor.

Coal and ash samples were collected daily during the baseline, parametric and long-term tests. Salem Harbor fires low sulfur bituminous coals, with the typical specification as shown in Table 1 of this report. A coal was test-fired in the same period as these mercury control tests; South American coal (Drummond) was fired during the parametric tests. The two coals ("standard" and "Drummond") are discussed separately where appropriate, as some differences in characteristics are noted. The standard coal was fired during the baseline test weeks (9/16-9/27) and the long-term tests (11/16-11/22); Drummond coal was fired during the parametric tests (10/7-10/19).

Ultimate, proximate, Hg and Cl analyses were performed on coal samples collected during testing. The main coal samples analyzed were of the standard coal fired during baseline and long-term tests, for comparison of normal operation to low-mercury operation. Some samples of Drummond coal were selectively analyzed. The range of results from the coal analyses is shown in Table 9.

Table 9. Coal Analyses Summary for Salem Harbor

Sample Dates	Baseline Testing 9/23-9/26/2002	Parametric* 10/9/2002	Long-Term Testing 11/19-11/22/2002
ULTIMATE ANALYSIS (As Received):			
Carbon	70.3 - 73.8	69.0	71.4 - 73.8
Hydrogen	4.6 – 5.4	4.5	4.5 - 4.7
Oxygen	6.3 - 13.9	9.8	7.0 - 8.6
Nitrogen	1.3 – 1.4	1.3	1.3 - 1.5
Sulfur	0.6 – 0.8	0.6	0.6 - 0.7
Ash	4.8 – 6.5	4.2	3.2 - 6.1
Moisture	6.8 – 9.1	10.6	7.7 -10.2
Hg, µg/g	0.04 – 0.16	0.06	0.04 - 0.07
Cl, µg/g	78 - 150	21-23	47 - 600
HHV, BTU/lb	12,420 - 12,843	12,114	12,510 - 12,901
SO_2, lb/Mbtu	0.9 - 1.3	0.9	0.9 - 1.0
Ash, lb/Mbtu	3.7 - 5.2	3.4	2.5 - 4.8
Hg, lb/Tbtu	5.1 - 5.6	4.5	3.4 - 5.3
Hg,µg/dnm^3(3%O_2)	6.9 - 7.8	6.3	4.8 - 7.3
PROXIMATE ANALYSIS (As Received):			
Fixed Carbon	43.8 - 50.0	49	52.1 - 54
Volatile matter	35.4 - 44.7	36	32.4 - 36
Ash	4.8 - 6.5	4.2	3.2 - 6.1
Moisture	6.8 - 9.1	10.6	7.7 - 10.2

***** Drummond coal used for parametric tests only

The ash at Salem Harbor Station is of particular interest because of its high degree of effectiveness as a mercury control sorbent under normal operating conditions on Unit 1. Because of this, detailed laboratory analyses were conducted on the ash in an effort to understand the mercury control phenomenon. Selected fly ash samples were analyzed for Hg, LOI, ammonia, Cl, trace metals, particle size distribution, surface area, pore size distribution, and leaching characteristics.

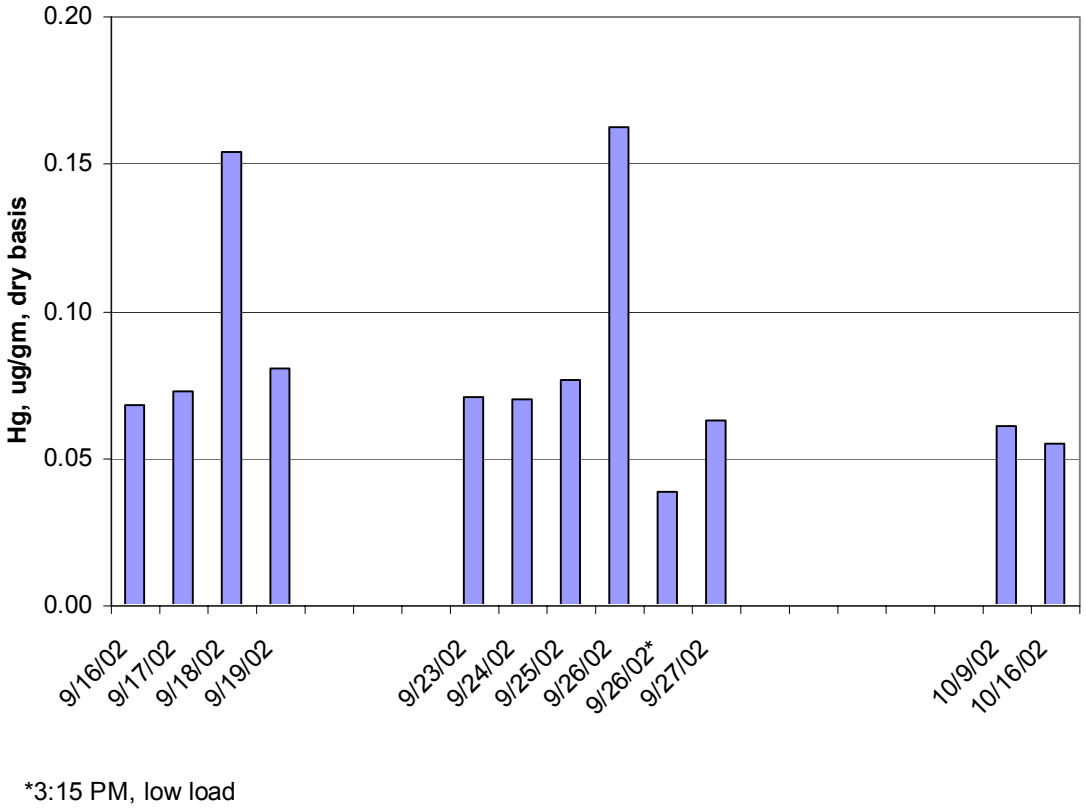
Ash samples were taken from the ESP hoppers. ESP rows labeled A through D correspond to fields that go from the front to the back of the ESP. The A and B Rows are typical of the bulk ash. Comparatively less material is collected in the C and D Rows. From the pre-baseline testing at Salem Harbor in 2001, we know that the C and D Rows contain more large, high-carbon particles, which may be due to particle re-entrainment from the front fields. Extensive ash analyses were performed to evaluate trends in ash characteristics and their distribution within the ESP as various operational parameters changed.

The detailed results from all coal and ash analyses are presented in Appendix F. The highlights and major conclusions are provided in this section.

Coal and Ash Mercury Results

Coal analyses showed some occasional spiking of mercury level by a factor of two. Typical mercury content of the coal corresponds to 0.05-0.08 µg/g, or 5-8 µg/dncm in the flue gas. However two samples indicated 15-16 µg/dncm, a higher level that was also tracked in some S-CEM measurements. Coal samples showed fair comparison with the Ontario Hydro tests performed during both baseline and long-term tests. During baseline tests Ontario Hydro samples taken on three consecutive days ranged from 7 to 14 µg/dncm, averaging 10, while coal analyses indicated 6-7 µg/dncm. The range of scatter in the coal mercury analyses can be seen on Figure 17. During the long-term tests coal mercury samples indicated 5 to 7.5 µg/dncm, while the Ontario-Hydro results showed 5 µg/dncm.

Figure 17. Coal mercury analyses in September and October 2002.



*3:15 PM, low load

During the long-term tests coal mercury increased in the A-Row ash as shown on Figure 18. Mercury in the ash increased from control side levels of ~0.12 µg/g up to as high as ~0.38 µg/g with 10 lb/MMacf ACI. Based on coal analyses, if all the mercury was in the ash, the ash would contain an average of about 1 µg/g mercury. Mercury concentrates towards the rear of the ESP, as shown on Figure 19. Obtaining a representative ash sample for analysis is as always, a challenge when sampling from utility-scale ash hoppers.

Figure 18. Mercury content of A-Row ash for long-term testing, beginning on 11/19/02.

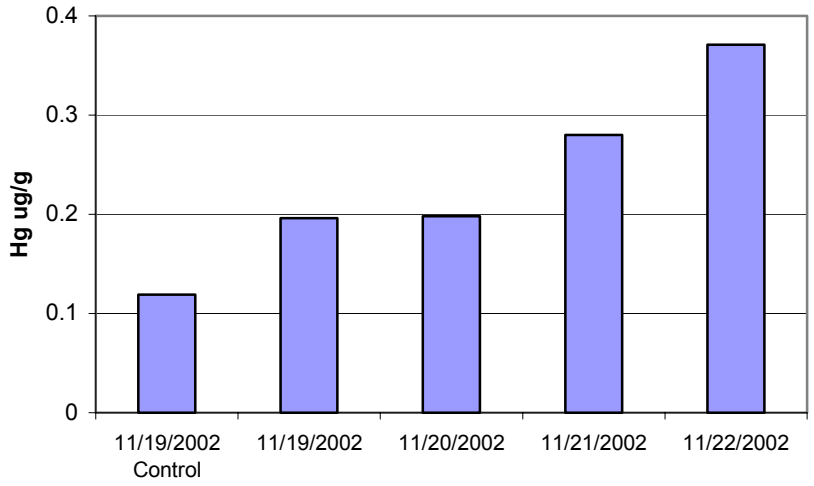
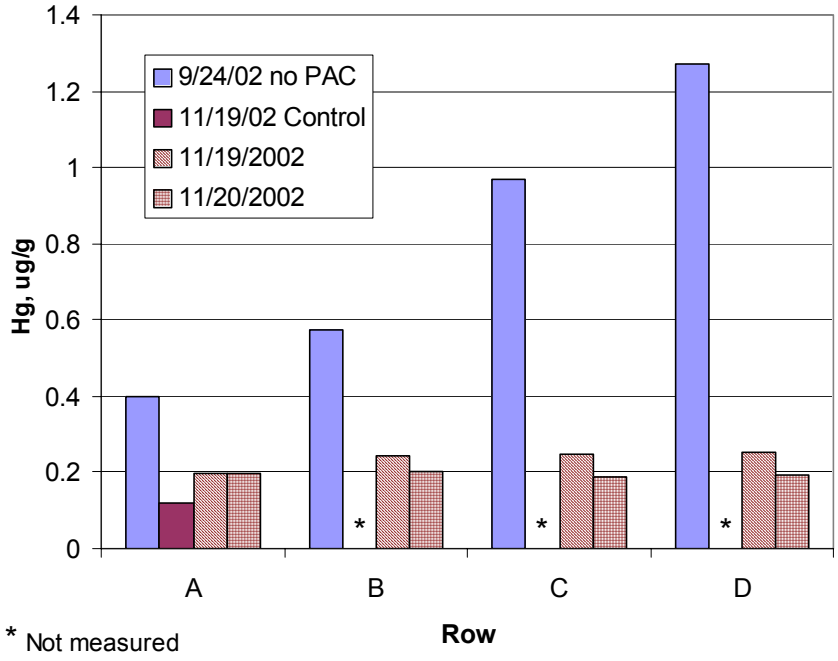


Figure 19. Mercury content as a function of row in ESP for baseline and long-term testing.



Leaching tests were also conducted on the ash samples. The procedures are described here, followed by a summary of the results.

The standard testing technique used for assessing hazardous waste characteristics is the Toxicity Characteristic Leaching Procedure (TCLP, SW846-1311). The test protocol involves exposing a 100-gram sample of ash to 1-liter of acidic solution (acetic acid-or acetate based) for 24 hours. The solution is then analyzed for several metals (including mercury) to determine how much of each target metal was leached from the solid sample. This is an EPA test protocol.[6] Results are compared against limits established by regulation. In the case of mercury, a maximum leachable level of 0.2 mg/liter has been established.

The synthetic ground water leaching procedure (SGLP) was developed at the University of North Dakota Energy and Environmental Research Center (EERC) and was designed to simulate the leaching behavior of CUBs under important environmental conditions.[7] It was initially used to characterize highly alkaline CUBs, primarily fly ash produced from the combustion of low rank coals. The procedure was modeled after the TCLP, but allowing for disposal conditions other than those of a sanitary landfill. Deionized water is used as the leaching solution instead of the acidic solutions used in the TCLP. The SGLP was designed primarily for use with materials such as low-rank coal ash that undergo hydration reactions upon contact with water. Test conditions are end-over-end agitation, a 20:1 liquid to solid ratio and a thirteen-hour equilibration time.

All samples that were leach-tested showed very low levels of mercury leaching, as shown in Table 10. Leaching tests with ACI resulted in the same or less mercury leaching than baseline or control side tests. Comparing the measured values of <0.01 to 0.034 mg/L with the standard of 0.2 mg/L, it is clear that this ash would be acceptable for landfill disposal.

Table 10. Ash Metals and Leaching Analyses for Ash Samples from A Row

									Hg, mg/L	
ADA ID	Date	Ash Sample	Hg, µg/g	LOI, %	As, µg/g	Cd, µg/g	Pb, µg/g	Se, µg/g	TCLP	SGLP
SH00185	11/19/02	Control	0.12	13	12	0.97	23.2	14	0.034	<0.01
SH00070	9/24/02	Baseline	0.4	21	31	2.5	34	50	<0.01	0.016
SH00195	11/20/02	Long-term	0.2	23	0.08	1.00	25.8	37.4	<0.01	<0.01
SH00223	11/22/02	Long-term	0.4	25	0.21	1.68	23	41	<0.01	<0.01

Table 11 shows the % carbon and the BET surface area comparison for samples of pure FGD, a control sample from the control-side ESP's "A" hopper, and a sample from the injection ESP's "A" hopper during long-term tests. The surface area is seen to increase dramatically with injection of FGD, corresponding to effective mercury capture.

Table 11. Sorbent characteristics comparison for Darco FGD, Ash / LOI at Salem, and combined Ash with Darco FGD

	Norit Darco FGD	Ash / LOI Control sample	Ash combined with FGD long-term
% C (LOI)	100	13	23
Surface area, m^2/g	~300	5.7	29

General Results of Coal and Ash Analyses

- Trace metals in the ash did not appear to be significantly affected by ACI.
- Chlorine contents for the standard coal were generally low (50 to 150 μg/g) but there was one outlier on 11/19/02 that had almost 600 μg/g Cl (dry basis). The Drummond coal had lower chlorine (~20 μg/g), based on one sample.
- Chloride, ammonia, LOI and mercury all increased in concentration with ESP row, i.e. the concentrations are greater in the back fields, without ACI.
- Ash Chloride content was affected by temperature. Above 300 ^oF no Cl was detected. At lower temperature of 280-290 ^oF Cl was present in the ash.
- Ash ammonia was higher at 280-290 ^oF than 340 ^oF.
- LOI increased from front to back of the ESP for the standard coal but not for the Drummond coal. There are other variables than coal type between these samples, including flue gas temperature.
- Sorbent injection resulted in an immediate increase in the LOI of the ash in Row A based on a comparison of the control side and test side chambers in the ESP. As the test went on, there was a slight increase in the LOI of the ash in the A Row.
- When compared to the control side of the ESP, the surface area (as calculated from a single-point BET isotherm) increased by about a factor of four when PAC is injected. Unlike the LOI, which increased with row, the surface area did not increase much with row. The high LOI in the back fields of the ESP was therefore presumed to be due to native ash and not to PAC.

ECONOMIC ANALYSIS

After completion of testing and analysis of the data, the requirements and costs for full-scale, permanent commercial implementation of the necessary equipment for mercury control using sorbent injection technology at the 86 MW Salem Harbor Unit 1 were determined. The cost of process equipment sized and designed based on the long-term test results for approximately 80-90% mercury control, and on the plant specific requirements (sorbent storage capacity, plant arrangement, retrofit issues, winterization, controls interface, etc.) have been estimated.

Although high levels of mercury control were achieved at Salem Harbor, the mercury removal by the ash was sensitive to coal type and flue gas temperature. It may also be sensitive to LOI at lower levels; only LOI levels above 15% were examined in this program. Therefore future operating variations that affect the LOI or temperature may adversely impact mercury removal.

Activated carbon injection into the ESP could achieve the removal of 80-90%, as long as flue gas temperatures are maintained below 330 °F, with the design injection rate of 10 lb/MMacf (which corresponds to 210 lb/hr sorbent at Salem Harbor).

The estimated uninstalled cost for a sorbent injection system and storage silo for 80-90% mercury control on the 86 MW Unit 1 is $395,000 ± 10%. Costs were estimated based on a long-term PAC injection concentration of 10 lbs/MMacf. For Salem Harbor Unit 1, this would require an injection rate of nominally 210 lb/hr. Assuming a unit capacity factor of 65% and a delivered cost for PAC of $0.50/lb, the annual sorbent cost for injecting PAC into the existing ESP would be about $570,000. Table 12 summarizes the design criteria used for the pricing for this scenario.

Table 12. System Design Criteria for Mercury Control System at Salem Harbor Unit 1

	80-90% Mercury Capture
Number of Silos	1
Number of injection trains	3: two operating, one spare
Design feed capacity/train	150
Operating feed capacity/train (lb/hr)	105
Sorbent	Powdered Activated Carbon
Aerated Density (lb/ft^3)	18
Settled Density (lb/ft^3)	34
Particle MMD (microns)	18

Sorbent Injection System Description

The description and design data provided in detail here are for the 10 lb/MMacf system targeted at 80-90% mercury control via ESP injection for Salem Harbor Unit 1.

The permanent commercial Activated Carbon Injection (ACI) system would consist of one bulk storage silo and dilute-phase pneumatic conveying systems. ADA has generated a database of cost estimates for this type of system, and has customized this cost estimate to the Salem Harbor Unit 1 ACI system design. The details of the cost workup are included in Appendix G.

PAC sorbent would be received in 40,000 lb batches delivered by self-unloading pneumatic bulk tanker trucks. The silo would be equipped with a pulse jet type bin vent filter to contain dust during the loading process. The silo would be a shop-built, dry-welded tank with twin mass flow discharge cones equipped with air fluidizing pads and nozzles to promote powder flow. Point level probes and weigh cells monitor sorbent level and inventory.

The PAC would be fed from the discharge cones by rotary valves into feeder hoppers. From the hoppers the PAC is metered into the conveying lines by volumetric feeders. Conveying air supplied by regenerative blowers passes thru a venturi eductor, which provides suction to draw the PAC into the conveying piping and carry it to distribution manifolds, where it splits equally to multiple injection lances into the two ESP inlet ducts. The blowers and feeder trains would be contained beneath the silo within the skirted enclosure.

A programmable Logic Controller (PLC) would be used to control all aspects of system operation. The PLC and other control components will be mounted in a NEMA4 control panel. The control panel, MCCs and disconnects would be housed in a pre-fabricated power and control building located adjacent to the silos.

Balance of Plant Requirements

Some modifications and upgrades to the existing plant equipment would be required to accommodate the ACI system. These include upgrades to the electrical supply at Salem Harbor to provide new service to the ACI system. Instrument air, intercom phones and area lighting would also be required.

Cost and Economic Methodology

Costs for the Sorbent storage and injection equipment were provided by Norit-Americas (Norit) based on the design data in Table 12. Norit has built and installed dozens of similar systems at waste-to-energy and incineration plants. ADA provided costs for the distribution manifold, piping and injection lances. Norit also provided an installation man-hour estimate and crane-hour estimate that were used to develop the installation costs for the Norit Equipment along with an estimate for foundations including pilings.

EPRI TAG methodology was used to determine the indirect costs. A project contingency of 15% was used. Since the technology is relatively simple and well-proven on similar scale, the process contingency was set at 5%. ACI equipment can be installed in a few months, therefore no adjustment was made for interest during construction, a significant cost factor for large construction projects lasting several years.

Operating costs include sorbent costs, electric power, operating labor, maintenance (labor and materials) and spare parts. An average incremental operating labor requirement of 6 hours per day was estimated to cover the incremental labor to operate and monitor the ACI system. The annual maintenance costs were based on 5% of the uninstalled equipment cost.

No provision was made for impacts to ash disposal costs at Salem Harbor.

More detailed cost information in all categories, including labor rate assumptions, etc., are included in Appendix G.

Capital Costs

Assuming 80-90% target control of mercury, the uninstalled ACI storage and feed equipment costs are estimated at $395,000± 10%. The estimated cost for a sorbent injection system and storage silo installed on the 86 MW Unit 1 is $946,260, including all process equipment, foundations, support steel, plant modifications, utility interfaces, engineering, taxes, overhead and contingencies. Table 13 briefly summarizes the estimated capital and O&M costs.

Table 13. Capital and Operating & Maintenance Cost Estimate Summary for ACI System on Salem Harbor Unit 1. Annual Basis 2003

CAPITAL COSTS SUMMARY	
	80-90% η
Equipment, FOB Pleasant Prairie	$395,000
Site Integration (materials & labor)	$120,000
Installation (ACI silo and process equipment, foundations)	$130,000
Taxes	$30,900
Indirects/Contingencies	$270,360
Total Capital Required	**$946,260**
OPERATING & MAINTENANCE COSTS SUMMARY	
Sorbent @ $.50/lb	$569,400
Other miscellaneous costs	$102,568[1]
Waste Disposal (including lost revenue)	--
Annual O&M for 2003	**$671,968**

[1] Assuming normal labor rates; may need adjustment upward for tight labor market.

Operating Costs

The most significant operational cost of ACI for Salem Harbor is the PAC sorbent. Sorbent costs were estimated for nominally 80-90% mercury control based on the long-term PAC injection concentration of 10 lbs/MMacf, using $0.50/lb as a sorbent cost. For Salem Harbor Unit 1, this would require an injection rate of nominally 210 lb/hr. Assuming a unit capacity factor of 65% and a delivered cost of $0.50/lb for PAC, the annual sorbent cost for injecting PAC into the existing ESP would be about $570k. Waste disposal costs are not considered since the ash at Salem Harbor is currently landfilled, and this would not change. Other annual operating costs including electric power, operating labor, and maintenance are estimated at about $103k per year.

CONCLUSIONS and RECOMMENDATIONS

A full-scale evaluation of mercury control using activated carbon injection upstream of a cold-side ESP on a low-sulfur bituminous coal was conducted at PG&E NEG's Salem Harbor Unit 1. This comprehensive test program answered many questions about the potential for mercury control via activated carbon injection at Salem Harbor, and also pointed to several areas in which more information is needed. This section summarizes the test results and conclusions, as well as some recommendations for implementation of a permanent mercury control system for the unit, should this be deemed necessary.

Results and trends from these relatively short-term tests were encouraging, reinforcing ACI as a solution for mercury control if process conditions change such that baseline removal is impaired.

- The native removal of mercury under normal operating conditions ranged from 80-95%. Coal mercury is typically in the range of 5-8 µg/dncm, but occasionally spikes to twice this level.
- Baseline mercury emissions at Salem Harbor ranged from ~0.3 to 1.3 µg/dncm, typically. This corresponds to about 0.0033 to 0.0145 lb/GW-hr. In a one-week test, ACI resulted in emissions of 0.0026 to 0.0036 lb/GW-hr via Ontario Hydro, which is at the Ontario Hydro detection limit for both particulate and elemental mercury.
- Comparing emissions rates to the MA proposed 310 CMR 7.29 limits, the near-term target of 85% removal could be met if all process conditions stay the same. The standard of 0.0075 lb/GW-hr, effective October 1, 2006, corresponds to about 0.68 µg/dncm, a level which was not met during baseline testing.
- The more stringent limit of 0.0025 lb/GW-hr or 95% control, effective October 1, 2012, corresponds to about 0.23 µg/dncm and was met during the bulk of ACI testing. This was shown by the S-CEM, which has a lower detection limit than Ontario Hydro. The Ontario Hydro results, just based on detection limits and not measured values, cannot demonstrate this low emission rate.
- A test method with a lower detection limit than Ontario Hydro would be required to consistently demonstrate compliance at 0.0025 lb/GW-hr, which corresponds to about 0.23 µg/dncm flue gas mercury emissions. The sorbent trap test method, now proposed as EPA Draft Method 324, could meet the lower detection requirements.
- The native removal of mercury drops as temperature is increased, with removal starting to fall off above 320°F and dropping dramatically at temperatures greater than 340°F.
- The extremely low residual emissions at Salem Harbor could result in difficulties with demonstrating significant further reductions in mercury emissions. Test method detection limits are already challenged by the low emissions.
- LOI reduction in the range tested did not affect mercury removal. LOI was reduced from about 35% to about 17% with no affect on mercury control.

- The urea-based SNCR system was tested (on/off) for any impact on mercury removal; none was indicated.
- Under normal operating conditions, activated carbon had a small affect on overall mercury capture, which was already very high.
- Activated carbon injection successfully removed vapor-phase mercury at temperatures under 330°F. When flue gas temperature is increased above 340 F, the effectiveness of PAC is significantly reduced.
- At about 10 lb/MMacf, or 210 lb/hr sorbent injection, incremental removal of about 35 to 60% could be obtained over the native removal. This resulted in continuous overall mercury capture of 85-95% as demonstrated by SCEM measurements in a four-day test at flue gas temperature of about 325°F.
- Multi-metals tests did not indicate any significant affect on metals capture in the ESP with sorbent injection.
- The installed capital cost of an ACI system for Salem Harbor Unit 1 is estimated at $946,260 (±10%).
- The annual sorbent cost to obtain consistent removal of 80-90% (using 10 lb/MMacf PAC injection into the ESP) is $570,000 (in 2003 dollars).

REFERENCES

1. Brown, T.D., D.N. Smith, R.A. Hargis and W.J. O'Dowd. "Mercury Measurement and Its Control: What We Know, Have Learned, and Need to Further Investigate," *J. Air & Waste Management Association*, pp. 1-97, June 1999.

2. U.S. DOE Cooperative Agreement No. DE-FC26-00NT41005.

3. Durham, M.D., C.J. Bustard, R. Schlager, C. Martin, S. Johnson and S. Renninger. "Field Test Program to Develop Comprehensive Design, Operating and Cost Data for Mercury Control Systems on Non-Scrubbed Coal-Fired Boilers". Presented at the Air & Waste Management Association 2001 Annual Conference and Exhibition, June 24-28, 2001, Orlando, FL.

4. Durham, M.D., C.J. Bustard, R. Schlager, C. Martin, S. Johnson and S. Renninger. "Controlling Mercury Emissions from Coal-Fired Utility Boilers: A Field Test" *EM, Air & Waste Management Association's Magazine for Environmental Managers,* pp 27 – 33, July 2001.

5. Sjostrom, S., T. Ebner, T. Ley, R. Slye, C. Richardson, T. Machalek, R. Richardson, R. Chang and F. Meserole. "Assessing Sorbents for Mercury Control in Coal-Combustion Flue Gas". Presented at the "A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control," Chicago, IL, August 21 –23, 2001.

6. U.S. EPA. "Toxicity Characteristic Leaching Procedure," Federal Register, Vol.55, No., 61, pp. 11798-11877, March 1990.

7. Hassett, D.J. "A Generic Test of Leachability: The Synthetic Groundwater Leaching Method," North Dakota Mining and Mineral Resources Research Institute, Grand Forks, North Dakota, 1987.

APPENDIX A

TEST PLAN

DOE NATIONAL ENERGY TECHNOLOGY LABORATORY MERCURY FIELD EVALUATION

PG&E NEG Salem Harbor Power Plant
Sorbent Injection into Cold-Side ESP for Mercury Control

Test Plan Prepared for:
PG&E NEG
DOE NETL
EPRI

Test Plan Prepared by:
ADA-ES

September 3, 2002

Test conditions noted herein are subject to approval by MA DEP

This document contains confidential information
that is not to be disclosed outside the NETL Salem Harbor Mercury Team

PROJECT OBJECTIVES

The overall objective of this project is to determine the cost and impacts of sorbent injection into the cold side ESP for mercury control at PG&E NEG Salem Harbor Power Plant Unit 1. This unit has very high native mercury removal. Impacts of process variables on native removal of mercury will also be evaluated. The evaluation will be conducted on ½ of the Unit 1 gas stream, nominally 42 MW.

PROJECT OVERVIEW

This test is part of an overall program funded by the Department of Energy's National Energy Technology Laboratory (NETL) to obtain the necessary information to assess the costs of controlling mercury from coal-fired utility plants. The economics will be developed based on various levels of mercury control at four different host sites. The four sites, shown below, burn coal and have particulate control equipment that are representative of 75% of the U.S. coal-fired generation.

Test Site	Coal	Particulate Control
PG&E NEG Salem Harbor	Low S. Bituminous	Cold Side ESP
PG&E NEG Brayton Point	Low S. Bituminous	Cold Side ESP
Wisconsin Electric Pleasant Prairie	PRB	Cold Side ESP
Alabama Power Gaston	Low S. Bituminous	Hot Side ESP COHPAC FF

Salem Harbor Unit 1 was chosen for this evaluation because of its combination of firing low sulfur bituminous coal with urea-based SNCR, high LOI, and a cold-side ESP. Test results from prior mercury tests have indicated 87 to 94% mercury removal efficiency on this unit, and a better understanding of the source of the high removal rates is desired. The site provides unique challenges that must be evaluated to determine the true impacts of process variables and of sorbent injection. Operating conditions will be modified to temporarily improve or reduce the mercury removal, in order to understand how to optimize the performance in terms of both mercury capture and emissions compliance (for NO_x and particulate matter). While these tests are conducted some operating conditions that are not typical of plant operation will be requested. This will be done during short-term tests (the parametric series). Following the parametric series will be longer-term tests (the long-term series) that will more thoroughly evaluate the operational impacts, costs at reasonable injection rates, and transferability of these operating conditions and results to other coal-fired utility units.

Salem Harbor Unit 1 has unique conditions that are important to this program. They include:

1. PG&E NEG is currently evaluating mercury control options to meet new state compliance regulations in 2006. Sorbent injection is one of the viable options for mercury control.
2. Control rules are likely to be based on improvement over baseline performance, and thus an understanding of how to obtain further removal (above the ~90% removal efficiency baseline) is essential.
3. Salem Harbor utilizes a urea-based SNCR to help reduce NOx emissions. The opportunity to quantify the impact of SNCR on mercury removal and sorbent effectiveness is unique.
4. Modification of process variables such as temperature, LOI, and SNCR will provide some insight into the main contributors to the high mercury removal. These results should allow applicability of the data to other sites with similar process conditions.
5. Three test locations will be utilized for mercury measurements: economizer exit, ESP inlet, and stack. Using all locations will allow tests to be targeted specifically at measuring in-flight mercury capture vs. in-ESP capture.

General Technical Approach

Testing at Salem Harbor is part of a field evaluation program that will implement sorbent injection mercury control technology on portions of full-scale particulate control equipment to obtain performance and operational data, and to gather samples that will help determine the impact of the sorbents on waste disposal and byproduct reuse.

A series of parametric tests will be conducted to determine the optimum operating conditions for several levels of mercury control. In the case of Salem Harbor, two major objectives are the drivers. The primary objective is to find out whether sorbent injection can enhance mercury removal beyond the baseline removal by flyash. The secondary objective is to better understand the cause of the high mercury removal baseline, this will be accomplished by varying process conditions. Variables that may contribute to the high removals include low ESP operating temperatures, high LOI/carbon content of the ash, and the operation of SNCR. Modifying one or more of these variables may result in a temporary decrease in control of mercury, NO_x, or particulate matter.

During sorbent injection, only the benchmark sorbent, Norit America's Darco FGD, will be injected. The native ash at Salem Harbor is viewed as a second sorbent, since this ash already is proven to have close to 90% removal. Therefore tests will address both the injected sorbent, Darco FGD, and operating conditions that may influence the native ash. The maximum (Darco FGD) sorbent injection rate will be set based on practical limitations of ESP performance, measurable mercury removal, and cost. Based on results from these tests, a two-week test with activated carbon and optimized conditions will be conducted to assess longer-term impacts to the ESP, ash and auxiliary equipment operation. To save costs during optimization, mercury levels will be measured with a semi-continuous emissions monitor (S-CEM). During the long-term test the S-CEM and mercury removal efficiencies will be verified by Ontario Hydro method measurements.

The economic analysis will include:

- Capital costs
- Waste disposal issues
- Sorbent usage costs
- Byproduct utilization issues
- Impact on ESP operation
- Enhancements, such as cooling
- Balance of plant
- O&M requirements

Pre-baseline tests were performed in February 2001. Injection equipment will be installed in August 2002. During the second week of September 2002, Unit 1 is scheduled for an outage, during which injection ports for the sorbent will be installed. All equipment will be ready for startup by September 16, 2002. Testing starts the week of September 16, and will continue into November 2002.

SITE DESCRIPTION

PG&E National Energy Group owns and operates Salem Harbor Station located in Salem, Massachusetts. There are four fossil fuel fired units at the facility designated as Units 1, 2, 3, and 4. Units 1-3 fire a low sulfur, bituminous coal and use oil for startup. Unit 4 fires #6 fuel oil. Unit 1, which is scheduled to be the test unit, is a B&W single-wall-fired unit with twelve DB Riley CCV-90 burners. It is rated at 88 gross MW.

The particulate control equipment consists of a two-chamber, cold-side ESP (chambers designated 1-1 and 1-2), which provides two separate gas flow paths from the outlet of the tubular air heaters to the ID fan inlets. This Environmental Elements ESP has a rigid electrode design and a specific collection area (SCA) of 474 ft2/1000 acfm. The precipitator inlet gas temperature is nominally 255ºF at full load.

There are eight electrical fields in the direction of flow, and two across. The discharge electrodes are 44.5 feet in length and are spaced 18" apart in the direction of gas flow. There is a total of 171,108 square feet of collecting plate surface area.

There are eight precipitator ash hoppers on Unit 1, four in the direction of flow and two across. A pneumatic conveying system ties into each hopper and blows dry ash into the fly ash storage silo, where it is combined with flyash from the ESPs, economizer hoppers, and air preheater hoppers from Units 1, 2 and 3. Both wet and dry unloading systems are available to feed the ash from the fly ash storage silo into a truck.

Typical LOI / carbon content of the Unit 1 ash is about 25%. This ash is landfilled.
A summary of important descriptive parameters for Salem Harbor Unit 1 is presented in Table 1.

Table 1
Site Description Summary, Salem Harbor Unit 1

PARAMETER IDENTIFICATION	DESCRIPTION
Process	
Boiler Manufacturer	B&W 85 MW Radiant Boiler
Burner Type	DB Riley CCV-90
Low NOx Burners	Yes
Steam Coils	**Yes**
Over Fire Air	No
NOx Control (Post Combustion)	SNCR
Temperature (APH Outlet)	255
Coal	
Type	South American Bituminous
Heating Value (Btu/lb)	12701
Moisture (%)	9.64
Sulfur (%)	0.63
Ash (%)	3.92
Hg (μg/g)	0.03
Cl (μg/g)	206
Control Device	
Type	Cold-Side ESP
ESP Manufacturer	Environmental Elements
Design	Cold-Side, Rigid-Electrode
Specific Collection Area (ft^2/1000afcm)	474
Flue Gas Conditioning	None

TECHNICAL APPROACH

Three test locations are planned for mercury measurements on Salem Harbor Unit 1: the APH exit, the ESP inlet, and the ESP outlet (ID fan inlet). All three of these test locations will be utilized during the fall 2002 test program. In February 2001 a pre-baseline series of tests was conducted, and the test matrix described herein is based partly on what was learned during that series.

The pre-baseline tests conducted (via SCEMs measurement method, see Appendix A) in February 2001 confirmed the finding in the earlier ICR measurements, that mercury removal by the ash at Salem Harbor is very high. These pre-baseline tests also showed that the mercury at the ESP inlet is mostly in the vapor phase, which contradicts the ICR result at that location using the Ontario-Hydro method. The SCEMs measures only vapor-phase mercury and is not subject to the Ontario-Hydro method's tendency to artificially indicate higher proportions of particulate-phase mercury. These pre-baseline results also show that oxidation of the vapor-phase mercury occurs between the economizer exit and the ESP inlet (across the air preheater). There is not significant baseline removal of mercury in this zone from the economizer exit to the ESP inlet. Measuring at all available locations during the full-scale test program should quantify the degree of in-flight mercury capture in this zone during sorbent injection tests. Thus measurements are planned at all locations.

The parametric test series at Salem Harbor is unique in its focus on process variables, in addition to injection of sorbent. Other variables of interest are temperature, SNCR on/off, and LOI/carbon in the ash. The feasibility and methodology for controlling these parameters needs to be finalized among the team. Each of them is discussed briefly here. Further details and test conditions are described under Task 5, below.

Sorbent Injection

Sorbent injection will be tested to determine whether further removal beyond the 90% removal measured in baseline conditions is possible. At Salem Harbor just one injected sorbent will be used, the benchmark sorbent, Norit America's Darco FGD. A potential difficulty with these parametric tests is the lower detection limit of the SCEMs (which is similar to the detection limit of the Ontario-Hydro method), this detection level is already challenged by the baseline conditions. However, using test locations at the economizer exit, and the ESP inlet during parametric tests, the team will attempt to quantify in-flight mercury removal between the injection point and the ESP inlet. If mercury removal is seen between the APH outlet and ESP inlet locations, this will be attributed to the injected sorbent, since the ash does not remove significant mercury in this zone. This mercury removal is termed the "in-flight" removal by the sorbent. The approximate range of injected sorbent concentrations will be 5-20 lb/MMacf.

Temperature

The Unit's steam coil will be used to increase the temperature of the flue gas. The current ESP operating temperature is about 255 ºF, which is a low temperature well-suited to mercury capture by sorbent, especially oxidized mercury. Increasing this temperature could provide some insight into the capture conditions, and their applicability to other similar boilers. This temperature should be increased to the maximum feasible(approximately 300 F). The temperature range for

mercury tests will be determined during a pre-test of Unit 1 during the week of September 3, 2002.

SNCR

SNCR is a variable that has not been proven to (or not to) affect mercury capture, and there is some debate in the industry as to its potential effect. The team recognizes that turning off SNCR has serious implications for Salem Harbor's NO_x compliance, and proposes an approach that will provide a clean test of the impact of SNCR, while minimizing the amount of time that SNCR will be turned off.

Testing SNCR's impact on mercury is more complex than just turning off the reagent flow. The residual ammonia on the internal surfaces and in the flyash may continue to affect mercury removal or speciation after SNCR is turned off. Approaches to obtaining a solid test result would be either to leave the urea off for a long period of time, such as several days, or to begin the test series with a "clean unit" test after the outage, prior to turning on urea injection at all. The latter approach is proposed, and enables testing of "baseline" conditions without SNCR. The timing of this is important because given the clean-furnace conditions after startup, the operators will have the maximum opportunity to control NO_x and mitigate the effect of turning off SNCR. Therefore we propose that as soon as possible after startup, when steady, high-load conditions are obtained while burning coal, the SCEMs will be used to obtain "SNCR off" measurements. Since startup involves troubleshooting and shakedown of myriad plant systems, the team requests that two days be allocated after startup with at least six to eight hours of full load operation for "SNCR off" operation, during which measurements will be made of mercury control across the ESP. This reduces the time without SNCR to two days from several days, and provides superior data because there can be no question that residual ammonia is in the system. The proposed approach to obtaining these test conditions is presented in the Field Testing section (Section 5), Table 3.

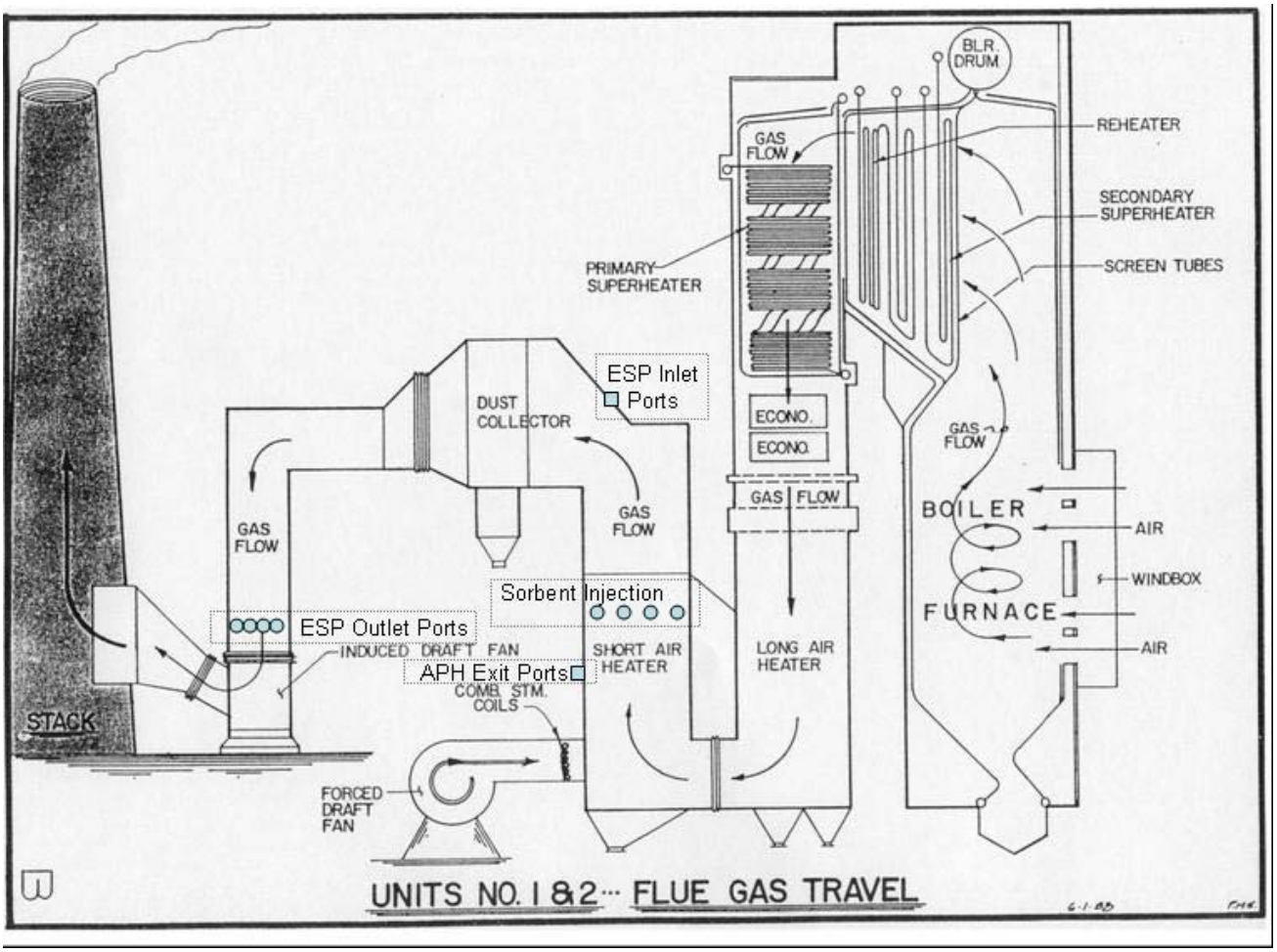
LOI/Carbon

The final process variable, LOI/carbon content in the ash, typically runs about 25%, and appears to be effective for mercury control, similarly to an activated carbon sorbent. Based on data from other sites, it is likely that this variable is a significant contributor to the mercury removal at Salem Harbor. Tests at multiple levels of LOI/carbon would provide valuable information on the correlation with mercury control, and may determine a lower threshold LOI/carbon level for capture. Variables that may be modified to reduce LOI/carbon during a test period include excess air and load. This will involve modifications to unit operation that are not standard and will have (temporary) emission impacts, while maintaining emission limits within permitted levels. LOI/carbon may be a major contributor to mercury removal, and identifying operating conditions that correlate to mercury removal at Salem Harbor would allow operators to make judgments on mercury removal vs. burner operation.

Operating variables that may affect LOI are being tested during the week of September 3 to determine the exact operating conditions and their impact on LOI in the ash. These conditions will then be re-established and held for longer periods during the parametric test series when full mercury measurements will be made. Since pre-testing of unit operating conditions has not yet

taken place, the test conditions (see matrix, Table 3) may be adjusted based on the outcome of these tests.

Figure 1: Plan View of the ESP arrangement at Salem Harbor (Unit 1)



The primary objective of the field evaluation at Salem Harbor will be achieved through eight technical tasks. In the overall program these tasks are numbered 2 through 9. The tasks are identified in the following flow chart.

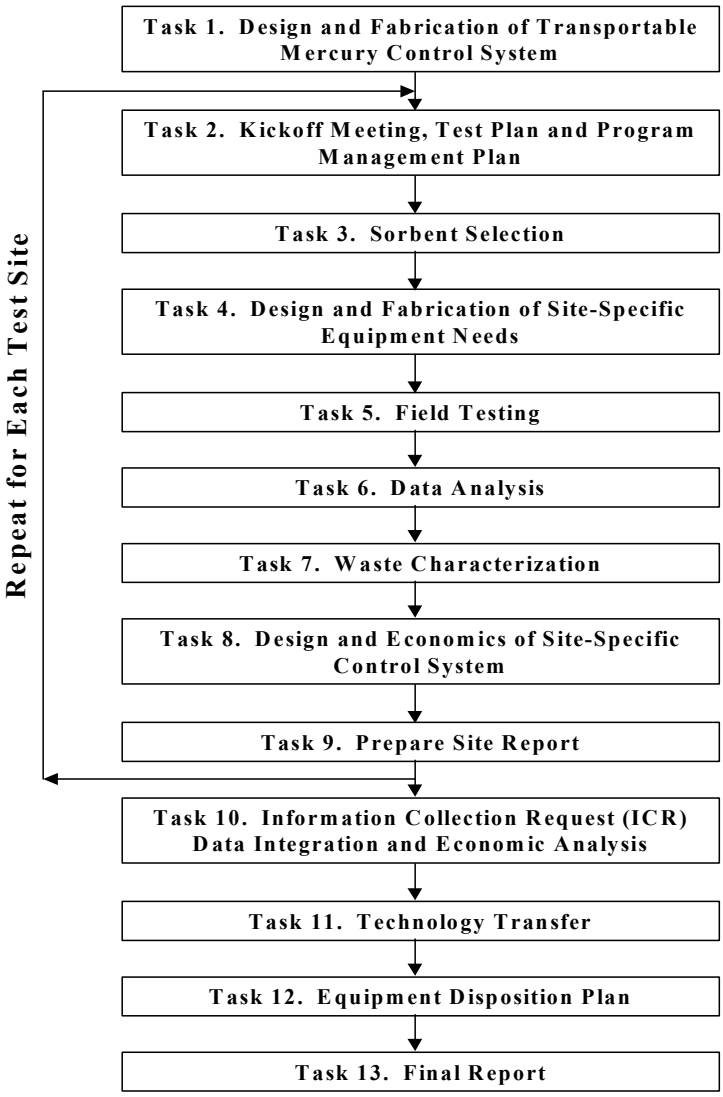
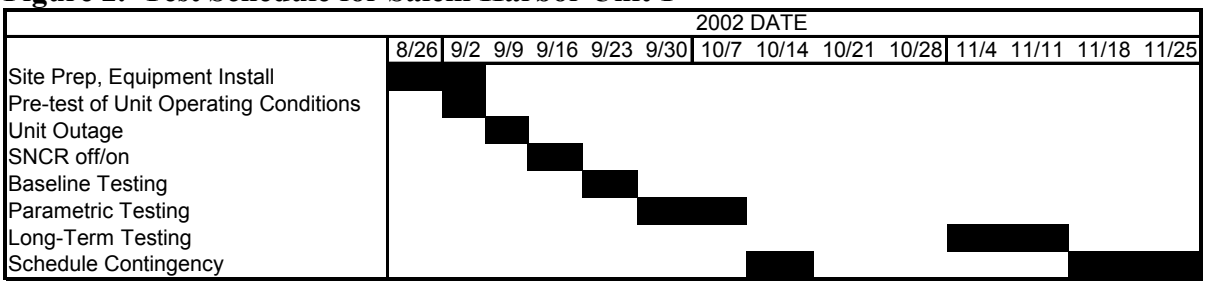


Figure 2 presents the schedule for the field test portion of the Salem Harbor program. Figure 2 shows that field testing should be completed in November 2002.

Figure 2. Test Schedule for Salem Harbor Unit 1



Task 2 – Kickoff Meeting and Test Matrix

Engineering personnel at Salem Harbor have met with ADA-ES personnel to coordinate the details of the Salem Harbor equipment and test program. On July 16, 2002 a site visit initiated discussion on the schedule and test parameters. The overall scope of the program, the potential impact on plant equipment and operation, environmental permitting issues and site-specific goals were discussed.

This document provides detailed breakdown of the test matrix including the expected settings for the parametric tests, a list of samples and test procedures, a task schedule and sampling QA protocol. The detailed test results from Sorbent Screening tests are omitted from this Test Plan since the Salem Harbor testing will focus on several process variables, and multiple sorbents will not be tested because baseline removals are so high. Please refer to the Test Plan for Brayton Point Power Plant (April 2002) for information on Sorbent Screening tests.

Task 3 – Sorbent Selection

The high baseline mercury removals of 87-94% at Salem Harbor Unit 1 make it of great interest to understand which operating conditions are the main contributors. Coal mercury levels are already low at this site, providing about 3-4 ug/Nm3 of mercury in the flue gas, and so little is left at the stack that it cannot be measured accurately without the use of the complex, time-consuming, and expensive Ontario-Hydro method. At these low concentrations the SCEMs requires long collection times, greater than one hour. Thus several of the parametric tests will be focused on understanding the already-high removal rates. The benchmark mercury removal sorbent, Norit America's Darco FGD, which has been demonstrated in many bench-scale, pilot-scale and full-scale tests conducted under DOE, EPRI and EPA programs, will be the single additional sorbent tested to determine whether removals can be pushed beyond baseline levels.

Task 4 – Design and Fabrication of Site-Specific Equipment Needs

The mercury control process equipment for the Salem Harbor Power Plant is smaller than that in use at Brayton Point. ADA-ES' Portapack system can be used for the smaller gas volumes and low mercury concentration. This will allow quick setup during August. The objective is to have all equipment fully installed and operational by September 16, 2002. Equipment will be installed and mercury will be measured on one-half of Unit 1, nominally 42 MW.

Sorbent Injection System

The sorbent injection equipment is a skid-mounted, portable, dilute-phase pneumatic system. The activated carbon will be delivered to the plant in 900 lb supersacks which will be stored on pallets adjacent to the injection skid. Project personnel will load individual supersacks onto the injection skid by a hoist. The reagent is metered by a variable speed screw feeder into an eductor that provides the motive force to carry the reagent to the injection point. A PD blower provides the conveying air. A PLC system is used to control system operation and adjust injection rates.

Flexible hose will carry the reagent from the feeder to a distribution manifold that will be located across the ESP inlet duct(s) feeding the four injection probes.

ADA-ES will work with the station and its installation subcontractors to provide all required information for system installation and operation. This will include a drawing package of the ADA-ES supplied equipment and installation requirements, as well as criteria and specifications for Balance of Plant (BOP) equipment and materials provided by others. ADA-ES will also provide a list of utility requirements (electric power, water, and compressed air) for the injection system and SCEMs. Responsibility for procurement of the sorbent injection system is divided between ADA-ES and PG&E as shown in Table 2.

Two different styles of lances have been tested at Brayton Point aimed at improving distribution. It appears as though there is very little difference in performance between the two different style lances. At Salem Harbor a single lance design will be used. The relatively small duct should provide good distribution of sorbent.

Table 2. Scope Split for Sorbent Injection System

ADA-ES Transportable System	Provided by Host Site
Sorbent Injection System	Injection ports
Sorbent Distribution Manifolds	Test ports
Conveying Hose (400 ft)	Access platforms
Sorbent Injectors	Installation labor/Materials
PLC Controls	Compressed air
Hg SCEMs	480V Power
Office Trailer(s)	Signal Wiring / Telephones

Task 5 – Field Testing

The field tests will be accomplished through a series of nine (9) subtasks. The subtasks are independent from each other in that they each have specific goals and tests associated with them. However, they are also interdependent, with the results from each task influencing the test parameters of subsequent tasks.

An overview of the proposed full-scale tests is shown in Table 3. The various tests are described below in their corresponding Subtask. Exact operating conditions are subject to change based on the short testing being conducted the week of September 3. The results from these tests will more clearly define operation during parametric testing.

Subtask 5.1 – Pre-Baseline Measurements
These tests were conducted February 13-21, 2001 at Salem Harbor on Units #1 and #3. Using a vapor phase mercury Semi-Continuous Emissions Monitor (S-CEM) supplied by Apogee Scientific, mercury measurements were taken at three different locations per unit. Results indicated that a majority of the mercury was captured in the ESP. These results were documented in a memo issued on March 9, 2001, included here as Appendix B.

Subtask 5.2 – Sorbent Screening

This task was not performed separately for Salem Harbor tests. Please refer to Brayton Point Test Plan (April 2002).

Subtask 5.3 – Site Modifications, Equipment Installation and System Checkout
ADA-ES will oversee installation and checkout of the mercury control equipment. The mercury control process equipment has been fabricated and will be delivered to the Salem Harbor in August. The objective is to have the equipment fully installed and operational by September 16, 2002. Injection equipment will be installed on one-half of Unit 1's gas flow.

The plant and its installation subcontractors will install the equipment including any forklift or crane support. This will include anchoring of the injection skid, running and supporting the flex hose, mounting the injection manifold, providing and terminating electric power and compressed air to the injection skid.

Measurement equipment (SCEMs) provided by Apogee will be installed at three locations: the APH exit, the ESP inlet, and the ESP outlet (ID fan inlet). This equipment will require power provided by the plant. All sampling ports should be cleaned of buildup prior to testing.

Subtask 5.4 – QA/QC Plan
Subcontractors will be performing the various sampling and analytical functions required to evaluate the effectiveness of the mercury controls. QA/QC procedures will be prepared as part of detailed test matrices that will be submitted ahead of testing dates for approvals by PG&E NEG, DOE and EPA. The plans will include the necessary QA/QC activities that are required to assure the validity of collected data. Standard methodologies and procedures have been established for all the methods to be used in the testing, therefore no new or unproved techniques will be introduced to the project. A QA/QA book for test procedures at Salem Harbor will be kept in the test trailer on site.

Appendix C contains a copy of TRC's Quality Assurance Project Plan (QAPP) for testing, including a summary of QA/QC procedures that will be followed.

Table 3 Proposed Full-Scale Test Sequence for Salem Harbor Unit 1

Test Description	Dates	Parameters/Comments	Boiler Load
Operational pre-test	9/3-9/6	Modify temperature and LOI/carbon levels to quantify the limits on these process variables	100%, 70%
SNCR off: From Unit startup for two days, or until steady, high-load conditions are obtained	Startup ~9/16 until ~9/19	Keep SNCR off to keep unit clean of NH3 until baseline measurements are made Day 1 – Startup Day 2 – SCEM with no SNCR Day 3 – SCEM with no SNCR Day 4 – SCEM with SNCR	Startup, Steady load during actual tests (two days)
Baseline Tests (No sorbent injection; normal unit operating conditions) followed by off-normal conditions on Days 4&5	9/23-9/27	Day 1- Ontario Hydro & M29 tests Day 2- Ontario Hydro &M29 tests Day 3- Ontario Hydro & M29 tests Day 4 & 5- Reduce LOI/carbon by detuning burners (increase air, decrease load slightly as needed)	Full Load 24 hours per day
Parametric Week 1 (LOI/carbon and Temperature effect on Hg capture, with and without sorbent injection)	9/30-10/4	Day 1- Increase Temperature with reduced LOI/carbon Day 2- Depending on previous results, change LOI/carbon or Temperature again Day 3- Add sorbent injection at medium rate (8-15 lb/MMacf) to high temperature, low LOI/carbon condition. Day 4- Sorbent injection at high injection rate (10-20 lb/MMacf) with high temperature, low LOI/carbon condition. Day 5 - Contingency	Full Load 6AM-6PM
Parametric Week 2 (Sorbent injection in combination with process variables)	10/7-10/11	Day 1- Low injection rate (1-5 lb/MMacf) with lowest-removal condition tested (LOI/carbon, Temperature variables) Day 2- Low injection rate with normal operation. Day 3- Medium injection rate (8-15 lb/MMacf) with normal op. Day 4- High injection rate (10-20 lb/MMacf) with normal op.	Full Load 6AM-6PM
Long-term tests (Darco FGD injection;	11/4-11/13	Operate at consistent injection rate 24 hours a day while load following.	Full Load only

rate TBD)		Conduct Ontario-Hydro and Method 29 tests during 11/7-11/8 if possible; 11/11 -11/12 are the contingency test days.	during Ontario Hydro

Subtask 5.5 – Startup Week and Baseline Testing
After equipment installation, the unit is scheduled to be on outage until September 16. Table 3 shows the schedule throughout testing. During the startup week (Sept 16-20) SCEMs measurements are planned to document SNCR off and on conditions. The second week after startup (Sept 23-27), baseline tests are scheduled to occur immediately prior to the first parametric test series to best document full load baseline conditions. During this test it is requested that boiler load will be held steady at "full-load" conditions 24 hours per day.

Mercury will be measured using two separate methods:

1) the S-CEM; and
2) standard Ontario Hydro Testing.

A description of the mercury S-CEM can be found in Appendix A.

The Ontario Hydro tests will be conducted by TRC Environmental Corporation. TRC Environmental Corporation will prepare a detailed test plan, complete with QA/QC procedures, prior to testing.

There will be three locations for the S-CEM measurements, and two locations for the Ontario-Hydro measurements. The SCEMs will be at the APH exit, the ESP inlet, and the ESP outlet (ID fan inlet). The Ontario-Hydro will be at the APH exit (just upstream from the sorbent injection ports) and at the ID fan inlet. These locations will allow the maximum information to be obtained on mercury speciation and in-flight capture of mercury by the injected sorbent.

Performance of the ESP is critical to the success of sorbent injection for mercury control. Boiler (Unit 1) operation is important in order to determine that the tests are conducted under obtainable, sustainable operating conditions. The main operating indicators of interest are described here and listed in Table 5.

ESP Performance
Only one chamber will have sorbent injected. The other chamber will be recorded as a "control" chamber for performance comparison during the tests.

Electrical Parameters: Primary and secondary voltage and current, as well as spark rate, will be printed out regularly from existing instrumentation to document any changes in ESP power characteristics.

Flue Gas Temperature: Recorded from plant instrumentation and during any manual traverses.

Rapping Pattern: Any change to the rapping pattern that is required for good performance will be recorded and evaluated.

Opacity/Emissions: Ash resistivity, electrical characteristics, and rapping affect collection efficiency across the ESP. It is not expected emissions will increase with this series of tests, however emissions will be documented by both manual measurements and the site's opacity monitor. Particulate measurements will be made as part of EPA Test Method 29, which will be conducted in conjunction with the Ontario Hydro measurements.

Coal, Ash and Flue Gas Samples

Ash Samples: Fly ash hopper samples will be taken from the ESP hoppers. These ash samples will be analyzed for mercury to compare to in-situ measurements. It is anticipated that samples will be taken during each test condition. Other analyses such as carbon content and composition will be conducted as needed.

LOI/carbon content of the ash will be measured during testing to establish that the unit is at a condition appropriate for the target test. ADA-ES will use a CAMRAC LOI/carbon analyzer for this purpose. Flyash is withdrawn isokinetically from the duct and collected on a filter or sampling cell for analysis. At a prior utility application, sampling limitations were addressed by traversing the duct prior to testing in order to find the regions of highest flow where the LOI was representative of the duct average. Then we left the sampling probe in that location while combustion conditions were changed. The changes in LOI readings were rapid and sensitive to changes in combustion conditions.

Coal Samples: Coal samples will be collected daily. These samples will be analyzed for mercury. Table 4 shows the Ash and Coal Sampling Schedule.

Table 4. Ash and Coal Sampling Schedule

Coal/Ash Sampling Schedule
Hg Field Test - Salem Harbor 2002
Baseline and Parametric Testing Series

Date	Coal					Fly Ash				Sorbent
	Feeders					ESP				Feeder
	1-1	1-2	1-3	1-4	Composite	A- Row	B- Row	C-Row	D-Row	
16-Sep		A				A	A	A	A	
17-Sep		A				A	A	A	A	
18-Sep		A				A	A	A	A	
19-Sep		A				A	A	A	A	
20-Sep										
21-Sep										
22-Sep										
23-Sep	A	A	A			A, 2B	A, B	A, B	A, B	
24-Sep	A	A	A			A, B	A, 2B	A, B	A, B	
25-Sep	A	A	A			A, 2B	A, B	A, B	A, B	
26-Sep		A				A	A	A	A	
27-Sep		A				A	A	A	A	
28-Sep										
29-Sep										
30-Sep		A				A	A	A	A	
1-Oct		A				A	A	A	A	
2-Oct		A				A	A	A	A	2 B
3-Oct		A				A	A	A	A	
4-Oct		A				A	A	A	A	1 B
5-Oct										
6-Oct										
7-Oct		A				A	A	A	A	1 B
8-Oct		A				A	A	A	A	
9-Oct		A				A	A	A	A	
10-Oct		A				A	A	A	A	1 B
11-Oct		A				A	A	A	A	

A - 1 Liter Container
B - 5 Gallon Bucket

Note: Select "control side" ESP hopper samples will be collected during the long-term tests

Unit 1 Operation

System Operation: Boiler load, stack opacity, other stack CEM measurements, flue gas temperatures before and after the ESP, coal source and documentation of operation that may affect the combustion process such as pulverizers that may not be working, etc. Oil flow, soot blowing schedule, APH inlet and outlet temperatures, and other parameters will be recorded. Data will be pulled from the PI operating system where accessible, and will be manually recorded for other parameters.

SNCR Operation: Typical operating parameters such as urea flow rate, ammonia indicated (if available), and NO_x levels will be recorded. Ammonia measurements will be made manually in the economizer exit, across the ESP, and from the ash during selected tests. These measurements may be made on the control side in order to keep the SCEMs in the duct during tests

Table 5 presents data to be collected during baseline, parametric and long term testing. These data will be used to evaluate sorbent injection performance. A data sheet template has been provided to the plant for control room data collection.

Subtask 5.6 and 5.7 – Parametric Test Series 1 and 2: Mercury removal versus plant operational changes and Darco FGD injection rate.

Test conditions during parametric testing will be defined more precisely after conducting pre-testing the week of September 3. the general parameters of interest and targets are described here.

For more background on the individual test parameters and philosophy, please refer to the "Technical Approach" section above, pages 7-9 of this test plan.

The parametric test series is divided into three primary areas of interest:

- Mercury removal enhancement with sorbent injection as a function of injection rate;
- The effect of SNCR on baseline mercury removal performance; and
- The effects of flue gas temperature and ash LOI/carbon with and without sorbent injection.

The sequence of tests is proposed in Table 3 above. The sequence avoids contamination of tests by prior process variables. It begins with "SNCR off" in a clean furnace condition, where operators will have the most ability to control and mitigate any adverse impacts on NO_x. Testing "SNCR off" with no ammonia in the boiler system is important to obtaining a valid test condition. The sequence then tests other process variables prior to beginning injection of carbon, so that no residual carbon will be in the system, possibly interfering with test results.

The ranges of control for LOI/carbon and temperature need to be determined. These tests are important in order to demonstrate the impacts individually of LOI/carbon in the ash as a sorbent, and of the sensitivity of the LOI/carbon to temperature. This information will be very valuable to NEG as future decisions on equipment and operating conditions are made in light of new mercury control requirements. In addition the data will be useful in assessing reasonable and feasible levels of mercury control to other sites with high LOI/carbon.

These parameters (temperature, LOI/carbon) will again be tested with sorbent injection. These tests will provide insight into the interaction between sorbent injection and process variables. Should "baseline" removal drop off with modified operating conditions (lower LOI/carbon or higher temperature), it will be important to learn whether a small amount of sorbent can regain the mercury control. Ideally, the series will lead to an understanding of how much sorbent is needed to correlate to a given LOI/carbon level's mercury removal. This may not be attainable in these few tests, but working towards this goal will help the field team to make decisions on operating conditions as the test series proceeds.

The second week of parametric tests will document mercury removal for three sorbent injection rates conducted at full-load conditions. Tests will be conducted under "normal" boiler operating conditions to determine whether mercury capture by sorbent can enhance the baseline capture by the fly ash.

Table 5 Test Data Collected During Evaluation

PARAMETER	SAMPLE/SIGNAL/TEST	BASELINE	PARAMETRIC/ LONG-TERM
Coal	Batch sample	Yes	Yes
Coal	Plant signals: burn rate (lb/hr) quality (lb/MMBTU, % ash)	Yes	Yes
Fly ash	Batch sample	Yes	Yes
pH of ESP ash	Batch sample	Yes	Yes
Unit operation	Plant Signals: Boiler load Flow rates and temperatures	Yes	Yes
Temperature	Plant signal at economizer outlet, inlet and outlet of ESP	Yes	Yes
Temperature	Full traverse, inlet & outlet	Yes	No/Yes
Duct Gas Velocity	Full traverse, inlet & outlet	Yes	No/Yes
Mercury (total and speciated)	APH exit, inlet and outlet of ESP with S-CEM	Yes	No
Mercury (total and speciated)	Ontario Hydro, inlet and outlet of ESP	Yes (1 set)	No/Yes (1 set)
Ammonia	APH exit, inlet and outlet of ESP (select tests only)	Yes (1 set)	Yes/No
Sorbent Injection Rate	PLC, lbs/min	No	Yes
CEM data (NO_x, O_2, SO_2)	Plant data – stack	Yes	Yes
LOI	LOI monitor, inlet to air preheater	Yes	Yes
Stack Opacity	Plant data	Yes	Yes
SNCR	Plant chart/injection rate, other operating parameters	Yes	Yes
ESP operation	Plant data (ESP electrical, rapping, etc.)	Yes	Yes

The sorbent for these tests will be Norit's Darco FGD. The maximum injection rate predicted is 20 lbs/Mmacf (.5 lbs/MMBtu), but given the low concentration of mercury at Salem Harbor, and the high baseline removals, this may be excessive. The parametric tests, with the SCEM at the ESP inlet location, will attempt to document the level of in-flight mercury removal by the sorbent. Results from these initial low-injection tests will establish reasonable injection rates for the rest of the series. Two lower rates than maximum will be tested in order to trend injection rates with removal efficiencies. Operating and performance parameters to be monitored during this test are listed in Table 5.

DOE may provide (or coordinate with PG&E NEG) for additional sampling during the parametric testing. DOE would primarily be concerned with co-pollutant control measurements of SO3, HF, NOx, HCl, multi-metals and fine particulate matter.

After these tests the test crew will leave the site to analyze data and work with team members on establishing conditions for the long term test. Three weeks are scheduled between the parametric tests and the long term tests, subtask 5.8.

Subtask 5.8 – Long Term Testing
Mercury removal validation testing will be conducted for a maximum of ten days at the "optimum" plant operating conditions and sorbent injection concentration (highest mercury removal at practical cost) as determined from the parametric tests. The project team will obtain concurrence from DOE and PG&E on the test conditions and length of testing. The S-CEM will be used for continuous monitoring of mercury removal. Ontario Hydro measurements at the inlet and outlet will be conducted periodically. A summary of the parameters to be monitored during this test is presented in Table 5. A preliminary report shall be prepared documenting the removal efficiency over time, the effects on the ESP and balance of plant equipment, and operation of the injection equipment to determine the viability and economics of the process.

Task 6 – Data Analysis

Data collected during the field evaluation will be used to prepare a summary report on the effect of sorbent injection on mercury control and the impact on existing pollution control equipment. Various plant signals will be monitored to determine if any correlation exists between changes in mercury concentration and measured plant operating conditions. This analysis will include a characterization of mercury levels and plant operation for baseline conditions, various injection rates, and various temperatures (if determined appropriate). . This analysis will also identify effects of sorbent injection on operation and predict long term impacts.

Coal and fly ash samples will be collected during baseline and long term tests for analysis. Ultimate and proximate analysis and measurements for mercury, chlorine and sulfur of the coal will be conducted. Ash samples will be analyzed for mercury and carbon content. Ash samples will also be analyzed by hopper section to determine if there is mercury segregation across the ESP. Task 7 describes further analyses
A full temperature, velocity, particulate loading and mercury (total and speciated) traverse at the inlet and outlet at full load conditions will be conducted to determine profiles for appropriate sampling and sorbent distribution. The S-CEMs will be placed at a location with average velocity for sampling.

Task 7 – Waste Characterization

The standard testing technique used for assessing hazardous waste characteristics is the Toxicity Characteristic Leaching Procedure (TCLP, SW846-1311). The test protocol involves exposing a 100-gram sample of ash to 1-liter of acidic solution (acetic acid-or acetate based) for 24 hours. The solution is then analyzed for several metals (including mercury) to determine how much of each target metal was leached from the solid sample. Results are compared against limits

established by regulation. In the case of mercury, a maximum leachable level of 0.2 mg/liter has been established. (Note: in most cases the TCLP limits for mercury cannot be exceeded even if all the mercury leaches. These tests will be performed to establish a record of the wastes generated during the program.)

A second series of tests will be performed to answer the question of the stability of the mercury. The potential long-term environmental impact of the mercury-laden ash will be determined using a leaching method known as the synthetic groundwater leaching procedure (SGLP) (Hassett, et al. These tests will be conducted by the Microbeam Technologies Inc. This test is modeled after the TCLP, but modified to allow for disposal scenarios. A shake extraction technique is used to mix the solid sample with an aqueous solution. Aliquots of the liquid are then analyzed after 18 hours, 2 weeks, and 4 weeks.

Sampling and QA/QC procedures will be documented in the test plan as described in Subtask 5.4.

Task 8 – Design and Economics of Site Specific Control System

After completion of testing and analysis of the data, the requirements and costs for full-scale, permanent commercial implementation of the necessary equipment for mercury control using sorbent injection technology will be determined. It will be necessary to meet with PG&E engineering and environmental affairs personnel to develop plant specific design criteria. Process equipment shall be sized and designed based on test results and the plant specific requirements (reagent storage capacity, plant arrangement, retrofit issues, winterization, controls interface, etc.). A conceptual design document shall be developed with drawings and equipment lists. Modifications to existing plant equipment shall be determined and a work scope document developed based on input from the plant that may include modifications to the particulate collector, ash handling system, compressed air supply, electric power capacity, other plant auxiliary equipment, utilities and other balance of plant engineering requirements.

A cost estimate to implement the control technology will be developed. This shall include capital cost estimates for mercury control process equipment as well as projected annual operating costs. Where possible, order-of-magnitude estimates will be included for plant modifications and balance of plant items

Task 9 – Site Report

A site report documenting all measurements, test procedures, analyses, and results obtained in Tasks 2 through 8 will be prepared. This report shall be a stand alone document providing a comprehensive review of the testing and data analysis.

KEY PERSONNEL

The overall program manager for ADA-ES is Dr. Michael Durham. Jean Bustard is coordinating the efforts among all sites. Travis Starns is project manager for the field evaluation at Salem Harbor with assistance in planning from Jean Bustard. Table 6 presents key personnel, their roles and phone numbers for the Salem Harbor field evaluation.

Table 6
Key Project Personnel for Salem Harbor Hg Field Evalation

NAME	COMPANY	ROLE	PHONE #	EMAIL
Michael Kane	PG&E NEG	Project Engineer	508 549-5918	michael.kane@neg.pge.com
Allen Sload	PG&E NEG	Engineering Manager	978 740-8211	allen.sload@neg.pge.com
Doug Bondar	PG&E NEG	Performance Engineer	978 740-8369	douglas.bondar@neg.pge.com
Travis Starns	ADA-ES	Site Project Manager	303-734-1727	traviss@adaes.com
Sheila Haythornthwaite	Self	Consultant	410 719-8755	sheila.haythorn@verizon.net
Rui Afonso	Energy & Environmental Strategies	Consultant	508-756-5522	rui.afonso@ees-consultants.com
Michael Durham	ADA-ES	Program Manager	303 734-1727	Miked@adaes.com
Jean Bustard	ADA-ES	Project Planning	303 734-1727	Jeanb@adaes.com
Sharon Sjostrom	Apogee Scientific	Hg S-CEM	303 783-9599	Ssjostrom@apogee-sci.com
Cam Martin	ADA-ES	Equipment Design	303 734-1727	Camm@adaes.com
Richard Schlager	ADA-ES	Contracts	303 734-1727	Richards@adaes.com
Connie Senior	Reaction Engineering	Waste Issues	801 364 6925 ext 37	senior@reaction-eng.com
Steve Johnson	Quinapoxet Solutions	Consultant	603 425-6765	stevej.quinny@verizon.net
Ramsay Chang	EPRI	Air Toxics Expert	650 855-2535	Rchang@epri.com

REFERENCES

1. "PG&E NEG Brayton Point Power Plant Sorbent Injection into Cold-Side ESP for Mercury Control," Test Plan Prepared by ADA-ES, April 16, 2002.

APPENDIX A
DESCRIPTION OF SEMI CONTINUOUS EMISSIONS MONITOR FOR MERCURY

Mercury S-CEM

A semi-continuous mercury analyzer will be used during this program to provide near real-time feedback during baseline, parametric and long-term testing. Continuous measurement of mercury at the inlet and outlet of the particulate collector is considered a critical component of a field mercury control program where mercury levels fluctuate with boiler operation (temperature, load, etc.) and decisions must be made concerning parameters such as sorbent feed rate and cooling. The analyzers that will be used for this program consist of a commercially available cold vapor atomic absorption spectrometer (CVAAS) coupled with a gold amalgamation system (Au-CVAAS). Radian developed this type of system for EPRI (Carey, et al., 1998). A sketch of the system is shown in the figure below. One analyzer will be placed at the inlet of the particulate collector and one at the outlet of the particulate collector during this test program.

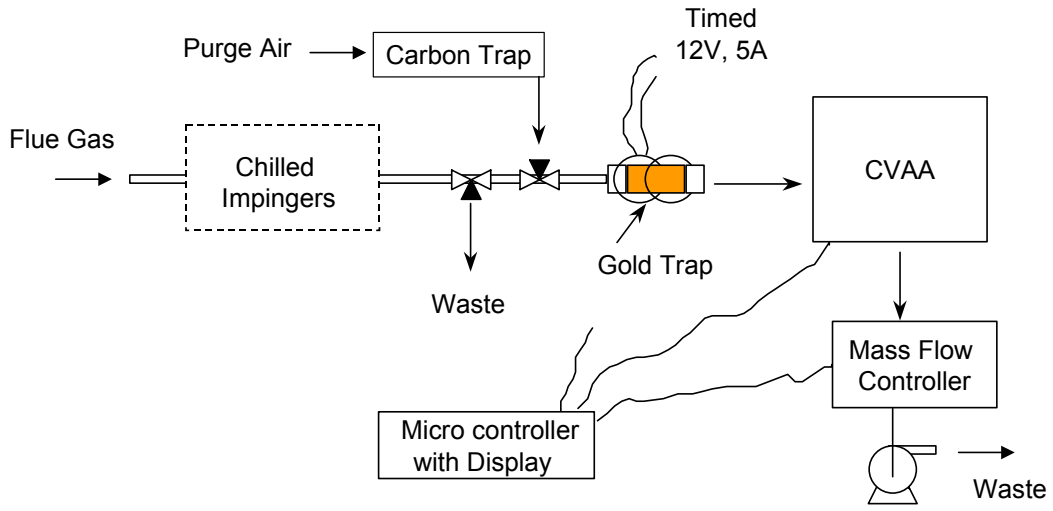


Figure C-1
Sketch of Mercury Measurement System

Although it is very difficult to transport non-elemental mercury in sampling lines, elemental mercury can be transported without significant problems. Since the Au-CVAAS measures mercury by using the distinct lines of UV absorption characteristic of elemental Hg (Hg^0), the non-elemental fraction is either converted to elemental mercury (for total mercury measurement) or removed (for measurement of the elemental fraction) near the sample extraction point. This minimizes any losses due to the sampling system.

For total vapor-phase mercury measurements, all non-elemental vapor-phase mercury in the flue gas must be converted to elemental mercury. A reduction solution of stannous chloride in hydrochloric acid is used to convert Hg^{2+} to Hg^0. The solution is mixed as prescribed in the draft Ontario Hydro Method for manual mercury measurements.

To measure speciated mercury, an impinger of potassium chloride (KCl) solution mixed as prescribed by the draft Ontario Hydro Method is placed upstream of the stannous chloride solution to capture oxidized mercury. Unique to this instrument is the ability to continuously refresh the impinger solutions to assure continuous exposure of the gas to active chemicals.

The Au-CVAAS system is calibrated using elemental mercury vapor. The instrument is calibrated by injecting a metered volume of mercury-laden air into the analyzer. The mercury-laden air is from the air-space of a vial containing liquid mercury at a precisely measured temperature. The concentration of the mercury in the air is determined by the vapor pressure of the mercury at that temperature.

The Au-CVAAS can measure mercury over a wide range of concentrations. Since the detection limit of the analyzer is a function of the quantity of mercury on the gold wire and not concentration in the gas, the sampling time can be adjusted for different situations. Laboratory tests with stable permeation tube mercury sources and standard mercury solutions indicate that the noise level for this analyzer is 0.2 ng mercury. It is reasonable to sample at 50 – 100 times the noise level, therefore, during field testing the sampling time is set so at least 10 ng mercury is collected on the wire before desorption. The following table shows the sampling time required for different concentrations of mercury in the flue gas with 2 liters per minute sample flow.

Sampling Time Required for Au-CVAA Analyzer

VAPOR-PHASE MERCURY CONCENTRATION ($\mu G/M^3$)	MINIMUM SAMPLE TIME (MIN)	NOISE LEVEL ($\mu G/M^3$)
5	1	0.1
2.5	2	0.05
1	5	0.02
0.5	10	0.01

An oxygen analyzer will be placed downstream of the Au-CVAAS to monitor and store the oxygen levels in the gas stream. This is particularly useful when measuring changes in mercury across a pollution control device on a full-scale unit where air inleakage into the unit may dilute the gas sample and bias results. It is also useful to assure that no leaks develop in the sampling system over time.

Particulate is separated from the gas sample using a self-cleaning filter arrangement modified for use with this mercury analyzer under an EPRI mercury control program. This arrangement uses an annular filter arrangement where excess sample flow continuously scours particulate from the filter so as to minimize any mercury removal or conversion due to the presence of particulate.

The mercury analyzer described has been used extensively for lab testing and field testing at three full-scale coal-fired power plants burning Powder River Basin (PRB), eastern

bituminous, and lignite coals under EPRI programs. Although draft Ontario Hydro mercury measurements were not conducted while the analyzer was on-site, levels measured by the analyzer were well within the range expected based on previous measurements with either the draft Ontario Hydro Method or a solid carbon trap.

In order to assure the quality of the data to be obtained during the field operations, Standard Operating Procedures have been developed and will be followed for these tests.

APPENDIX B
RESULTS OF PRE-BASELINE TESTS AT SALEM HARBOR, FEBRUARY 2001

ADA Environmental Solutions, LLC

8100 SouthPark Way, B-2
Littleton, Colorado 80120
Fax: 303.734.0330
***303.734.1727** or 1.888.822.8617*

memorandum

To:	Doug Bondar, Mike Kane, Allen Sload, Steve Johnson, Rui Afonzo, Sharon Sjostrom
From:	Jean Bustard
CC:	Connie Senior, Mike Durham, Richard Schlager, John Comer
Date:	March 9, 2001
RE:	Preliminary results from pre-baseline mercury measurements (February 12 – 22)

Primary Goals for Pre-Baseline Mercury Measurements, Phase I:

1. Calibrate 3 vapor phase mercury Semi-Continuous Emission Monitors (S-CEMs) provided by Apogee Scientific at one location.
2. Obtain mercury measurements to compare to ICR tests.
3. Measure vapor phase mercury at 3 locations on Unit 3:
   a) Economizer outlet
   b) ESP inlet
   c) Stack
4. Measure vapor phase mercury at 3 locations on Unit 1:
   a) Economizer outlet
   b) ESP inlet
   c) Stack
5. Collect plant operating data and coal/ash samples.

Completed Tasks:

1) Salem Harbor personnel constructed test shelters at the ESP inlet on Unit 1 and 3
2) Set-up 3 analyzers at Unit 1 economizer outlet for calibration and signal comparison (2/13 – 15/01).
3) Moved analyzers to 3 locations on Unit 3 (2/15-16/01).
   – economizer outlet on-line the evening of 2/15
   – ESP inlet on-line the afternoon of 2/16
   – stack on-line afternoon of 2/16
4) Collected in-situ ash samples from Unit 3 economizer outlet (2/18/01)
5) Moved analyzer from Unit 3 stack to Unit 1 stack (2/19/01)
6) Operated with urea injection off for 1 hour (2/20/01)
7) Collected in-situ ash samples from Unit 3 economizer outlet (2/20/01)
8) Operated with urea injection off for 4 hours (2/21/01)
9) Collected in-situ ash samples from Unit 3 economizer outlet (2/21/01)
10) Salem Harbor personnel collected ESP hopper ash and coal samples

Description, Measurement and Characteristics of SCEMs:

A complete description of the SCEMs is included in the appendix of this pre-baseline test plan. It is important to note that these instruments only measure vapor phase mercury. Any particulate mercury, will not be seen by these analyzers. This needs to be viewed with respect to the manual Ontario Hydro measurements that were made during the ICR tests. These tests measure both particulate and vapor phase mercury. However, the OH method is subject to artifact removal of vapor phase mercury on the particulate. In many situations, the OH measurements made under high particle loading conditions (i.e. inlet to the ESP) will report that most of the mercury is in the particulate form when actually it was a vapor when it entered the sampler.

As a reminder of the ICR results at Salem Harbor, the OH measurements at the inlet to the ESP showed that 2.8 ug/m^3 was associated with particulate mercury and only 0.4 ug/m^3 was vapor. Therefore, an important result of these pre-baseline tests was to determine if the mercury at Salem Harbor was truly particulate or the result of a measurement artifact.

Another characteristic of the SCEMs that is important in understanding these results is the lower detection limit. As described in the Appendix, the SCEMs are capable of operating a lower concentrations by increasing the sampling time. However, during these tests "blanks" were not collected at the longer sampling times. Therefore, we report the concentrations at the outlet at "less than 0.2" to account for small sampling artifacts at the longer sampling times.

Preliminary Test Results and Analysis:

- A summary of the completed test matrix is presented in Table 1.
- The attached graphs were provided by Sharon Sjostrom at Apogee. Figures 1 and 2 present time histories of pertinent parameters during testing on Unit 3. These graphs show:
  1. Total vapor phase mercury at the 3 test locations
  2. Elemental mercury at the 3 test locations
  3. Gas temperature at the economizer outlet
  4. Gas temperature at the reheat section
  5. Boiler load
  6. Urea flow
  7. Opacity
  8. Oil flow
- Figures 3 and 4 present the same set of graphs graphs during testing on Unit 1.
- Figure 5 presents stack mercury measurements on Unit 1.
- A summary of the results from both units is presented in Table 2.
- A final analysis will be conducted after coal and ash tests are completed.
- Table 3 presents a list of ash/coal samples collected during this test period.
- Table 4 presents the samples and tests that will be conducted initially. If necessary, additional tests will be scheduled. Connie Senior with PSI will oversee the coal and ash tests.
- The original test schedule was revised to reduce the number of test locations because of the time required to move and maintain the S-CEMs, and to obtain more data from Unit 3.

Preliminary Conclusions

Unit 1

- Vapor phase mercury was steady at the Unit 1 economizer outlet at nominally 3.3 (μg/Nm3). This value is proportional to mercury levels reported in the coal during the ICR tests.
- Vapor phase mercury at the Unit 1 stack is typically less than 0.2 (μg/Nm3).
- Unit 1 showed nominally 94% mercury control. This is higher than models predict for an ESP. These models include only removal of mercury by sorbents (flyash or others) in-flight and do not incorporate any additional removal in the ESP.

Unit 3

- Vapor phase mercury varied from < 0.2 to 3.5 (μg/Nm3) at the Unit 3 economizer outlet. Preliminary tests show that there was particulate phase mercury at this location.
- Vapor phase mercury varied between 0.4 and 2.0 (μg/Nm3) the Unit 3 ESP inlet. This shows that there is higher vapor phase mercury at this location than indicated by the ICR tests. This indicates that the high particulate measured by the OH measurements were artifacts and the majority of this mercury was really in the vapor phase.
- Vapor phase mercury is less than 0.2 (μg/Nm3) at the Unit 3 stack. This shows that an unusually high amount of vapor phase mercury was removed across the ESP.
  This is very encouraging for other applications with ESPs. The ICR results indicated significant particulate phase mercury at the ESP inlet. This has often been interpreted to suggest in-flight capture of vapor-phase mercury by the flyash upstream of the ESP and subsequent removal in the ESP. The recent data suggests significant vapor-phase mercury removal is occurring within the ESP.
- In most cases, vapor phase mercury at the economizer outlet and ESP inlet showed similar trends and similar mercury concentrations. This indicates that there is very little vapor phase mercury removal between these locations.
- Vapor phase mercury appears to oxidize across the air preheater. Similar results were seen across the hot-side ESP/air preheater at Gaston.
- Some inconsistencies at the economizer outlet warrant further exploration.
- During short-term urea stoppage, results were inconclusive.

Table 1: Test Matrix Pre-Baseline Tests Phase I

Location	Analyzer A	Analyzer B	Analyzer C	Dates/Comments
Unit 1 Economizer Outlet	X	X	X	Feb 13 - 15
Unit 1 Stack	X			Feb 19 - 21
Unit 3 Economizer Outlet			X	Feb 15 - 21
Unit 3 ESP Inlet		X		Feb 16 - 21
Unit 3 Stack	X			Feb 16 - 18

Table 2: Summary of S-CEM Measurements

Location	Speciation	Concentration
Unit 1 Economizer Outlet	Total	2.9 – 3.7 ($\mu g/Nm^3$)
Unit 1 Stack	Total	0.24 – 0.39 ($\mu g/Nm^3$)
Unit 3 Economizer Outlet	Total	< 0.2 – 3.5 ($\mu g/Nm^3$)
Unit 3 ESP Inlet	Total	0.3 – 2.0 ($\mu g/Nm^3$)
Unit 3 Stack	Total	<0.2 – 0.42 ($\mu g/Nm^3$)
Unit 1 Economizer Outlet	Elemental	NA ($\mu g/Nm^3$)
Unit 1 Stack	Elemental	<0.2 ($\mu g/Nm^3$)
Unit 3 Economizer Outlet	Elemental	0.2 – 1.2($\mu g/Nm^3$)
Unit 3 ESP Inlet	Elemental	< 0.2 – 1.1 ($\mu g/Nm^3$)
Unit 3 Stack	Elemental	< 0.2 – 0.33 ($\mu g/Nm^3$)
Unit 1 Economizer Outlet	Oxidized	NA
Unit 1 Stack	Oxidized	35 – 50 %
Unit 3 Economizer Outlet	Oxidized	20 – 30 %
Unit 3 ESP Inlet	Oxidized	50 - 90%
Unit 3 Stack	Oxidized	10 – 50 %

Table 3. Ash and Coal Sample Log – Salem Harbor Prebaseline Tests

Date	Coal	Ash	Analyzer Locations
2-14-01	U3	U3 A row	A at U1 Eco Out
		U3 B row	B at U1 Eco Out
		U3 C row	C at U1 Eco Out
		U3 D row	
2-15-01	U3	U3 A row	A at U1 Eco Out am, U3 stack pm (not running pm)
		U3 B row	B at U1 Eco Out am, U3 ESP in pm (not running pm)
		U3 C row	C at U1 Eco Out am, U3 Eco out pm
		U3 D row	
2-20-01	U1	U1 A row	A at U1 stack
		U1 B row	B at U3 ESP In
		U1 C row	C at U3 Eco Out
		U1 D row	
	U3	U3 A row	
		U3 B row	
		U3 C row	
		U3 D row	
2-21-01	U1	U1 A row	A at U1 stack
		U1 B row	B at U3 ESP In
		U1 C row	C at U3 Eco Out
		U1 D row	
	U3	U3 A row	
		U3 B row	
		U3 C row	
		U3 D row	

Table 4: Schedule of Coal and Ash Tests

Sample ID	Date	Time	Sample	Unit	Sample Location	Hg	Cl	Ult Prox	Ash Chem	CCSEM	NH3
SH3-CO-02	2/15/01	15:00	Coal	3	Coal	●	●	●			
SH1-CO-04	2/20/01	10:30	Coal	1	Coal	●	●	●	●	●	
SH1-FA-A04	2/20/01	9:00	Ash	1	U1 A Row	●					●
SH1-FA-B04	2/20/01	9:00	Ash	1	U1 B Row	●					●
SH1-FA-C04	2/20/01	9:00	Ash	1	U1 C Row	●					●
SH1-FA-D04	2/20/01	9:00	Ash	1	U1 D Row	●					●
SH3-CO-03	2/20/01	10:30	Coal	3	Coal	●	●	●	●	●	
SH3-FA-A03	2/20/01	8:30	Ash	3	U3 A Row	●					●
SH3-FA-B03	2/20/01	8:30	Ash	3	U3 B Row	●					●
SH3-FA-C03	2/20/01	8:30	Ash	3	U3 C Row	●					●
SH3-FA-D03	2/20/01	8:30	Ash	3	U3 D Row	●					●
SH1-CO-05	2/21/01	12:45	Coal	1	Coal	●	●	●			
SH3-CO-06	2/22/01	8:35	Coal	3	Coal	●	●	●			

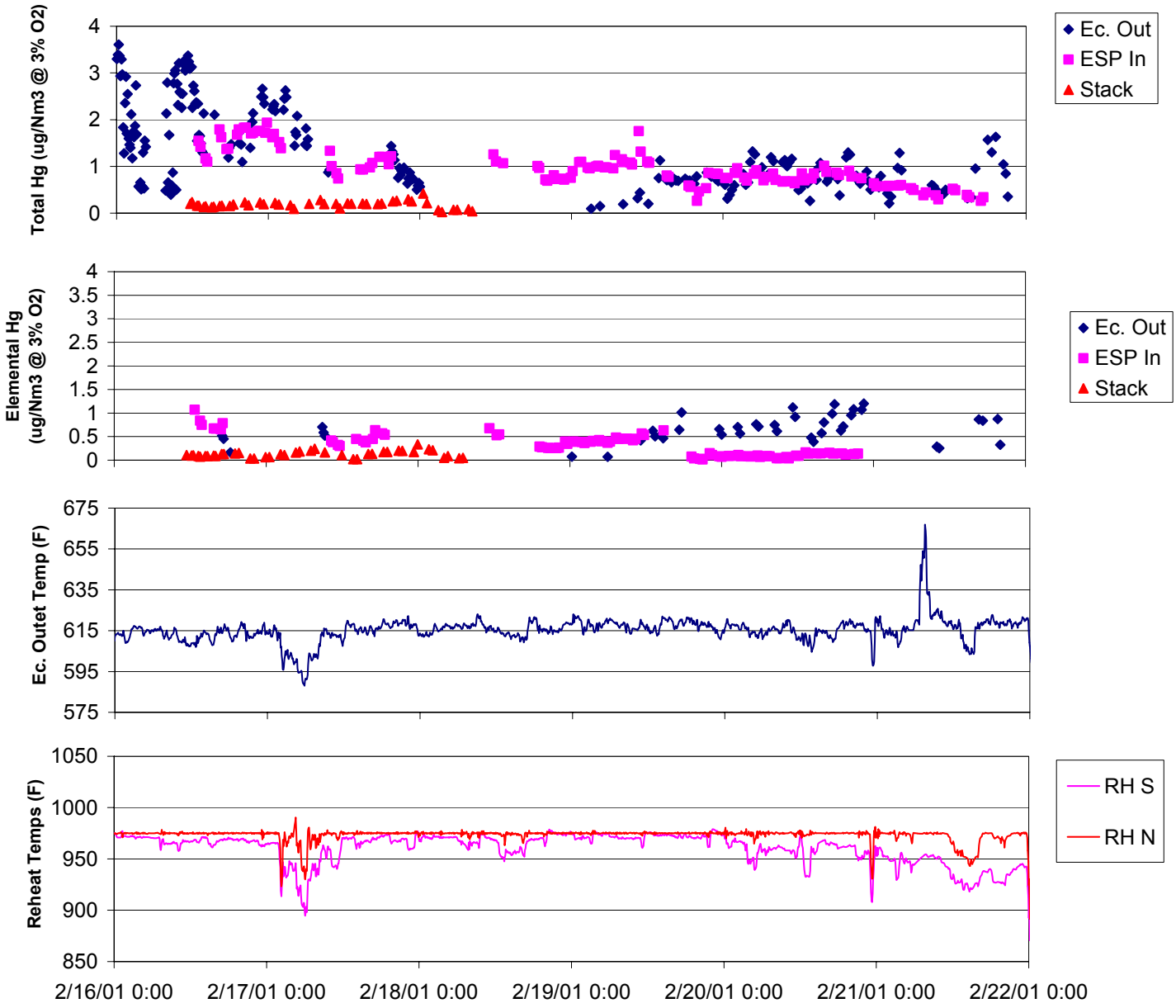


Figure 1. Mercury measurements at Salem Harbor, Unit 3.

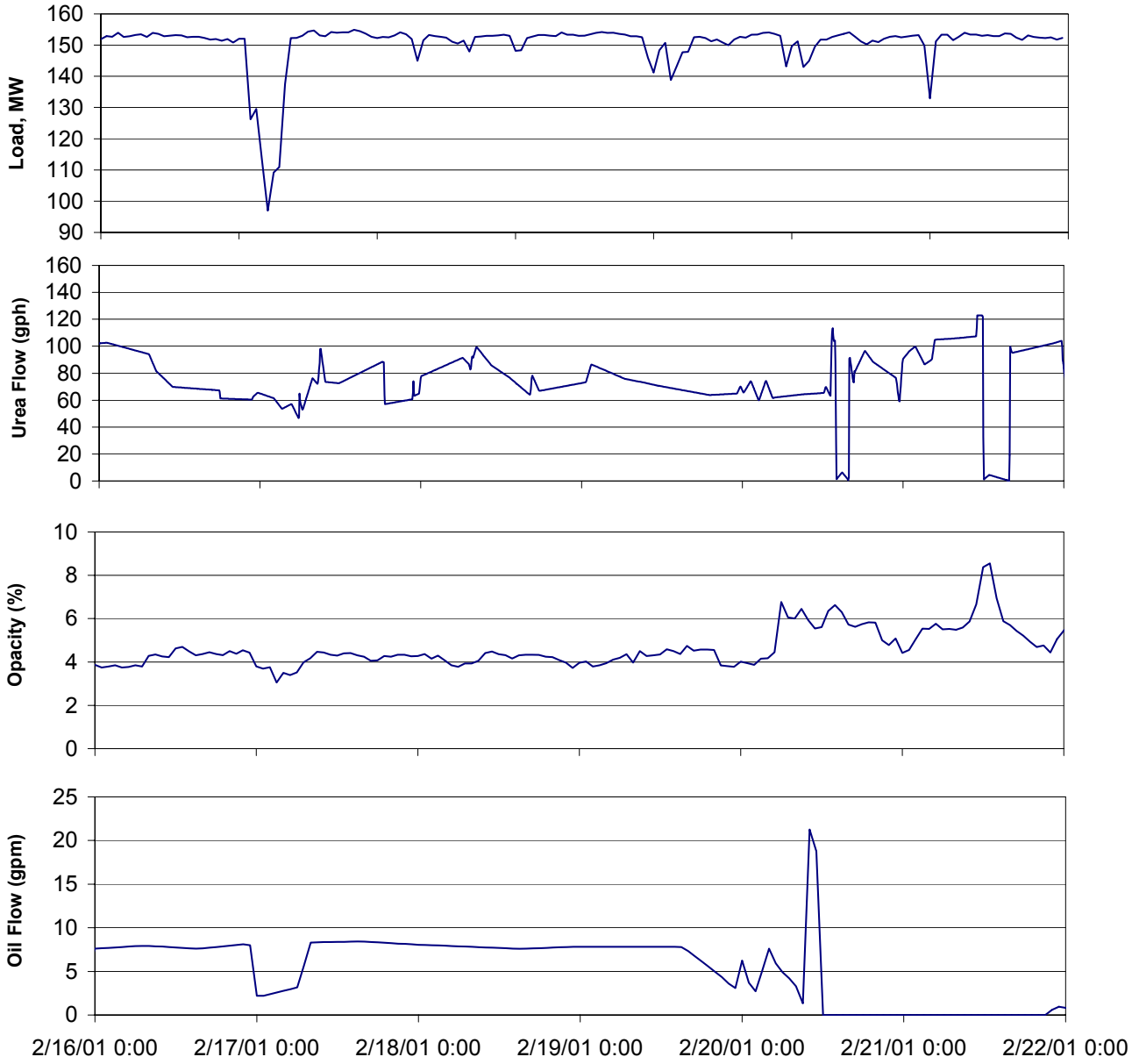


Figure 2. Plant operation during mercury measurements at Salem Harbor, Unit 3.

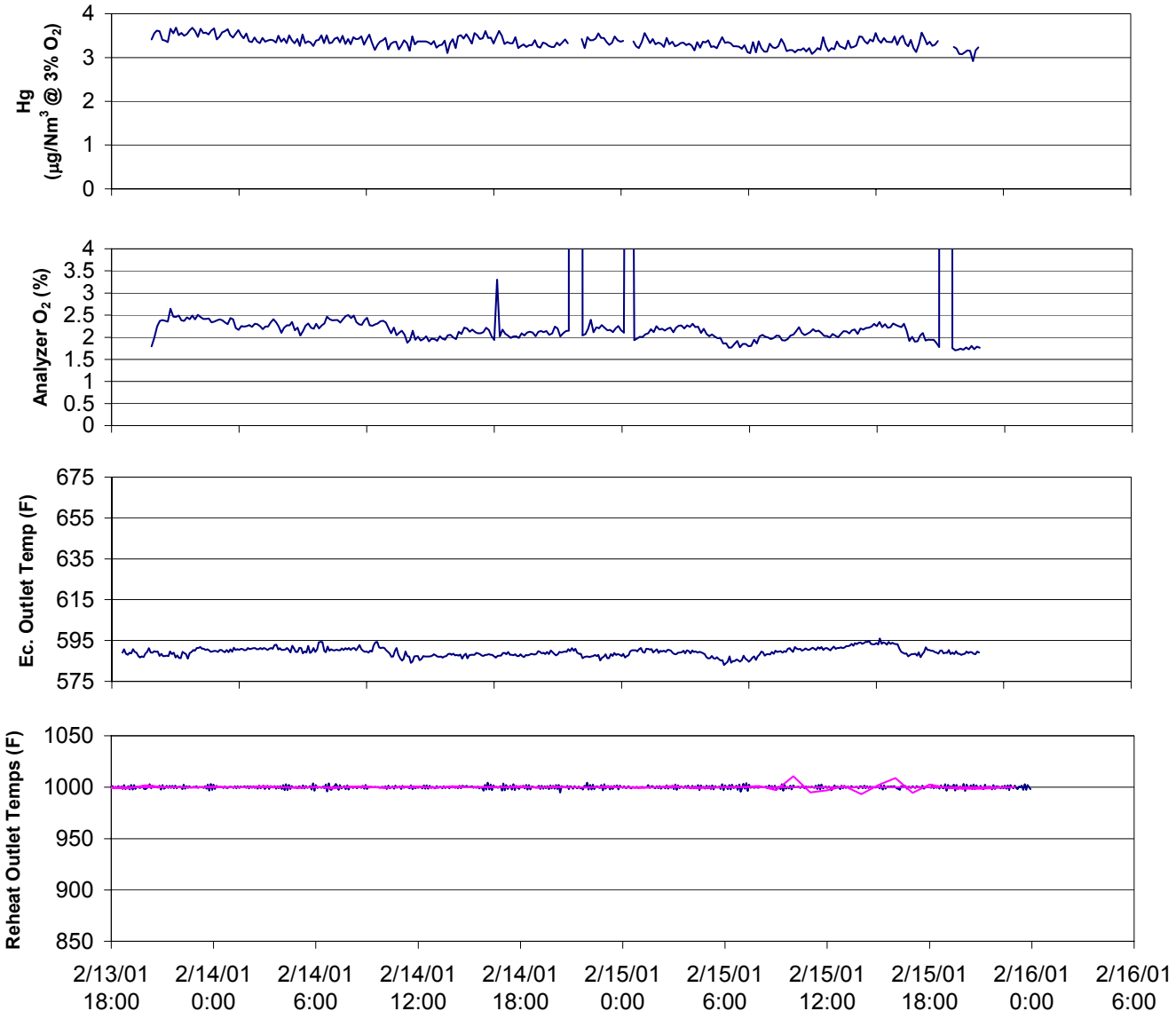


Figure 3. Mercury measurements at Salem Harbor, Unit 1.

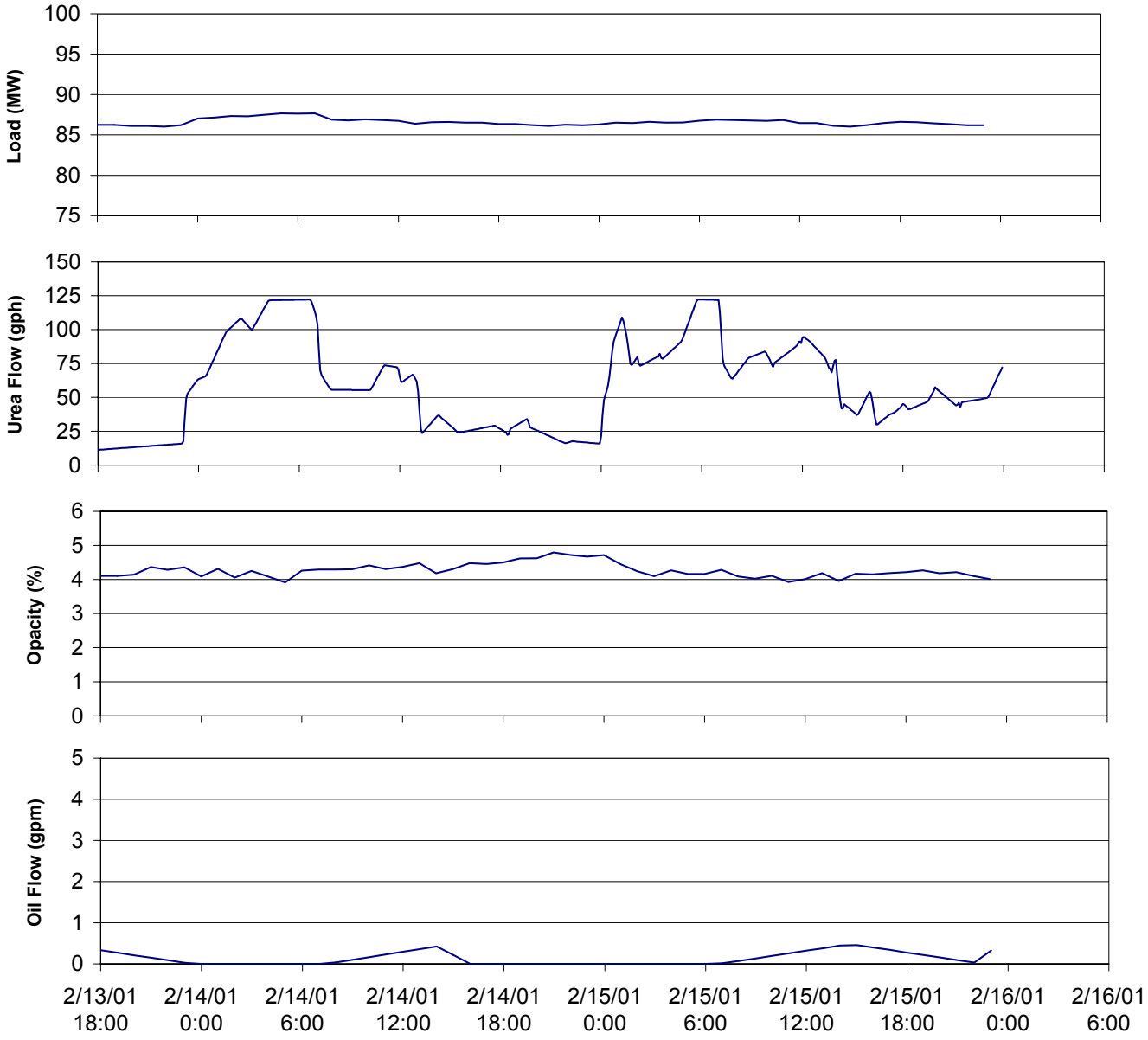


Figure 4. Plant operation during mercury measurements at Salem Harbor, Unit 1.

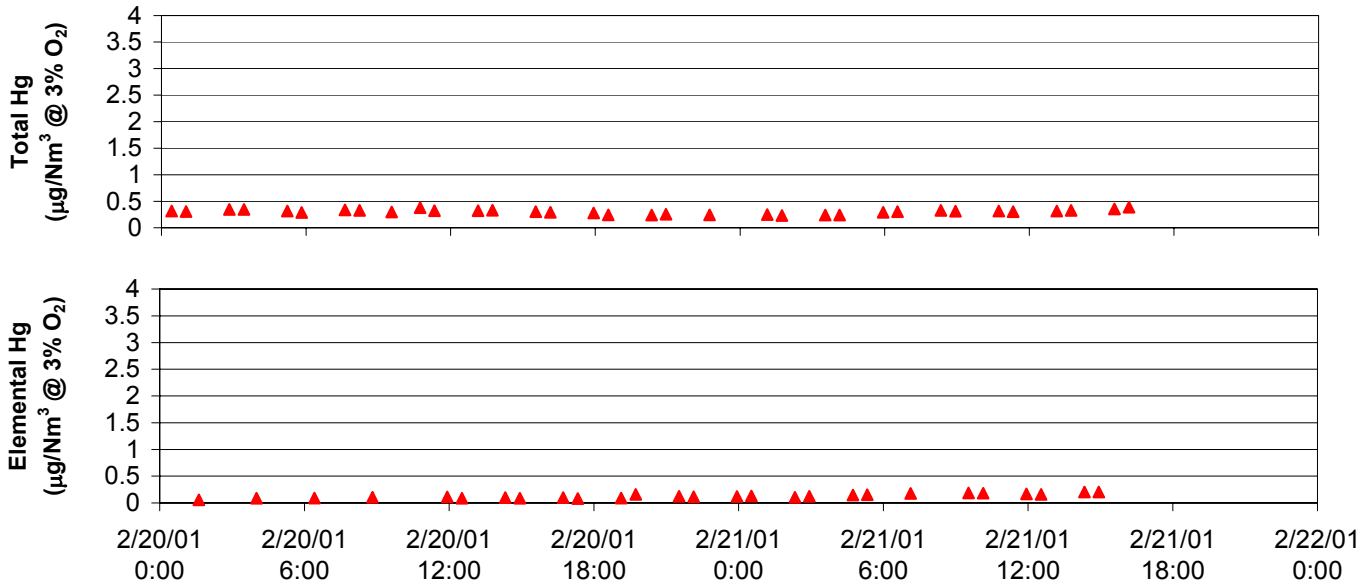


Figure 5. Mercury Measurements at the Salem Harbor, Unit 1 stack.

APPENDIX C
SALEM HARBOR DRAFT QUALITY ASSURANCE PROJECT PLAN (TRC)

SEPTEMBER 2002

DRAFT
Quality Assurance

Program Plan (QAPP)

Emissions Testing in Support of U.S. Department of Energy National Energy Technology Laboratory's Full Scale High Efficiency Mercury Removal Efficiency Evaluation of Unit 1 at Salem Harbor Generating Station

Prepared for:

ADA-Environmental Solutions, LLC
8100 South Park Way, B-2
Littleton, Colorado 80120

Prepared by:

TRC Environmental Corporation
Boott Mills South
Foot of John Street
Lowell, Massachusetts 01852

September 2002

TRC Project No. 02437-0040-00000

September 2002

QUALITY ASSURANCE PROGRAM PLAN (QAPP)

Emissions Testing in Support of U.S. Department of Energy National Energy Technology Laboratory's Full Scale High Efficiency Mercury Removal Efficiency Evaluation of Unit 1 At Salem Harbor Generating Station

Prepared for

ADA-Environmental Solutions, LLC
1 Bowdoin Square
Boston, MA 02114

Prepared by

TRC Environmental Corporation
Boott Mills South - Foot of John Street
Lowell, Massachusetts 01852
(978) 970-5600

DISCLAIMER

TITLE AND APPROVAL SHEET

Quality Assurance Program Plan (QAPP)
Emissions Testing in Support of
U.S. Department of Energy
National Energy Technology Laboratory's
Full Scale High Efficiency Mercury Removal Efficiency Evaluation of Unit 1
At the Salem Harbor Generating Station

Approval Signatures

ADA-Environmental Solutions, LLC Program Coordinator	Name	Date
TRC Environmental Corporation Project Manager	Michael P. Martin	Date
TRC Environmental Corporation Quality Assurance Officer	Howard F. Schiff	Date
US DOE, NETL Quality Assurance Officer	Name	Date

TABLE OF CONTENTS AND DOCUMENT CONTROL FORMAT

Section ***Page Number***

LIST OF TABLES

LIST OF FIGURES

Number

DISTRIBUTION LIST

ADA-ES, LLC

TRC Environmental Corporation

Michael P. Martin
Howard F. Schiff
Edward MacKinnon

Philips Services Corporation

Ron McLoed

US DOE, NETL

PROJECT ORGANIZATION

Purpose/Background

The purpose of the project organization is to provide a clear understanding of the role that each party plays in the study and to provide lines of authority and reporting.

Roles and Responsibilities

Table 11 of the ADA-Environmental Solutions, LLC's Salem Harbor Mercury Test Plan shows the organization of the individuals responsible for each element of the overall program and the primary lines of communication.

ADA-Environmental Solutions, LLC

The ADA-Environmental Solutions, LLC (ADA-ES) Program Coordinator is Mr. Travis Starns He will provide the overall program coordination amongst the Plant Program Coordinator at the facility to be tested, ADA, and TRC Environmental Corporation. The ADA Program Coordinator will review the Quality Assurance Program Plan (QAPP), the Site Specific Test Plan (SSTP), the test report and submit the final versions the Department of Energy (DOE). The ADA-ES Plant Program Coordinator at Salem Harbor will coordinate the unit operations; the coal sampling and emissions test during each test run.

TRC Environmental Corporation

TRC Environmental Corporation (TRC) will conduct the emissions testing program for ADA-ES, as contracted by the Department of Energy, National Energy Technology Laboratory, (NETL).

TRC's Program Manager

The TRC Environmental Corporation Program Manager is Mr. Michael Martin. He shall have the full responsibility and authority from both a technical and administrative standpoint for the successful conduct of this work. He will be the principal point of contact with the ADA-ES Program Coordinator for all matters relating to contract performance and technical progress.

Working with TRC's Laboratory Coordinator, TRC's Program Manger will manage the assignment of analytical work to the analytical laboratories. Ultimately, TRC's Program Manager will be responsible for assuring that all tasks are completed on schedule and within budget, while maintaining the quality objectives of the program. To do so, TRC's Program Manager will carry out the following functions:

- Administer program activities within the TRC team.
- Coordinate activities within the TRC team.
- Attend program meetings.
- Conduct pretest site-specific survey.
- Effect corrective actions which include quality, budget and schedule maintenance measures.
- Interact with the sampling team to ensure proper performance of the test procedures.
- Communicate directly with the ADA-ES Program Manager.
- Prepare or review Site Specific Test Plan
- Review the QAPP.

- Prepare or review the site-specific test report.
- Review the data validation and reduction.

In summary, TRC's Program Manager will ensure that the program is effectively staffed, managed coordinated and satisfactorily completed.

TRC's QA Officer

Program Quality Assurance /Quality Control will be under the direction of Mr. Howard F. Schiff, Program QA Officer. He will be responsible for ensuring that all program deliverables adhere to the highest quality principles. He will report programmatically to the Program Manager, but he derives his authority from the TRC Air Measurements Manger.

TRC's QA Officer will initiate or follow up on corrective actions and aid in the preparation of a section of the site-specific final report summarizing QA/QC activities. Quality problems identified and corrective actions taken will also be described in this section of the reports.

TRC's QA Officer will carry out the following functions:

- Implement all QA procedures.
- Prepare or review the QAPP.
- Review and approve the Site Specific Test Plan (SSTP) prior to submittal.
- Ensure that all required equipment calibrations are conducted prior and subsequent to each field test.
- Provide written summaries of Program QC activities for submission to the Program Manager.
- Advise technical staff of appropriate QC measures and corrective actions, prepare QC procedure write-up, as needed.
- Assist in Data analysis.
- Review Site Specific Final Test Reports.

TRC's Laboratory Coordinator

Laboratory Coordination and data validation will be under the direction of Mr. Edward MacKinnon, who will carry out the following functions:

- Act as the laboratory coordinator between the sampling team(s) and the analytical laboratories.
- Communicate the specific analytical QC requirements to the laboratories.
- Supervise the schedule and budget for the laboratories.
- Receive, validate and distribute the laboratory data.
- Assist in data analysis.
- Assist in report preparation.

Field Team Leader's Responsibilities.

The Field Team Leader will coordinate the activities of the sampling team. He is experienced in managing emissions measurement programs and in performing source-sampling methodologies. He will:

- Supervise the source sampling train operators.
- Coordinate the sampling program with the Plant Program Coordinator
- Assist the train operators in trouble-shooting and maintaining the sampling trains.
- Collect all sampling train data sheets, determine isokinetic ratios, determine acceptability of train leak checks and ensure that each train is operated in accordance with the EPA sampling protocol.
- Oversee the recovery, packing and shipping of the samples to the respective analytical laboratory.
- Inform the TRC Program Manager, and ADA-ES Program and Plant Program Coordinators on which sampling runs meet all validating criteria and if not to determine if additional sampling runs are to be conducted.

Analytical Laboratory Responsibilities

The contracted analytical laboratory, Phillips Services Corporation (PSC) of Burlington Ontario, Canada, will be responsible for sample analysis and assisting with data reporting. The contracted laboratory will be responsible for conducting the analyses in accordance with the methods and procedures specified in this QAPP. Specifically, PSC will analyze the Ontario Hydro Mercury train samples.

The laboratory manager will be responsible to ensure that the QAPP is followed. In summary, the laboratory managers will perform the following duties:

7. ● Ensure that laboratory services are available to support the sample analysis in a timely fashion.
8. ● Ensure that the Program Quality Assurance Program Plan is followed.
9. ● Ensure that the laboratory QA/QC procedures are implemented.

10.
PROBLEM DEFINITION/BACKGROUND

Purpose/Background

The background information provided in this element will place the problem in historical perspective.

Problem Statement and Background

ADA-ES in under contract to the USDOE-NETL to conduct full-scale high-efficiency mercury removal tests at selected electric utilities. ADA will be conducting an evaluation of various dry sorbent injection materials for mercury emission control. TRC is providing emission-testing support to ADA-ES during Baseline and Optimized Condition testing to be performed at the Salem Harbor Generating Station.

Facility Description

A5.3.1 Salem Harbor Generating Station

The Salem Harbor Generating Station is located in Salem, Massachusetts. Units 1, 2, and 3 combust "Solid Fossil Fuel" so the facility is directly subject to 310 CMR 7.29. Unit 4 is part of the affected facility, although it combusts #6 fuel oil. Electrostatic precipitators (ESPs) are used to control particulate emissions from Units 1, 2, 3 and 4. The test program will be conducted on Unit 1.

A5.3.1.1 CEMS

Unit 1 is equipped with a continuous emission monitoring system (CEMS). The CEMS measures and reports the stack opacity, volumetric flow rate, and CO_2, SO_2, NO_x, and CO in the exhaust gas.

PROGRAM DESCRIPTION AND SCHEDULE

Purpose/Background

The purpose of the program description element is to provide the participants with a background understanding of the project and the types of activities to be conducted, including the measurements that will be taken and the associated QA/QC goals, procedures and timetables for collecting the measurements.

Description of Work to Be

Measurements

Salem Harbor Unit 1

Measurements to be made during this program of the flue gas in the inlet duct and outlet duct of the final pollution control device include:

- Mercury Speciation by the USEPA EMC-Pre-003 Draft Ontario-Hydro Sampling Method;
- Flue Gas Flow Rate by EPA Method 2;
- Oxygen and Carbon Dioxide by EPA Method 3B;
- Multi-Metals and Particulate by EPA Method 29 (outlet duct only); and
- Flue Gas moisture by EPA Method 4.

Operations data to be obtained will include but not be limited to:

Electrical generation	KW
Main steam flow	K lb/hour
Main steam temp.	ºF
Main steam pressure	PSIG
Reheater steamer flow	K lb/hr
Feed water flow	K lb/hr
Furnace draft	in H_2O
Wind box pressure	in H_2O
Air heater temperature	in ºF, out ºF
Mills in operation	Total #
Burners in operation	Total #
Combustion airflow	K lb/hr
Furnace O_2	%
Stack CO	ppm

ESP operations data for each TR set
- PV - Primary volts
- PA - Primary amps
- SV - Secondary volts
- SA - Secondary amps

See the SSTP for a detailed listing.

Specific Quality Standards, Criteria and Objectives

There are no emissions standards for mercury to which the data is to be compared to. This program is being conducted to determine removal efficiencies of the various sorbent materials in order to provide data for development of mercury emission control technology.

Personnel and Equipment Requirements

TRC personnel assigned to this project are experienced in the setup, operation and recovery of the Ontario Hydro Method and USEPA Method 29 for multi metals. The equipment utilized during emission testing will conform to the requirements of the test methods.

Assessment Techniques Needed For Project

Data collected during this program will be evaluated against the stated objectives of the program and the precision and accuracy goals stated in this QAPP. All raw field data is reviewed after each sampling run to ensure that the data collection meets the all QA requirements for the run to be valid. For example: final sampling train leak rate check shall be less than 0.02 cfm or 4% of the sampling rate; the overall isokinetic sampling ratio shall be between 90 and 110% of true; and all pitot tube leak checks are valid.

The analytical data is reviewed and validated with respect to data quality objectives, e.g., spike recovery, duplicate analytical results within specified limits etc., before data is utilized in calculating emission rates. The data review approach is further defined in section D of this QAPP.

Schedule of work to be performed

The sampling will commence subsequent to the approval of the QAPP and SSTP by USDOE.

Required Record Keeping

TRC, and the analytical laboratories will maintain in project files, for a minimum of 5 years, all records relating to: sampling and analytical methods, test results and conclusions; problems encountered and corrective actions; sampling data sheets and field notebooks; analysis, including data printouts from instruments and laboratory notebooks; results of all field equipment calibrations and analytical instrumentation calibrations; all calculations and data summaries, interpretations and determinations; results of all QC measurements and comparison with project objectives; this QAPP; the SSTP and the final report.

QUALITY OBJECTIVES AND CRITERIA FOR MEASUREMENT DATA

Purpose/Background

This element of the QAPP documents the quality objectives for the measurement data to be collected and establishes performance criteria for the measurement system that will be used in generating the data.

Quality Objectives

Data Quality Objectives (DQOs) are qualitative and quantitative statements describing the performance level required by the data collection system in order to meet regulatory and/or project specific requirements. The process of developing QA objectives helps to ensure that data are of adequate quality for the intended use. The QC measures must be consistent with the DQOs. DQOs must address the following elements:

Accuracy - Establishes how close the obtained data is to the true concentration of a sample. Accuracy is estimated through the comparison of the obtained data to the true value of a spiked sample, a standard reference material (SRM) or a check standard. It is a measure of the bias corresponding to systematic and random errors in the entire data collection process. Sources of error include the sampling processes, field and laboratory contamination, sample preservation and handling, matrix interferences, sample preparation methods, and calibration and analysis procedures. Sampling accuracy is generally assessed through the use of field, equipment and trip blanks; analytical accuracy can be assessed through the use of calibration and method blanks, calibration verification samples and laboratory spike samples. Accuracy will be expressed as percent recovery.

Precision - Defined an acceptable tolerance range for repeatability. It is estimated through the comparison of the results of field and laboratory duplicates, precision of the entire data collection process is determined by the ability of the measurement system to repeat a specific result. Precision may be expressed in a variety of ways including standard deviation, relative standard deviation, range and relative percent difference. Laboratory and field duplicate results in this program should be reported as relative percent difference. Precision of stack gas sampling will not be determined as duplicate co-located sampling trains are not part of this test program.

Minimum Reporting or Detection Limit - Establishes the minimum concentration of a contaminant that must be measured. Calculation of the Method Detection Limit (MDL) must be performed using the procedure described in 40 CFR Part 136, Appendix B, October 26, 1984.

Representativeness - Specifies the degree to which data accurately and precisely represents a characteristic of a population, parameter variation at a sampling point, or a process or environmental condition and how closely the obtained results represent the entire population sampled. Representativeness reflects the design of the sampling program and is maximized by proper selection of sampling locations and collection of a sufficient number of samples. The sampling plan or protocol must be specific and must address the statistical basis or technical rationale for the sampling pattern and quantity of samples selected for analysis.

Completeness - This is a definition of the measure of the amount of valid, usable data obtained from a measurement system, either field or laboratory, compared to the amount expected from the system. Data that has not been lost as a result of sampling or analysis operations or have not been rejected due to associated QC data are considered valid and usable. Usable data points may be qualified based on associated QC data. The completeness goal establishes the minimum amount of data required to reach a valid decision. A target of 90 percent completeness of field and laboratory measurements has been established for this program.

Comparability - Expresses the confidence with which one data set can be compared to another. Use of appropriate sampling and preservation methods, chain-of-custody procedures, standard analytical methods and uniform reporting units and formats will provide the basis for comparability of project data.

Timeliness - Establishes the maximum time limit required for completion of various aspects of the data collection process.

Statistical Confidence - Is a measure that is used to show how closely the data quality indicators relate to the DQOs.

A summary of the data quality objectives for the analytical procedures expected to be performed during this program is provided in Table A7.3.1. The data quality objectives shown in this table have been derived from published EPA data where available. The objectives will apply to the laboratory control sample and duplicate to be analyzed with each group of samples. These limits should also be used as a benchmark for evaluating the matrix spike/matrix spike duplicate data. Matrix spikes and duplicates that do not meet these criteria should be investigated; options for corrective action include reanalysis or re-preparation and reanalysis to determine whether an actual matrix effect is impacting recovery. If no obvious analytical problem is identified, associated data must be flagged to indicate reported results are estimated. A discussion of matrix spike/matrix spike duplicate results and the corrective action taken must be included in the data package narrative.

Measurement Performance Criteria

The measurement performance criteria for the quality objectives for mercury analysis of the Ontario Hydro samples and the coal analyses are presented in table A7.3.1.

Method detection limits for each component of the Ontario Hydro sampling train presented in Table A7.3.1. Detection limits are influenced by sample matrix, required dilutions, and interference corrections. Detection limits will be provided on the final data sheets and tables reporting the data. These detection limits will then accurately reflect the analytical conditions. Equations will also be provided to show how the detection limits were calculated.

Table A7.3 1QA Objectives For Accuracy, Precision, Completeness And Method Detection Limits				
Measurement (parameter)	**Accuracy %**	**Precision %**	**Completeness %**	**Anticipated Detection Limits**
Ontario Hydro Method Fractions				
Probe - Filter	75 - 125%	±25	90	0.05 µg
KCl Solution	75 - 125%	±25	90	0.04 µg
HNO_3/H_2O_2 Solution	75 - 125%	±25	90	0.04 µg
Knockout	75 - 125%	±25	90	0.01 µg
$KMNO_4$ Solution	75 - 125%	±25	90	0.1 µg
Hydroxylamine rinse	75 - 125%	±25	90	0.1 µg
Total Train Sample	75 - 125%	±25	90	0.34 µg
EPA Method 29/PM Analysis				
Probe - Filter	75 - 125%	±25	90	
	75 - 125%	±25	90	
	75 - 125%	±25	90	
	75 - 125%	±25	90	
	75 - 125%	±25	90	
	75 - 125%	±25	90	
Other Methods				
O_2 Method 3B Orsat	90 - 110%	±0.2	90	0.2% absolute
CO_2 Method 3B Orsat	90 - 110%	±0.2	90	0.2% absolute
Moisture Method 4	NA	–	90	0.1 gm H_2O collected
Flue Gas Velocity Method 2	NA	–	90	0.005 in H_2O)P

SPECIAL TRAINING REQUIREMENTS AND CERTIFICATION

Purpose/Background

The purpose of this element is to ensure that any specialized training requirements necessary to complete the project are known and furnished and the procedures are described in sufficient detail to ensure that specific training skills can be verified documented and updated as necessary.

Training

No additional specific training is required for the conduct of this test program. All emissions test team members are experienced in the conduct of the required test methods.

All team members have had 40 hour OSHA training and yearly 8-hour refresher courses on source sampling safety.

Certification

No certifications, other than the OSHA training is required.

DOCUMENTATION AND RECORDS

Purpose/Background

This element defines which records are critical to the project, are to be archived and are to be included in the test report documents. The data-reporting format and document control procedures are delineated.

Information Included in the Reporting Packages

This section of the QAPP identifies records and information to be included in the report documents. Reporting format is also described as well as document control procedures for data and reports

Field Operation Records

The field operation records will include:

- All isokinetic sampling train operation data sheets.
- All setup and recovery sheets.
- Preliminary flue gas velocity traverses.
- Method 3B Orsat Analysis data sheets.
- Daily log of activities.
- Field isokinetic ratio calculations.
- Chain of Custody Sheets for train lab setup, transport to sampling location and setup, run operation, transport to recovery lab and recovery.
- Plant Data Acquisition System operations printout, discs.
- Signature of the person collecting the data.
- Field Laboratory notebook.
- QA/QC activities log and corrective action reports (if any).

Laboratory Records

The analytical laboratory records will include:

- Laboratory analytical report sheets and back up documentation for each analysis performed.
- The results of all QA/QC activities to include analysis of performance samples, blanks, matrix spike, matrix spike duplicates, duplicate analyses and corrective action reports.
- All raw analytical data, including instrumentation printouts, bench sheets and laboratory notebook pages.
- Chain of Custody record from receipt of samples through analysis and disposition.
- Sample preparation information
- Calibration records.
- Narrative for preparation of calibration standards, samples and QA/QC samples.
- Sample calculations for each analysis performed.

- Narrative addressing any modifications to sample preparation and analytical methodologies.

Data Handling Records

Data handling records will include the protocol and spread sheets used in data reduction, verification and validation.

Data Reporting Package and Documentation Control

Data Reporting package

All field data will be recorded in ink on the respective method data sheets. All corrections will be crossed out, initialed and dated. At the conclusion of each test run, the field team leader will review all data sheets for completeness, accuracy of data recording, other errors. The person originating the data sheet will correct noted omissions, errors, etc. All field calculations and final reduced data and tables will be performed via computer spreadsheets, which will be presented in both electronic copy on disc and hard copy. The reporting package will consist of all items described in Section A9.2.2.

These items will constitute several appendices in the test report.

Documentation Control

During the conduct of the field phase of the program, all completed data sheets, plant data acquisition system (DAS) printouts, field notes are maintained in three ring binders. These binders and laboratory notebooks are maintained in the onsite field laboratory filing cabinet, when not being utilized. This laboratory is locked when no one is present inside. At the completion of the testing, the files are transferred to the Field Team Leader for transport to the TRC offices. The working files are stored in the Program Managers Office file area. All TRC personnel will have access to these files; the program manger will be responsible for keeping track of the files removed from the file area.

Data Reporting Package Archiving and Retrieval

Working files will be stored in the TRC Program Manager's file area. At the completion of the program, the files will be transferred to storage boxes and placed in the TRC Records Retention Center. The archived material is retrieved from the Center by submitting a file request form to the Records Retention person. The file is signed for on receipt and is signed back in upon completion of use.

All documentation, including the QAPP, SSTP, Final Test Report, all raw field data, analytical laboratory data packages, field and laboratory notebooks, and logbooks will be maintained in the stored program file by TRC for a minimum of five years after completion of the test program. Analytical laboratories will maintain the data file according to their standard operating procures.

MEASUREMENT/DATA ACQUISITION

SAMPLING PROCESS DESIGN (EXPERIMENTAL DESIGN)

Purpose/ Background

This section of the QAPP covers all aspects of measurement system design and implementation, ensuring that appropriate methods for sampling, analysis data handling and QC are employed.

Scheduled Project Activities Including Measurement Activities

The sampling program is to commence subsequent to the approval of the QAPP and SSTP by ADA Environmental Solutions. All final reports will be submitted to ADA Environmental Solutions within 90 days of completion of the testing.

This QAPP is generic for the Mercury Emissions Sampling program to be conducted at Salem Harbor Generating Station, Unit 1. Specific schedule for Unit 1 will be included in the Site Specific Test Plan.

Rationale for Design

ADA Environmental Solutions, under contract from Department of Energy, has delineated the test requirements for this program. Unit 1 will be tested as described in the SSTP. Mercury emissions will be determined concurrently via the Ontario Hydro method at the inlet and outlet of the final control device of the given unit. A test will consist of conducting three test runs between 2-3 hours duration in order to obtain collected mercury above the MDL for each fraction of the sampling train

Design Assumptions

The following assumptions were made in designing the sampling program:

- Three test runs for mercury are to be conducted at the inlet and outlet of the final pollution control system. It is deemed by ADA that this will be sufficient to provide the required data.
- The test runs will be of 2-3 hour durations in order to collect mercury species above the MDL for each fraction with a sample volume not to exceed 2.5 dscm.
- During testing Unit 1 will operate at near maximum load.
- Isokinetic sampling across the sampling planes will eliminate any particulate stratification problems due to gas flow pattern anomalies.
- Elemental vapor mercury is not stratified in the gas stream.

11.
12.

13.

Procedures for Locating and Selecting Environmental Samples

Unit 1 Salem Harbor

The sampling locations for Unit 1 Salem Harbor were determined by ADA during the initial site survey. The following sections present descriptions of the emission and process sampling locations.

ESP Inlet Location

As shown in Figure B1-1, there are two horizontal inlet ducts, designated as A (east) and B (west). There are three (4-inch ID) sample ports located on top of each inlet duct. Each duct is 54 inches by 114 inches. The test ports on Duct A are located approximately 330 inches (4.5 duct diameters) downstream and approximately 131 inches (1.8 duct diameters) upstream of the nearest flow disturbance. The test ports on Duct B are located approximately 340 inches (4.6 duct diameters) downstream and approximately 114 inches (1.6 duct diameters) upstream of the nearest flow disturbance. The ports do not meet the minimum distance requirements of EPA Method 1. There is no other point of access prior to the ESP, which met the Method 1 minimum distance requirements; therefore the existing sample ports were utilized during the test program. TRC utilized 24 traverse points (3 x 8) within each air pre-heater exhaust. The sampling point locations are presented in Table B1-1.

ESP Exhaust Sampling

The emissions from Unit 1 are discharged to an exhaust stack that is 445 feet tall. The sampling locations are 205 feet above grade with a permanent test platform, which is accessed via an elevator. As shown in Figure B1-2, the exhaust stack has an inside diameter of 108 inches. Four 6-inch ports, located 90E apart on the same plane, are present on the stack. These ports are located 210 feet (23.3 stack diameters) downstream of the nearest disturbance and 250 feet (27.8 stack diameters) below the stack exhaust.

In accordance with EPA Method 1, TRC conducted a 16-point traverse (8-points on each diameter, 4 points per port) during each test run. Table B1-2 presents these traverse points.

Table B1-1 ESP Inlet Duct Traverse Sampling Points

Point	Distance from Wall, Inches
1	7.1
2	21.4
3	35.6
4	49.9
5	64.1
6	78.4
7	92.6
8	106.9

Table B1-2 ESP Exhaust Traverse Sampling Points

Point	Percent of Stack Diameter	Distance From Wall (in.)
1	3.2	3.5
2	10.5	11.3
3	19.4	21.0
4	32.3	34.9

Classification of Measurements as Critical or Non Critical

All field measurements and laboratory analyses to be conducted are considered critical to the project.

Validation of any Nonstandard Methods

The draft Ontario Hydro Method for the determination of Mercury emissions, designated Pre-003 by the EPA, OAQPS, EMC, has been subjected to Method 301 validation.

Figure B1-1. Unit 1 ESP Inlet Sampling Location Schematic

(figure not available)

Figure B1-2 PG&E NEG Salem Harbor Generation Station Unit 1 Outlet

(figure not available)

SAMPLING METHODS REQUIREMENTS

Purpose/Background

This section delineates the sampling and analytical methods to be utilized in the test program. ADA has prepared a site-specific test plan that documents in detail all sampling and analytical procedures to be utilized at Unit 1, Salem Harbor. The relevant sections of the SSTP where this information can be found are presented in the subsections below.

Sample Collection, Preparation and Decontamination Procedures

Salem Harbor Unit 1

The sampling and analytical methods to be utilized in this program are delineated below:

Emissions Testing

- EPA Method 1 - 40CFR60 Appendix A, Sample and Velocity Traverses for Stationary Sources.
- EPA Method 2 - 40CFR60 Appendix A, Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube).
- EPA Method 3B - 40CFR60 Appendix, Gas Analysis for The Determination of Emission Rate Correction Factor or Excess Air.
- EPA EMC-Pre-003, Draft Standard Test Method for Elemental, Oxidized, particle Bound and Total Mercury Emissions in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).

Table B2-1 presents the sampling and analytical matrix at each location. Table B2-2 shows all of the measurements being made at each test location.

Emission Sampling Activities

Emission sampling activities will include equipment set up and conducting simultaneous testing of the inlet duct and the ESP exhaust duct.

B2.2.1.1.1 EPA Methods 1 and 2 for Velocity Measurements and Cyclonic Flow

Velocity traverses will be conducted at all sampling locations with an S-type pitot assembly in accordance with 40 CFR Part 60, Appendix A, Method 1, "S*ample and Velocity Traverses for Stationary Sources"* and Method 2 "D*etermination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)".* An S-type pitot tube with an attached inclined manometer will be used to measure the gas velocities. An attached Type-K thermocouple with a remote digital display will be used to determine the flue gas temperature. During the test program, velocity

Table B2-1 Pg&E Neg Salem Harbor Station Test Matrix For Unit 1

Sampling Location	Sample/ Type Pollutant	Sampling Method	No. of Trains at Location	No. of Runs Per Train	Sample Run Time (min)	Analytical Method	Analytical Lab
East Inlet to the ESP	Mercury speciated	Ontario Hydro (includes EPA M1, 2 & 4)	1	3	120-180	Ontario/Hydro & SW846, 7047A, CVAA	Philip Analytical Services
	O_2/CO_2	M3A (Bag)	1	3	120-180	3A CEMS	TRC
East Outlet to 2nd ESP	Mercury Speciated	Ontario Hydro (includes EPA M1, 2 & 4)	1	3	120-180	Ontario/Hydro & SW846, 7470A, CVAA	Philip Analytical Services
	Multi-Metals/PM	M29	1	3	120-180		
	O_2/CO_2	M3A (Bag)	1	3	120-180	3A CEMS	TRC

Table B2-2 Measurements Conducted At Each Test Location For Unit 1

East ESP Inlet	East Exhaust to 2nd ESP	Process
EPA-EMC - Pre-003 Speciated Mercury - Ontario Hydro	EPA-EMC - Pre-003 Speciated Mercury - Ontario Hydro Multi/Metals-PM (EPA 29)	Fuel Sample
O_2/CO_2 (M3A)	O_2/CO_2 (M3A)	
Sampling Location & Traverse Points (M-1)	Sampling Location & Traverse Points (M-1)	
Velocity (M-2)	Velocity (M-2)	
Moisture (M-4)	Moisture (M-4)	

measurements will be conducted during each test run at each sampling location. The required number of velocity measurement points for each sampling location will be determined following EPA Method 1.

Cyclonic flow checks will be conducted at each sampling location prior to sampling in accordance with Section 2.4 of EPA Method 1. This procedure is referred to as the nulling technique. An S-type pitot tube connected to an inclined manometer will be used in this method. The pitot tube will be positioned at each traverse point so that the face openings of the pitot tube were perpendicular to the stack cross-sectional plane. This position is called the "0º reference". The velocity pressure (ΔP) measurement will be noted. If the ΔP reading is zero, the cyclonic angle will be recorded as 0º. If the ΔP reading is not zero, the pitot tube will be rotated clockwise or counter clockwise until the ΔP reading became zero. This angle will then be measured with a leveled protractor and reported to the nearest degree. After this null technique is applied at each traverse point, the average of the cyclonic angles will be calculated. If this average is less than 20º, the flow condition in the source will be acceptable to test.

B2.2.1.1.2 EPA Method 4 for Moisture

Moisture will be determined for each test run according to EPA Reference Method 4, "*Determination of Moisture Content in Stack Gases"*, as an integral part of the Ontario Hydro Method. The principle of this method is to remove the moisture from the sample stream and determine the moisture either volumetrically or gravimetrically.

Prior to the test program, a preliminary Method 4 will be conducted at each sampling location to determine moisture and allow for the calculation of isokinetic sampling ratios. This sampling train uses a glass lined probe with a thermocouple and S-type pitot tube attached to the probe for the measurement of gas temperature and velocity. The sample gas passes through a series of four ice-cooled impingers kept below 68ºF to enable condensation of entrained moisture. The first two impingers contain 100 mL of deionized water. The third impinger is empty and the fourth impinger contain a preweighed amount of silica gel. A dry gas meter, pump, and calibrated orifice meter follow the impingers. All impingers will be weighed prior to the setup of the train.

Leak checks of the entire Method 4 sampling trains will be performed before and after each sampling run. All leak checks and leakage rates will be documented on the relevant field test data sheet. The acceptance criterion for the Method 4 train is a leak rate of ≤ 0.02 cfm at the highest vacuum obtained during the run.

Following the completion of the preliminary test run, the Method 4 train will be transported to a recovery area onsite. The sample recovery sequence will be as follows:

- Removed the sampling train to the recovery area;
- Note the condition of the train (i.e., impinger contents color, silica gel color, etc.); and
- The final weights of all impingers will be obtained.

B2.2.1.1.3 Ontario Hydro Mercury Speciation Train (EPA EMC Pre-003)

Speciated mercury (Hg) will be determined at the ESP inlets and the ESP exhaust for Unit 1 via EMC Pre-003 "*Draft Standard Test Method for Elemental, Oxidized, Particle Bound, and Total Mercury Emissions in the Flue Gas Generated From Coal Fired Stationary Sources (Ontario Hydro Method)"*. The description of the sampling and analytical methodology in this section is based on the draft method released October 27, 1999.

The sampling train utilizes the EPA Method 17 sampling configuration and consists of a Teflon coated button-hook nozzle, Teflon coated filter housing, and Teflon-lined probe. A thermocouple and S-type pitot tube will be attached to the probe for the measurement of gas temperature and velocity. The ESP inlet and the ESP exhaust sampling locations require that the probe be in a vertical sampling configuration as shown in Figure B2-1.

The sample gas passes through the nozzle assembly to a tared glass fiber filter, on a Teflon filter support, contained in a Teflon coated filter holder. The nozzle and the gases entering the filter holder are maintained at either the stack temperature ± 21ºF. Downstream of the filter and the teflon sample line the sample gas passes through a series of eight ice bath cooled impingers, kept below 68ºF to enable condensation of entrained moisture and the gases mercury species. The first, second and third impingers each contain 100 mL of 1N KCl solution. The fourth impinger will contain 100 mL of a 5% HNO_3/10% H_2O_2 solution. The fifth, sixth, and seventh impingers will each contain 100 mL of a 4% $KMnO_4$/10% H_2SO_4 solution. The eighth impinger will contain 200 - 400 gms of silica gel. All filled impingers are weighed prior to placing the impingers in the train. The impingers are followed by a leak free pump, dry gas meter and calibrated orifice meter.

The first, second, fourth, six and eighth impingers are of the Modified Greenburg design. The third and seventh impingers are standard Greenburg Smith impingers. No silicone grease will be used in the train.

Three test runs of 144 minutes duration, with a sample volume of between 35.31 and 88.25 dscf (1-2.5 dscm) collected, will be conducted at each location simultaneously. Sampling will be isokinetic (±10%). All stack and train operating parameters will be recorded at each sampling point.

Figure B2-1 ESP Exhaust Sampling Location

(figure not available)

Following the completion of each test run, the Ontario Hydro train will be transported to a recovery area onsite. The sample recovery sequence is as follows:

- All openings on the probe, inlet to cyclone/or filter holder and impingers are sealed with teflon tape.

- Remove the sampling train to the recovery area.

- Note the condition of the train (i.e., filter, impinger contents color, silica gel color, etc.).

- Container No. 1 - Disassemble the filter housing and transfer the filter to its original glass container. Seal the petri dish with Teflon^R tape and label it with the appropriate sample information. Any filter fibers adhering to the support gasket will be transferred to the petri dish.

- Container No. 2 - The front half of the train, nozzle, probe, and front-half filter housing, cyclone and flask are then brush-rinsed with 100 mL of 0.1N nitric acid into an amber glass container with a Teflon^R-lined cap. The container is sealed and labeled.

- Container No. 3 - The contents of the first three KCl impingers are weighed. The filter support, backhalf of the filter holder and connecting glassware are rinsed with a 0.1 N HNO_3 into a glass amber container with a teflon lined cap. The 5% $KMNO_4$ solution is added to each impinger until a purple color remains. The solutions are then poured into the container. Rinse the impingers and connecting glassware with 10% HNO_3. Although unlikely, if deposits remain on the impinger surfaces, remove them by doing another 10% HNO_3 rinse that has a very small amount (several drops) of 10% hydroxylamine sulfate solution added to each of the KCl impingers. Add these rinses to Container 3. If the solution in Container 3 becomes clear, add a small amount of the 5% $KMnO_4$ solution until a pink or slightly purple color is obtained. Check again after 90 min to ensure the purple color remains. Perform a final rinse of the impingers and connecting glassware with 0.1 N HNO_3, and add to Container 3. The container is sealed and labeled.

- Container No. 4 - The contents of the fourth impinger is weighed and transferred to a glass container with a Teflon^R-lined cap. The impinger and U-tubes are rinsed twice with 3-25 mL portions of 0.1N nitric acid into a sample container. The container is sealed and labeled.

- Container No. 5 (Impingers 5 through 7, H_2SO_4 - $KMnO_4$ Impinger Contents and Rinses) - Dry the exterior surfaces of Impingers 5, 6, and 7. Then weigh and record the weight of each impinger (to the nearest 0.5 g). Pour all of the liquid from the three H_2SO_4-$KMnO_4$ impingers into a glass sample Container 5. Rinse the impingers and connecting glassware twice with 0.1 N HNO_3. If deposits remain on the impinger surfaces, after the two rinses, remove them by doing a third rinse with 0.1 N HNO_3 and several drops hydroxylamine sulfate. On a drop by drop basis add more hydroxylamine sulfate until the deposit are removed. Add these rinses to Container 5. If the solution in Container 5 becomes clear, add small amounts of H_2SO_4-$KMnO_4$ solution until a pink or slightly purple color is obtained.

Perform a final 0.1 N HNO_3 rinse of the impingers and connecting glassware follow by a water rinse. The 0.1 N HNO_3 rinse is added to Container 5, and the water rinse is discarded. Mark the height of the fluid level, seal the container, and clearly label the contents.

- The silica gel impinger is weighed to obtain a final weight.

- Solution Blanks (Containers 6-10) - Solution blanks are taken each time new reagents are prepared.

- Container 6 - (0.1 N HNO_3 Blank) - Place 50 mL of the 0.1 N HNO_3 solution used in the sample recovery process into a properly labeled container. Seal the container.

14.

- Container 7 (1 N KCl Blank) - Place 50 mL of the 1 N KCl solution used as the impinger solution into a properly labeled container. Seal the container.

- Container 8 (5% HNO_3 - 10% H_2O_2 Blank) - Place 50 mL of the HNO_3-H_2O_2 solution used as the nitric acid impinger reagent into a properly labeled container. Seal the container.

- Container 9 (H_2SO_4 - $KMnO_4$ Blank) - Place 50 mL of the H_2SO_4 - $KMnO_4$ solution used as the impinger solution in the sample recovery process into a properly labeled container. Refer to Note 4 in Section 13.2.10.5 of this method.

- Container 10 (10% Hydroxylamine Sulfate Blank) - Place 100 mL of hydroxylamine sulfate solution into a properly labeled sample container. Seal the container.

- Container 11 (Sample Filter Blank) - Once during each field test, place into a properly labeled petri dish three unused blank filters from the same lot as the sampling filters. Seal the petri dish.

- All containers are checked to ensure proper sealing, proper labeling, and that all liquid levels are marked. All samples are logged onto a chain-of-custody record.

The Ontario Hydro train will produce the following samples:

- Container No. 1 - Filter
- Container No. 2 - Front-Half 0.1N HNO_3 Rinse
- Container No. 3 - Impingers 1, 2 & 3 KCl Impinger Catch & Rinse
- Container No. 4 - Impinger 4 - 0.1N HNO_3 Impinger Catch & Rinse
- Container No. 5 - Impingers 5 - 7 - $KMnO_4$ Impinger Catch & Rinse

B2.2.1.1.4 O_2 and CO_2

The O_2 and CO_2 concentration in the integrated bag sample will be analyzed onsite within 4 hours of completion of the run with an Orsat analyzer as per Method 3B. Three or more passes will be made until 3 results are within 0.2% (absolute) of each other.

Support Facilities for Sampling

The laboratory selected to conduct the analyses, Philips Analytical Services; Canada has the capabilities of attaining the analytical and method detection limits of the methods.

The sampling equipment required for the completion of the emission testing will be mobilized from TRC's Lowell, MA office.

Sampling /Measurement System Failure Response and Corrective Action Process

The acceptance limits for the sampling and analyses to be conducted in this program will be those stated in the method. The corrective actions are likely to be immediate in nature and most often will be implemented by the analyst, field team leader or appropriate QA manager; the corrective action will usually involve recalculation, reanalysis, or repeating a sample run. TRC's ongoing corrective action policy is described here.

Immediate Corrective Action

Specific QC procedures and checklists are designed to help field team members and analysts detect the need for corrective action. Often the person's experience will be even more valuable in alerting the operator to suspicious data or malfunctioning equipment.

If a corrective action can be taken at this point, as part of normal operating procedures, the collection of poor quality data can be avoided. Instrument and equipment malfunctions are amenable to this type of action and TRC's QC procedures include troubleshooting guides and corrective action suggestions. The actions taken should be noted in field or laboratory notebooks but no other formal documentation is required, unless further corrective action is necessary. These on-the-spot corrective actions are in every part of the QA/QC system.

Corrective action during the field sampling portion of a program is most often a result of equipment failure or an operator oversight and may require repeating a run. When equipment is discovered to be defective (i.e., failure of pre- and post-sampling leak checks) it is repaired or replaced and a correction factor is established as per the EPA method. If a correction factor is unacceptable the run is repeated. Operator oversight is best avoided by having field crewmembers audit each other's work before, during and after a test. Every effort is made by the field team leader to ensure that all QC procedures are followed. Economically, it is preferred to repeat a run during a particular field trip rather than return at a later date.

Corrective actions for analytical work would include recalibration of instruments, reanalysis of known QC samples and, if necessary, of actual field samples.

If the problem is not solved in this way, more formalized long-term corrective action may be necessary.

Long-Term Corrective Action

The need for this action may be identified by standard QC procedures, control charts, performance or system audits. Any quality problem that cannot be solved by immediate corrective action falls into the long-term category. TRC uses a system to ensure that the condition is reported to a person responsible for correcting it who is part of the closed-loop action and follow-up plan.

The essential steps in the closed-loop corrective action system are:

- Identify and define the problem.
- Assign responsibility for investigating the problem.
- Investigate and determine the cause of the problem.
- Determine a corrective action to eliminate the problem.
- Assign and accept responsibility for implementing the corrective action.
- Establish effectiveness of the corrective action and implement it.
- Verify that the corrective action has eliminated the problem.

Documentation of the problem is important to the system. A Corrective Action Request Form (shown in Figure B2-3) is filled out by the person finding the quality problem. This form identifies the problem, possible causes and the person responsible for action on the problem.

The responsible person may be an analyst, field team leader, department QC coordinator or the QA Officer. If no person is identified as responsible for action, the QA Officer investigates the situation and determines who is responsible in each case.

The Corrective Action Request Form includes a description of the corrective action planned and the date it was taken, and space for follow-up. The QA Officer checks to be sure that initial action has been taken and appears effective and, at an appropriate later date, checks again to see if the problem has been fully solved. The QA Officer receives a copy of all Corrective Action Forms and then enters them in a Corrective Action Log. This permanent record aids the QA Officer in follow-up and makes any quality problems visible to management; the log may also prove valuable in listing a similar problem and its solution. Copies of Corrective Action forms pertinent to this program will be included in the Final Report.

Sample Preservation, and Holding Time Requirements

The recovered fractions sample bottles of the Ontario Hydro Sampling Train will be kept on site in coolers. The sample bottles will preserved in accordance with method procedures. The holding time for the Ontario Hydro Method Samples from sampling to analysis is 28 days. There are no preservation or holding time requirements for the coal samples. However, the digestate should be analyzed within 28 days of preparation.

FIGURE B2-3 CORRECTIVE ACTION REQUEST FORM

Corrective Action Request Form No.

Originator: Date:

Person Responsible For Replying: Contract Involved:

Description of problem and when identified:

State cause of problem, if known or suspected:

Sequence of Corrective Action: (If no responsible person is identified, notify QA Manager immediately. Submit all CA forms to QA manager for initial approval of CA.)

State Date, Person, and Action Planned:

CA Initially Approved By: Date:

Follow-Up Dates: Date:

Information Copies to:

RESPONSIBLE PERSON/
DEPARTMENT QC COORDINATOR:
QA MANAGER:
DEPARTMENT MANAGER:

SAMPLE HANDLING AND CUSTODY REQUIREMENTS

Purpose/Background

This element of the QAPP describes procedures used to maintain sample integrity during all phases of sample handling and analysis. A written record is kept of sample handling activities.

Sample Custody Procedure

Introduction

The purpose of sample traceability procedures is to document the identity of the sample and its handling from its first existence as a sample until analysis and data reduction are completed. Custody records trace a sample from its collection through all transfers of custody until it is transferred to the analytical laboratory. Internal laboratory records then document the custody of the sample through its final disposition.

Sample integrity will be maintained throughout all sampling and analysis programs. In accordance with SW-846, a sample is considered to be under a person's custody if the sample is:

- In that person's physical possession
- In view of that person after acquiring possession
- Secured by that person so that no one can tamper with the sample
- Secured by that person in an area which is restricted to authorized personnel

These criteria will be used to define the meaning of "custody" and ensure the integrity of the test program samples from collection to data reporting. Limited access to the samples is an integral part of the chain-of-custody procedure.

Samples will be held within sight of the samplers or sample custodian, or will be kept in sealed or secured containers at all times. Sealed containers will be used to ship samples to the appropriate laboratory.

Chain-of-Custody Documentation

Labeling

Sample identification labels are used by TRC to ensure that the required information is entered in the field. When sample batches are shipped to the specified laboratory, a chain of custody form accompanies the shipment. This form is based on established laboratory format and will be used to document sample transfer in the field and from sampling personnel to the laboratory.

TRC's laboratory sample recovery chemist will coordinate the packing and shipment of all samples. Worksheets specifically designed for this program will be generated prior to the field effort. These sheets will assist the Field Team Leader in assuring all samples have been collected, accounted for, and shipped under sample traceability documentation to the appropriate laboratory.

Sample container labels will be affixed to the sample containers prior to or at the time of sampling. Sample labels will be affixed to each appropriate container for process samples at the time of collection. Exhaust gas samples labels will be affixed to the appropriate container at the time of sample recovery. All samples collected during the test program will be labeled following the designated code system stated in Section 6 of the SSTP. Each sample label is preprinted prior to the test program. Each label will contain the following information:

- Sample Identification Number
- Date of Collection (recorded at the time of collection/recovery)
- Initials of sample collector (recorded at the time of collection/recovery)
- Matrix type
- Analytical Method
- Type of preservation used, or "none" as applicable.
- Run Number
- Identification of test series

Printed sample labels will be used for identifying all samples. An example label is shown in Figure B3-1. The nomenclature for emissions samples will be as follows:

PG&E NEG – SALEM HARBOR GENERATING STATION

Code: BP-OHM-INA-1-KCl
Matrix: KCl Date: 11/ /99
Analysis: Hg Lab:
Initials: Contract:

PG&E NEG –Salem Harbor Generating Station Sampling Program
Method OHM Train, Impingers 1, 2 & 3 (KCl) Contents and Rinses - Run 1
Inlet 1

BP-OHM-*a*-*b*-*c*-Hg

where:

BP	=	Salem Harbor Generating Station
OHM	=	Ontario Hydro Method
a	=	Sample Location

where:

IN	=	ESP Inlet Unit 1 East
OT	=	ESP Exhaust East Outlet
b	=	Run Number (sequential)
c	=	Sample train fraction

where:

PF	=	Particulate Filter
FHR	=	Front Half Rinse
KCl	=	Potassium Chloride solutions Imp 1, 2, & 3
HNO_3/H_2O_2	=	Nitric Acid/Hydrogen Peroxide Solution
$KMNO_4$ =	Potassium Permangenate Solution	
Hg	=	Mercury Analysis

Figure B3-1 Example Sample Label

All hand written documentation will be in indelible ink. All labels are covered with clear tape. TRC will provide all sample containers, labels, packing materials and shipping containers.

Items such as impingers, gas sample bags (Orsat) and glass fiber filter cartridges will be labeled with tape to indicate the run number prior to sampling. If more than one train is being utilized in simultaneous testing, these train components will also be labeled to indicate the type of train and location and the labels will be keyed to specific trains (e.g., inlet OH1 or OH2). TRC also utilizes color-coding of the trains to aid in rapid visual identification. These colors are designated to each train type for the entire test period. Since samples will be recovered from each of these components immediately after the test run in the field laboratory, no additional labeling will be necessary.

Integrity Seals

Integrity seals will be placed over the top of the sample containers to detect unauthorized sample handling. Gummed labels or equivalent are acceptable for this purpose. These seals will include the following information; date and initials of the person recovering the sample.

Field Logbook

The TRC Field Team Leader will maintain a permanently bound field logbook. Information pertinent to the sampling will be recorded in a sampling log. All entries will be made in indelible ink and all corrections will follow error correction protocol of one line through the error, the initial of the person performing the correction and the date of the correction. Sampling personnel will also record all information on the appropriate sampling forms.

The following information will be included:

General Entries	Specific Entries per Test Run
Sampling	Date of Run
Installation	Start/Stop Times of each Type of Sampling Train
Facility	Process Upsets
Project Number	Delay Times
Project Manager	Orsat Analytical Data
Person receiving samples	Moisture Data

Chain-of-Custody Forms

Custody of the samples will be documented using a series of chain-of-custody forms which are shown in Appendix B of the SSTP. All chain-of-custody forms will be retained by the Laboratory Coordinator and reported in the final report.

Chain-of-Custody Procedures

Pre-sampling Procedures

TRC will purchase pre-cleaned sample bottles and containers for items such as probe washes, impinger solutions and miscellaneous source samples (e.g., ash), and additional sample bottles for QA/QC samples and blanks.

Impingers and other glassware will be cleaned and packed for shipment. After cleaning, the above items will be stored in a controlled access laboratory in the custody of an assigned individual until the shipment to the test site.

Shipment of equipment and materials will be accomplished by truck. Once onsite, all equipment and sample containers will be stored in a secure area.

On-Site Sample Train Preparation

Preparation of sampling trains is a responsibility of TRC. The onsite setup/recovery person will prepare the following for each sampling train as required:

- Reagents and liquid sampling medium
- Impingers, each appropriately labeled
- Glass fiber filter, labeled
- Gas sampling bag (Orsat), labeled

The set-up/recovery person will also enter the components of each train on the Sample Train Custody Sheet and will sign in the appropriate space for each component prepared. Each component must be included along with any labeling information.

The sampling train operators taking the sampling train to the sampling site will sign for each component received from the setup/recovery person.
If during the sampling run, any components are broken, plugged and so forth, the person who signed for the sampling train will sign in the Remarks Section whether or not the component has been removed. The onsite recovery person will prepare and list a new component. The sampling train operator receiving the new component will again sign for that new item.

Sample Recovery

The following sample recovery procedures are applicable:

When sample trains are returned from the sampling site, the onsite recovery person receiving the train will sign for each component on the Sampling Train Custody Sheet.

The sampling trains are then broken down and the various samples recovered. These samples are then recorded on the Chain-of-Custody Form. Each onsite recovery person will maintain a separate data sheet for the samples that he recovers. As each sample is recovered, the samples will be labeled and sealed.

The onsite recovery person will consolidate the samples in a designated storage area at the test site. The samples will either be in his view, or in the view of other authorized test team members, or be under lock and key until these samples are shipped to the laboratory. The samples will be shipped to the subcontractor laboratories as soon as possible.

Sample Shipment

Samples will be shipped to Philips Analytical Services, Canada by dedicated courier or air via Federal Express. Prior to shipment, the onsite recovery person will prepare a Chain-of-Custody Form for each shipping container and an air bill for each shipment. Receipt of the samples will be acknowledged by the laboratory sample custodian for hand delivery or by the shipping agent on his custody sheet. The custody sheet will be a three-part form. Two copies will be included with the shipping container and the onsite recovery person will retain one copy. Upon arrival at the laboratory facilities, the samples will be delivered to the laboratory project manager or designated agent for further distribution and analysis. The Chain-of-Custody Form will reflect all changes in custody (onsite staff to shipping agent; shipper to the laboratory facilities; laboratory facilities to laboratory personnel).

Laboratory Operations

All samples submitted to the subcontractor laboratory will be brought to the sample custodian, who will continue the traceability documentation logging the samples into a central log book and assigning laboratory sample numbers. These laboratory sample numbers will serve as a means of tracking samples through the laboratory analysis. The sample number is unique and nonrecurring. Each subcontractor laboratory maintains a secure laboratory facility. Access to laboratory operations and sample storage is possible only to employees having the proper key card or combination.
All materials such as field and laboratory notebooks and logbooks, field and laboratory data records, correspondence, reports, sample tags, traceability records and instrument printouts will be clearly labeled with the project number and become a permanent part of the project file.

Project samples will be disposed of in an appropriate manner 60 days after acceptance and approval of a final report.

Sample Inspection

When samples are received at the subcontractor laboratory, they will be brought to the sample custodian who will unpack them and immediately reconcile the sample counts with the chain-of-custody documentation. All discrepancies will be immediately reported to the Laboratory Manager who will immediately contact TRC's Laboratory Services coordinator or his backup, by telephone or by fax. In no case will this communication be delayed by more than four hours after unpacking the samples. Until discrepancies are resolved the laboratory will retain all packing materials for that sample shipment.

Shipping and Packing of Samples

All samples will be shipped under Chain-of-Custody to the analytical laboratory using the most expeditious manner possible.

Sample bottles will be wrapped in bubble wrap and placed in coolers containing crushed ice and/or "blue ice". A signed chain-of-custody form listing all samples in the cooler will be placed in the cooler and the cooler sealed with tape and custody tape.

Shipping

Shipping considerations include the following:

Separate packages will be used for each class of samples. If air shipped, all packing and labeling will conform to International Air Transport Association (IATA) regulations for air shipment.

Packing and Preservation

Note that IATA Regulations will be followed for shipment of regulated materials via Federal Express.

Pre-003 Ontario Hydro Method

The following samples will be packed into UN containers and labeled and shipped as corrosive liquid, n.o.s., UN 1760 if shipped via air. These samples will be packed and shipped chilled in the shipping container to Philip Analytical Services.

water	nitric acid rinse
nitric acid/hydrogen peroxide	sulfuric acid/potassium permanganate
hydrochloric acid	filter
potassium chloride	

The filter will be placed in a petri dish and sealed with Teflon tape and integrity seal. The dish will be placed in a Ziploc bag and then wrapped in bubble-wrap. The filter can be placed in the same shipping container with the solvents.

ANALYTICAL METHODS REQUIREMENTS

Purpose/Background

This element describes the Analytical Methodologies utilized in program.

Preparation of Samples

The fractions of the Ontario Hydro train will be collected in wide mouth amber bottles precleaned according to CLP protocol. The caps will be teflon lined. The samples will be maintained at 4□C with ice in a cooler before and during shipment. Philips Analytical Services, Canada, will analyze the samples with 28 days of sampling.

For each test series, the samples from one run will be subjected to duplicate analysis. Other analytical QC requirements include matrix spike and matrix spike duplicate, method and reagent blanks, and laboratory control sample as delineated in Table B4.3.1. The as-fired coal samples will be collected in polyethylene bags and sealed to prevent moisture loss. Except for the analysis of mercury after dissolution, the ASTM methods do not have a holding time. The mercury will be analyzed with 28 days after dissolution.

Analytical Methods

All fractions of the Ontario Hydro sample will be prepared according to Method Pre-003. The mercury contained in the Ontario Hydro Method fractions will be determined by SW846 Method 7470A, Mercury in Liquid Waste (annual Cold Vapor technique).

Oxygen and Carbon Dioxide in the flue gases will be determined by an Orsat Analyzer as per Method 3B delineated in 40CFR 60 Appendix A.

Table B4.3.1 Analytical Qc Measures

QA Measure	Minimum Frequency
Method Blank	Each sample set or every 10 samples.
Calibration Check Sample	Daily.
Duplicate Sample	One per process stream analytical parameter, where MS/MSD is not applicable.
MS/MSD	One per Ontario Hydro & process stream analytical parameters, where applicable.
LCS	One per analytical parameter
Reagent Blank	Each Sample Set

QUALITY CONTROL REQUIREMENTS

Purpose/Background

This element documents the quality controls that will be utilized during the conduct of EPA Methods 1-4, the Ontario Hydro Mercury Method, the analysis of the Ontario Hydro fractions, and coal.

QC Procedures

The analytical QC requirements for the mercury analysis by EPA SW846 7470A and 7471A are presented in Table B5.2.1. These will be the QC requirements for ASTM D3684. The field measurements QC checks are delineated in Section 6.0 of the SSTP. They include calibrations, train leak checks, use of standardized data sheets, dry gas meter and orifice meter QA credits.

Table B5.2.1 Summary QA/QC Criteria for Mercury (7470A, 7471A)

Quality Parameter	Method/Frequency	REF	Criteria
Demonstrated Ability	LCS	7470A	80% - 120%
Field Blanks	1 per field test	QA/QC	< Reporting limit
Lab Blanks	Calibration Blank Method Blank	7470A	< Reporting limit
Initial Calibration	Calibration Blank + Five Standards	7470A	r > 0.995
Continuing Calibration	Midpoint Standard - Every 10 samples	7470A	± 20%
Precision and Accuracy	1 LCS per batch	7470A	80% - 120%
	MS/MSD per Batch	7470A	70% - 130% Recovery ± 25% RPD
Continuing Accuracy Check	Instrument Calibration Verification ICV	7470A	80% - 120%
Verification	ICV	Lab SOP	Different Source/Lot
Detection Limit	Aqueous Samples Solid Samples	7470A 7471A	0.0002 mg/L (Air Matrix (mg)) 0.01 ug/g (Coal (mg/kg))
Holding Time	Aqueous	7470A	28 Days

INSTRUMENT/EQUIPMENT TESTING, INSPECTION, AND MAINTENANCE REQUIREMENTS

Purpose/Background

The purpose of this QAPP element is to document the procedures used to verify that all equipment is maintained in sound operating condition and can operate at required performance levels.

Testing, Inspection and Maintenance

TRC and its analytical laboratory will follow an orderly program of positive actions to prevent the failure of equipment or instruments during use. This preventive maintenance and careful calibration helps to assure accurate measurements from field and laboratory instruments.

All equipment that is scheduled for field use is cleaned and checked prior to calibration. Once the equipment has been calibrated, sample trains are assembled and leak checked in order to reduce problems in the field. An adequate supply of spare parts is taken in the field to minimize downtime for any equipment failure. Table B6-1 summarizes maintenance procedures and their frequency for field sampling equipment.

The analytical laboratory will follow the equipment manufacturer guidelines for preventative maintenance. The maintenance and corrective actions will be documented in the laboratory data report.

Table B6-1 Maintenance Procedures And Frequency For Field Sampling Equipment

EQUIPMENT	MAINTENANCE PROCEDURE/FREQUENCY	SPARE PARTS
Vacuum System	Before and after field program: • Leak check. • Vacuum gauge is functional. • Check oil and oil jar. 15. Yearly or as needed: • Replace valves in pump.	Spare fluid
Incline Manometer	Before and after each field program: • Leak check. • Check fluid for discoloration or visible matter. 16. Yearly or as needed: • Disassemble and clean. • Replace fluid.	Spare fluid, O-rings
Dry Gas Meter	Before and after each field program: • Check meter dial for erraticrotation. 17. Every 3 months: • Remove panels and check for excessive oil or corrosion. • Disassemble and clean.	
Nozzles	Before and after each test: • No dents, corrosion or other damage. • Glass or quartz nozzles, check for chips and cracks.	
Diaphragm Pump	Before and after each test: 1) Leak check. Change diaphragm if needed.	
Orsat Analyzer	Before each test: • Leak check. • Inspect for damage.	Reagents, Reservoirs
Tedlar Bags	Before each test: • Leak check. • Inspect for damage.	
Miscellaneous		Fuses, fittings, Variable trans-formers.
Type “S” Pitot tubes	Before and after each: • Inspect for damage of the sensing openings. • Inspect for correct configuration on probe.	Fittings
Windtunnel	Before each calibration: • Confirm aerial flow pattern - adjust if needed.	

INSTRUMENT CALIBRATION AND FREQUENCY

Purpose/Background

This QAPP element is concerned with the calibration requirement of the field and analytical equipment.

Calibration Methods for each Field Instrument (Field and Laboratory)

An important aspect of pre-sampling preparations is the inspection and calibration of the equipment. Equipment is inspected for proper operation and durability prior to calibration. Calibration of the following equipment is conducted in accordance with the procedures outlined in the EPA document entitled *"Quality Assurance Handbook for Air Pollution Measurement Systems; Volume III -- Stationary Source Specific Methods,"* (EPA-600/4-77-027b) and 40 CFR Part 60. All calibrations will be performed prior to and at the conclusion of the Test Program. Documentation of all pretest calibrations will be kept in the project file during the field efforts. The calibration procedures for the following equipment are summarized below.

- Probe Nozzles (QA Handbook, Vol III, Section 3.4.2, pp. 19) - are calibrated on the setup days with a caliper; average of three internal diameter measurements of the nozzle; difference between high and low 0.1 mm. Recalibrate, reshape and sharpen when nozzle becomes nicked, dented or corroded. The caliper is calibrated against a NIST standard once a year.

- Pitot tubes (QA Handbook Vol III, Section 3.1.2, pp. 1-13) - measured for appropriate spacing and dimensions and may be calibrated in probe configuration in a wind tunnel. Rejection criteria given on the calibration sheet. A Post-test check will inspect for damage.

- Thermocouples (QA Handbook, Vol III, Section 3.4.2, pp. 12-18) - verified against a mercury-in-glass thermometer at three points including the anticipated measurement range. Acceptance limits - impinger ± 2ºF; dry gas meter ± 2ºF; stack ± 1.5 percent of absolute stack temperature.

- Electronic thermocouple readouts are calibrated against an Omega EC23A temperature calibrator with a tolerance of ±0.5ºF, this unit is calibrated against NIST standards once a year.

- Orifice meter - calibrated against a wet test meter at 5 H settings (flow rates) acceptance - ΔH 0.2 from average value.

- Dry gas meters (EPA 40 CFR Part 60, Method 5, Section 5.3) - calibrated against a wet test meter. Acceptance criteria - pretest $Y_i = Y \pm 0.02$; post test $Y_i = Y \pm 0.02$.

- The wet test meter is calibrated against a spirometer once a year.

- Field barometer (QA Handbook, Vol III, Section 3.4.2, pp. 18-19) - compared against a mercury-in-glass barometer or use Airport Station BP and correct for elevation. Acceptance criteria - ± 0.02 in. Hg; post-test check will be the same.

- Analytical balances (QA Handbook, Vol III, Section 3.4.2, pp. 19) - Acceptance criteria - calibrate with Standard Class-S weights within ± 0.5 g of stated value. Corrective action: Have manufacturer recalibrate or adjust.

Other laboratory calibration requirements are presented below:

Analysis/Instrument	Calibration Requirements
Analytical balances	• Annual service and calibration by manufacturer or authorized service. • Daily calibration using Class C or S Traceable weights. All service, calibration checks documented in instrument log.
Thermometers	• Calibrate annually against NIST certified thermometer.
Micropipets	• Check calibration gravimetrically at least quarterly.
Syringes, Volumetric Glassware	• Only Class A glassware to be used in sample/reagent preparation. • Analyst training to include proper handling/maintenance of volumetric glassware. • Check calibration gravimetrically if there is any question regarding the accuracy of measurement.

INSPECTION/ACCEPTANCE REQUIREMENTS FOR SUPPLIES AND CONSUMABLES

Purpose

The element establishes and documents the system of inspecting and accepting supplies and consumables.

Critical Supplies and Consumables, Inspection and Acceptance Requirements and Tracking

The critical supplies and consumables, the inspection and acceptance requirements and tracking are presented in Table B8.2.1

Table B8.2.1 Critical Supplies and Consumables, Inspection, Acceptance Requirements, and Tracking

Supplies/ Consumables	Inspection Requirements	Acceptance Requirement	Frequency	Responsible Person	Tracking
Sample bottles	Each lot to have certificate of CLP compliance	precleaned certified to meet EPA CLP criteria	Each lot.	Laboratory Coordinator	Logged into notebook on receipt.
Hydrogen peroxide, potassium chloride, nitric acid, potassium permanganate	1) Order the correct number. 2) Review label or bottles for source, purely sealed bottles.	Analysis on label indicates level the purity required - trace metals.	On receptor each lot to reagent.	Laboratory Coordinator	Logged into notebook on receipt.
Deionized water	On prevention on the lot for field and laboratory use.	Meets ASTM type II criteria.	Preparation of each lot of work.	Laboratory Coordinator.	Logged into notebook on receipt.
Orsat Reagents	The correct item ordered sealed bottles.		On receipt of lot.	Field Personnel	Logged into notebook on receipt.
Sample Nozzles	Checked for sharp edge, chips or cracks. Correct length and diameter.	Sharp edge, edge not chipped nor cracked. Correct length, correct diameter.	Receipt of each lot and before use in field.	Field personnel	In calibration files.
Type S pitot tubes	Checked for conformation & requirements of EPA Method 2 pitot tube should not be bent & the sensing head has sharp edges on impact and wake openings. No nicks.	Meets requirement of EPA Method 2	On receipt & prior to & on completion of test run.	Field Personnel	In calibration files.

DATA ACQUISITION REQUIREMENTS (NON-DIRECT MEASUREMENTS)

Purpose/Background

This element of the QAPP identifies data to be acquired from others and the intended sources of such data.

Acquisition of Non-Direct Measurement Data

Extensive data will be collected from plant operators, such as fuel feed rates, boiler and pollution control system operating conditions, and continuous emission monitoring (CEMS) data. These data will be retrieved from the plant data acquisition and operating system in electronic and/or hard copy. These data will be utilized to document the operations during each run.

DATA MANAGEMENT

Purpose/Background

This QAPP element describes the data manipulations to be conducted to change the form of data expression, location, quantity, or dimensionality. This element addresses data recording, validation, transformation, transmittal, reduction, analysis, management, storage, and retrieval.

Data Recording

This section of the QAPP lists the data entry forms to be used to record calibration and sampling data. These forms are represented in Appendix B of each SSTP.

Calibrations Figures:

Type "S" Pitot Tube Conformation and Configuration
Dry Gas Meter Calibration Worksheet
Dry Gas Meter & Orifice Calibration Sheet
Meter Box thermocouple Calibration Form
Nozzle Calibration
Probe Thermocouple Calibration Form

Field Data Sheets:

Field Program Log
Traverse Point Location Data Sheet
Stack Geometry & Gas Velocity Data Sheet
Field Moisture Data Sheet
Isokinetic Flue Gas Sampling Data Sheet
Sampling Train Setup & Recovery Sheet
Orsat Analysis
Chain of Custody Sheet Sampling
Chain of Custody Sheet Shipping
Steam Generator Operations Data Sheet
Electrostatic Precipitator Operations Data Sheet

All field data will be recorded in ink on the respective method data sheets and in the field laboratory notebook. All corrections will be crossed out, initialed and dated. At the conclusion of each test run, the field team leader will review all data sheets for completeness, accuracy of data recording, other errors. The person originating the data sheet will correct noted omissions, errors etc.. During the conduct of a run, the field team leader will frequently observe the data recording by the staff to ensure that the data is accurately recorded.

Data Validation

Data validation is the process of accepting or rejecting data on the basis of established criteria. The QA officer and Laboratory Coordinator using criteria outlined in this QAPP will validate analytical and sampling data. They will use validation methods and criteria appropriate to the type of data, even that judged to be an "outlying" or spurious value. The persons validating the data will have sufficient knowledge (i.e. at least one year experience in data validation) of the sampling and analytical methods to identify questionable values and deviations from criteria specified in the methods and the QAPP.

Field Data

The Field Team Leader and/or the Laboratory coordinator, and/or the QA Officer based on their review of the adherence to an approved sampling protocol and written sample collection procedure will validate Field sampling data.

The following criteria will be used to evaluate the field sampling data:

- Calibrations of field equipment as specified in the test method;
- Use of approved test procedures;
- Proper operation of the process being tested;
- Use of properly operating and calibrated equipment;
- Leak checks conducted before and after tests;
- Use of reagents conforming to QC specified criteria;
- Proper chain-of-custody maintained.
- The F_o factors of Method 3B will be used to validate the CO_2/O_2 data. The F_o factor for bituminous coal is expected to fall between 1.083 - 1.230.
- The volumetric flow rate for the inlet and outlet locations will be compared. Agreement should be within 10%.

18.

Laboratory Data

Laboratory data will be reviewed by the analyst generating the data. Then the data will be reviewed by the supervisor. The laboratory QC personnel will review the data per the laboratory procedure before the project report is prepared by the Laboratory Project Manager.

The results from the field and laboratory method blanks, replicate samples, and internal QC samples will be used to further validate analytical results. Analytical results on the field blanks and replicate samples also are valuable for validation of sample collection. The QA/QC personnel will review all laboratory and sampling raw data to verify calculated results presented, consistency, duplicate sample analysis, spike recoveries, tests for outliers, and transmittal errors.

Identification and Treatment of Outliers

Any point that deviates from others in its set of measurements will be investigated; however, the suspected outlier will be recorded and retained in the data while it is investigated. One or both of the following tests will be used to identify outliers:

- Dixon's test for extreme observations is an easily computed procedure for determining whether a single very large or very small value is consistent with the remaining data.
- The one-tailed t-test for difference may also be used in this case.

19.
If more than one outlier is suspected in the same data set, other statistical sources will be consulted, and the most appropriate test of hypothesis will be used and documented.

Because an outlier may result from unique circumstances at the time of sample analysis or data collection, those persons involved in the analysis and data reduction will be consulted. This evaluation may provide an experimental basis for the outlier to determine its effect on the conclusions. In many cases, two data sets will be reported, one including and excluding the outlier.

Data Transformation

Data transformation and Equations are described in Section 5.0 of the respective SSTP.

Data Transmittal

Field Data

At the completion of each test run, the sampling location leader collects all the data sheets for the location which he hand delivers to the field team leader. The field team leader transfers these sheets to designated 3 ring binders for each run. At the completion of the sample train recoveries and orsat analyses, the laboratory recovery chemist hand delivers these data sheets to the field team leader who places them in the respective binders. At the completion of the field phase, the field team leader transports the binders to the office. These binders are then placed in a file cabinet in his office.

Analytical Data

The analytical data packages are transmitted to the TRC Laboratory Coordinator by overnight express courier. Package tracking numbers and air bills become part of the chain of custody. The data packages are reviewed by the Laboratory Coordinator and then transferred to the project file.

Data Reduction

The field and analytical datasheets are removed from the project files by the data reduction person for entry into the computer spreadsheets. Upon completion of the data entry phase - all data are returned to the project managers files.

Data Reduction

All data will be reduced by computer utilizing excel spreadsheets. Initially, all field data collected will be reviewed and preliminary results calculated in the field by the Field Team Leader and at least one other field crewmember. The final data reduction will be performed in the office.

The data input from the field data and analytical data sheets to the computer spreadsheets will be checked to ensure that the data has been transferred accurately. All errors and omissions will be corrected. The Project Manager, QA Officer or the Laboratory Coordinator will conduct this process.

The QA Officer will run an independent check of the calculation spreadsheets. This will entail: 1) hand calculating one run data set and comparing the results to those on the spreadsheet; 2) reviewing the electronic copy of the spreadsheet prior to use in the field to ensure equations are correct and that spreadsheet links are operating correctly.

Data Analysis

The analytical data will be subjected to the analyses for precision, accuracy and completeness as described below.

Precision

When sufficient data are available, precision is determined through the analysis of replicate or replicate spiked samples and is expressed as either relative standard deviation (RSD) or relative percent difference (RPD). The following equations are used when eight or more measurements are made:

$$RSD = 100 \times \frac{S}{X}$$

where:

X	=	arithmetic mean
S	=	standard deviation

Standard deviation will be determined as follows:

$$s^2 = \frac{1}{(n-1)}\left[\sum_{i=1}^{n} (x_i - \bar{x})\right]^{1/2}$$

where:

x	=	average of the measurements
X_i	=	individual measurement

n = number of measurements

Precision of duplicate analyses is expressed as relative percent difference (RPD) and calculated as follows:

$$RPD = \left| \frac{Value1 - Value2}{Arithmetic\ Mean\ of\ Values\ 1\ and\ 2} \right| x\,100$$

Accuracy

Reference Method Tests and Analytical Measurements

Accuracy will be estimated from the analysis of matrix spiked samples and/or laboratory control samples, and will be expressed as percent recovery or as relative error. The formulas to calculate these values are:

$$Percent Recovery = 100\ x\ \frac{Measured Value}{True Value}$$

$$Relative\ Error = 100\ x\ \frac{Measured\ Value - True\ Value}{True\ Value}$$

Completeness

Completeness will be reported as the percentage of all measurements made whose results are judged to be valid. The procedures to be used for validating data and determination of outliers are contained in Section 6.0 of this Plan.

The following formula will be used to estimate completeness:

$$C = 100\ x\ \frac{V}{T}$$

where:

C = percent completeness
V = number of measurements judged valid
T = total number of measurements

Data Tracking

The project manager tracks the flow of data from collection to final data reduction and reporting.

Data Storage and Retrieval

During the conduct of the field phase of the program, all completed data sheets, plant DAS printouts, field notes are maintained in three ring binders. These binders and laboratory notebooks are maintained in the onsite field laboratory filing cabinet, when not being utilized. This laboratory is locked when no one is present inside. At the completion of the testing, the files are transferred to the Field Team Leader for transport to the TRC offices. The

working files are stored in the Program Managers Office file area. All TRC personnel will have access to these files; the program manager will be responsible for keeping track of the files removed from the file area.

At the completion of the program, the files will be transferred to storage boxes and placed in the TRC Records Retention Center. The archived material is retrieved from the Center by submitting a file request form to the Records Retention person. The file is signed for on receipt and is signed back in upon completion of use. All documentation, including the QAPP, SSTP, Final Test Report, all raw field data, analytical laboratory data packages, field and laboratory notebooks, logbooks will be maintained in the stored program file by TRC for a minimum of five years after completion of the test program. Analytical laboratories will maintain the data file according to their standard operating procedures.

ASSESSMENT/OVERSIGHT

ASSESSMENTS AND RESPONSE ACTIONS

Purpose/Background

This QAPP element identifies the assessment and reporting activities for this project.

Assessment Activities and project planning

TRCs Quality Assurance Program includes both performance and system audits as independent checks on the quality of data obtained from sampling, analysis, and data gathering activities. Every effort is made to have the audit assess the measurement process in normal operation. Either type of audit may show the need for corrective action.

ADA-ES or TRC do not plan to undertake management system reviews during this project.

Readiness reviews will be conducted before going into the field. Such reviews will be conducted by project management staff and the QA Manager. The Field Team Leader will conduct a readiness review at Salem Harbor Unit 1 before testing is initiated.

Surveillance will be conducted for the duration of the project. Aspects of this function include routine oversight of the project by the Program Manager, monitoring of field activities by the Field Team Leader, and review of QC procedures by the QA Officer.

A technical system audit may be conducted at the test site. Such an audit will be performed by an independent third party who will report directly to EPA. The technical system audit will involve a systematic on-site qualitative examination of facilities, equipment, personnel, training, procedures, and record keeping to assess conformance with the QAPP. Corrective actions, if deemed necessary, will be implemented during the audit.

TRC anticipates that performance evaluations of the field and analytical instrumentation by use of audit devices/samples will be conducted for this program. The audit devices/samples are to be provided by USEPA.

Data quality audits will be conducted using procedures specified in the QAPP (see elements B9 and B10) and the SSTP.

The SSTP and project report will be subjected to review by the TRC QA Officer, and Laboratory Coordinator, ADA-ES Program and Plant Program Coordinator and USDOE.

Data quality assessments will be conducted using the statistical tools described in Section 6 of the SSTP.

Documentation of Assessments

All assessments described in this QAPP element will be described in the project report that documents the results of each field test program.

REPORTS TO MANAGEMENT

Internal Reports

The TRC Laboratory Services Coordinator and Field Team Leader prepare written reports on QC activities for the Quality Assurance Officer as needed. These reports detail the results of quality control procedures, problems encountered, and any corrective action that may have been required.

All Corrective Action Forms are submitted to the QA Officer for initial approval of the corrective action planned and a copy is provided to Management.

Report to Client

The data transmitted will contain a summary of QA/QC activities. This summary will include:

- Instrument performance/system audits
- Adherence to protocol
- Sample custody
- Document control
- Data entry including error handling, correction, and additions
- Data traceability and completeness
- Data calculation and evaluation
- Quality problems found
- Corrective actions taken
- Data accuracy, precision, and completeness

The final report will include a section summarizing QA/QC activities during the program. The Program Manager, Laboratory Analysis Coordinator, and the QA Officer will participate in preparing this section.

DATA VALIDATION AND USABILITY

DATA REVIEW, VALIDATION, AND VERIFICATION REQUIREMENTS

Purpose/Background

This QAPP element documents criteria used to assess that data quality specifications are achieved. Data will be collected and accepted only when condition requirements for instructions and measurements stipulated in the applicable EPA methods are met.

Sampling Design

The design of the sampling program was delineated by ADA in the SSTP and in the RFP letter submitted TRC. The design stipulates that:

20. • Sampling is occurring simultaneously at the inlet and outlet of final pollution control system (PCS).

21.

TRC is relying on the primary measurement techniques described in the EPA Methods 1, 2, 3B, 4, and Pre-003 to design the stack-testing program. If site conditions are encountered that preclude adherence to primary techniques, secondary or alternate techniques described in the EPA Methods will be adopted, if approved by the DOE & ADA-ES. Use of these standard methods is a primary factor in the determination of data acceptability.

Any deviations from the SSTP and how it affects the results will be addressed in the final report.

Sample Collection Procedures

Flue gas measurements will be conducted in accordance with the primary techniques documented in EPA Methods 1, 2, 3B, 4, and Pre-003. Sampling tolerances are described in the EPA Methods for selection of traverse locations, leaks, Pitot tube plugging, and other QC requirements and are described in element B2. Deviations from the prescribed methods will be documented and how the deviations affect the results will be addressed in the final report.

Sample Handling

The handling of the sample from extraction from the inlet duct, the exhaust stack, and process points to final data reporting will be evaluated as to holding time, preservation, type of container used, chain of custody and storage condition to ensure that the sample was still representative of the milieu from which it was extracted.

Analytical Procedures

The data reports will be reviewed to ensure that the analytical procedures specified in Section B4, i.e., EPA Methods 3B, 4, and Pre-003 for mercury were implemented. Deviations from the procedures are to be documented and any affects on the results are to be discussed.

Quality Control

This section describes the statistical analysis of data. These statistical calculations will be used to assess the data for its precision, accuracy and completeness. Data that fall outside the established control limits will be flagged using an appropriate qualifier.

Blank data, both reagent and train blanks, will be used to assess the cleanliness of field and laboratory operations. Ideally, blanks should not contain any of the target analytes. However, field and laboratory environments, sample containers and reagents used in sample processing may contribute contamination. Target analytes that have been detected in field and/or laboratory blanks above the levels prescribed for each analyte class will be flagged during the data review process. Field blank data will be applied only to samples associated with each particular blank. Any corrective action and the effect thereof by the laboratory are to be documented in the data report.

Calibration

Calibration procedures are documented in the EPA Methods, as described in element number B7 of this QAPP. Factors important to data quality include:

- The time lag between calibration and measurement
- The number of calibration points
- The measurement range bracketed by the calibration points
- The stability of the measurement system during calibration and subsequent time

22.
Any pre and/or post-test calibration problems will be documented and how it affects the results will be discussed in the report.

Data Reduction and Processing

Methods to be used to reduce and process measurement data are described in element A10.3 of this QAPP. Any problems with the data reduction will be documented and the affects on the results will be addressed in the report.

VALIDATION AND VERIFICATION METHODS

Purpose/Background

The processes used for data validation and verification are described in this QAPP element.

Process for Validating and Verifying Data

Acceptability criteria for QC samples has been established by the DQOs and the estimated precision and accuracy of the analytical methods. QC samples are used to measure accuracy, precision, contamination, and matrix effects. Conclusions about the quality of the data will be based on whether limits of acceptability criteria were exceeded and the degree to which they were exceeded. QC samples may include blanks, equipment rinsates, field duplicates, field control samples, laboratory control samples, matrix duplicates and spikes, method blanks, split samples, surrogates, or trip blanks.

The limits of acceptability criteria for blanks and rinsates are values that are either no greater than:

23. The quantification or reporting limit

If the acceptability criteria are exceeded by the result obtained for the blank or rinsate, then the sample may be contaminated. Corrective action is required, and the data must be flagged.

Reports generated from the data management system and data package review reports will be used to compare the precision and accuracy achieved with the goals stated in this QAPP. Actual field sample data will also be reviewed for reasonableness based on knowledge of the process and the feed material. QC reports will include:

- QC procedures taken.
- Interpretation of the calculated QC results such as precision and accuracy.
- Corrective actions with an explanation, when necessary.
- Comparison of precision, accuracy and blank results with acceptability limits.
- Completeness of sampling, data and field records. Completeness of field records includes a check of field actions against the QAPP, along with documentation of all deviations from this plan.
- Representativeness of sample data.
- Comparability of project sample data with appropriate sample data gathered concurrently or historically.

24.
The laboratory must provide a complete data package to the TRC Laboratory Coordinator for

each laboratory batch. Laboratory data packages must include:

- Documentation of the QC procedures taken, including raw data for QC analyses.
- Results of all laboratory blanks, spikes and duplicates.
- Calculation of accuracy and precision indicators (percent recovery and RPD).
- Interpretation of these calculated results.
- Corrective action with an explanation, when necessary.
- Deviations from the analytical procedure or stated detection limits.

25.

The laboratory will be contacted when information is noted to be missing from the data package or additional information is required to resolve a data usability question. The request to the laboratory and the laboratory response will be documented and added to the data package and data review report. A copy of the data package will be provided in the report. Completeness will be calculated by comparing the number of data points judged valid with the total number of data points possible based on the samples actually collected.

A summary of QC results and discussion of their impact on data usability will be provided in the final report.

Assessment of data will involve examining the results presented in the data package against the requirements for usability stated in this QAPP. Full validation of data involves examination of all records associated with sample collection, custody and analysis including verification of a percentage of calculations and review of analytical data to confirm the analyst's interpretation. The TRC Laboratory Coordinator will perform a partial validation on all data packages.

RECONCILIATION WITH DATA QUALITY OBJECTIVES

Purpose/Background

This element of the QAPP documents evaluations of data to be used to determine if the data are of the right type, quantity, and quality to support their intended use.

Reconciliation of Results with DQO's and User Requirements

Comparison of QC results with DQOs will be ongoing during the project. Prompt review of trends in blank results and analytical precision and accuracy will allow for early detection and correction of problems before the usability of large quantities of data are impacted. Problem areas will be communicated to field and/or laboratory personnel as appropriate. When QC results outside of acceptance limits are reported, the associated data package may be subjected to further review or the laboratory may be requested to provide additional information. Flagging codes will be applied to the data to indicate limitations on the usability. In extreme cases, individual data points may be rejected.

Due to the time constraints on this work, there will be little or no opportunity for re-sampling. Strict adherence to QC requirements will be extremely important during every step of the sampling and analysis programs. The goal of this program is to gather sufficient valid data to permit the use of the data in the mercury emissions standard setting process. Therefore, every effort must be made to minimize the amount of rejected data. Flagging codes will be used where appropriate to reflect uncertainty in reported results.

LIST OF ACRONYMS

BTU	British Thermal Units
CCC	Continuing Calibration Check
CFR	Code of Federal Regulations
COC	Chain-of-Custody
CVAAS	Cold Vapor Atomic Absorption Spectroscopy
EMC	Emissions Measurement Center
EPA	Environmental Protection Agency
I.D.	Inner Diameter
LCS	Laboratory Control Sample
LOQ	Limit of Quantitation
MS	Matrix Spike
MSD	Matrix Spike Duplicate
P&A	Precision and Accuracy
QA	Quality Assurance
QAPP	Quality Assurance Project Plan
QC	Quality Control
RE	Removal Efficiency
SSTP	Site Specific Test Plan
TRC	TRC Environmental Corporation
USEPA	United States Environmental Protection Agency
NIST	National Institute of Standards & Technology
SRM	Standard Reference Material
SNCR	Selective Non Catalytic Reduction
ESP	Electrostatic Precipitator
DAS	Data Acquisition System
ADA-ES	ADA-Environmental Solutions, LLC
PCS	Pollution Control System
DOE	United States Department of Energy

LIST OF UNITS AND MEASUREMENTS

acfm	Actual Cubic Foot Per Minute
afpm	Actual Foot Per Minute
ΔP	Delta P
dscf	Dry Standard Cubic Foot
dscf/hr	Dry Standard Cubic Foot per Hour
dscfm	Dry Standard Cubic Foot Per Minute
dscm	Dry Standard Cubic Meters
ºF	Degree Fahrenheit
ft	Foot
g	Grams
gal	Gallon
gpm	Gallons Per Minute
gr	Grain
g/s	Grams Per Second
g/hr	Grams Per Hour
in. Hg	Inches of Mercury
in.wc	Inches of Water Column
kg/hr	Kilograms Per Hour
L	Liter
lbs/hr	Pounds Per Hour
Lpm	Liters Per Minute
mg	Milligram
mg/dscf	Milligrams Per Dry Standard Cubic Foot
mg/dscm	Milligrams Per Dry Standard Cubic Meter
mg/m^3	Milligrams per Cubic Meter
mL	Milliliters
MW	Molecular Weight
N	Normal
ng	Nanogram
π	Pi = 3.141592654
PB	Barometric Pressure
ppmdv	Parts Per Million on a Dry Volume Basis
sq. in.	Square Inch
µL	Microliter
µg	Microgram
µg/dscf	Micrograms Per Dry Standard Cubic Foot
$µg/m^3$	Micrograms per Cubic Meter
µg/L	Microgram per Liter

LIST OF CHEMICAL SYMBOLS AND FORMULAS

CO_2	Carbon Dioxide
DI H_2O	Deionized Water
Hg	Mercury
HNO_3	Nitric Acid
H_2O_2	Hydrogen Peroxide
H_2SO_4	Sulfuric Acid
$KMnO_4$	Potassium Permanganate
O_2	Oxygen

APPENDIX B

RESULTS OF SNCR ON/OFF TESTING

ADA Environmental Solutions, LLC

8100 SouthPark Way, B-2
Littleton, Colorado 80120
Fax: 303.734.0330
***303.734.1727** or 1.888.822.8617*

memorandum

To: Jean Bustard, Doug Bondar, Mike Kane, Allen Sload, Ramsay Chang, Sharon Sjostrom, Rui Afonso, Steve Johnson

From: Travis Starns, Sheila Haythornthwaite

CC: Mike Durham, Cam Martin, Brian Donnelly

Date: September 20, 2002

RE: Preliminary Results from SNCR On/Off Testing – Salem Harbor Hg Field Tests

Note: These data are preliminary and confidential to Salem Harbor Hg project team members.

Primary Goals for Week of September 16: SNCR On/Off Tests:

1. Measure vapor phase mercury with Apogee's Hg S-CEMs and with the SNCR in both the Off/On positions.
2. Measure ammonia in the flue gas during start up of the SNCR system
3. Determine coal and ash sampling procedures
4. Determine data collection procedures

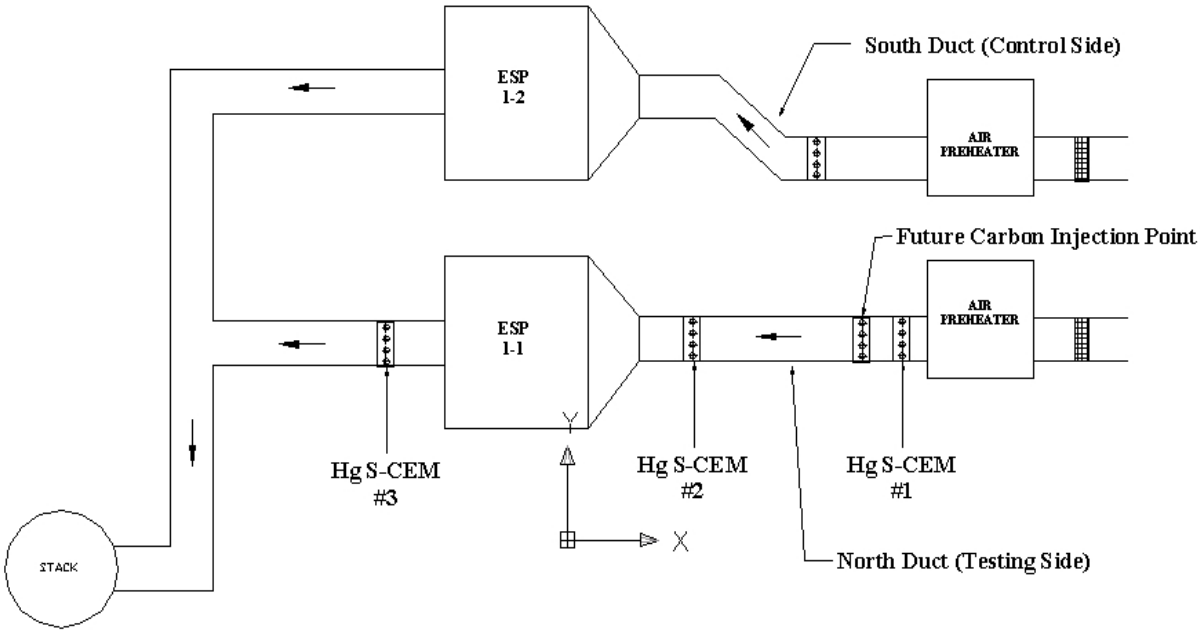
Completed Tasks:

1. Unit 1 successfully operated without the SNCR in operation immediately after start up from outage.
2. Apogee personnel started up and calibrated the Hg S-CEMs at both the inlet and outlet (#1 and #3 Hg sampling locations) of Unit 1 ESP.
3. Collected mercury measurements at the second location (#2) inlet to the ESP. This particular location will give us in-flight Hg removal data between locations #1 and #2.
4. SNCR system was placed back into service on Wednesday, Sept. 18, and NO_x emissions decreased from about 0.41 lb/MMBtu to below their current regulatory emissions limit of 0.33 lbs/MMBtu.
5. The Hg project team completed ammonia measurements during the afternoon following SNCR start up on Sept. 18.
6. ADA-ES personnel met with plant personnel and set up procedures for collecting fly ash and coal samples from Unit 1. Shawn O'Brien is picking up containers daily from the ADA-ES trailer, collecting the samples per the schedule, and dropping off labeled containers in the mid-afternoon. He will collect samples around 2:30 PM each day.
7. Set up procedures to obtain operation and performance data from the plant archive system (PI)

Results and Comments:

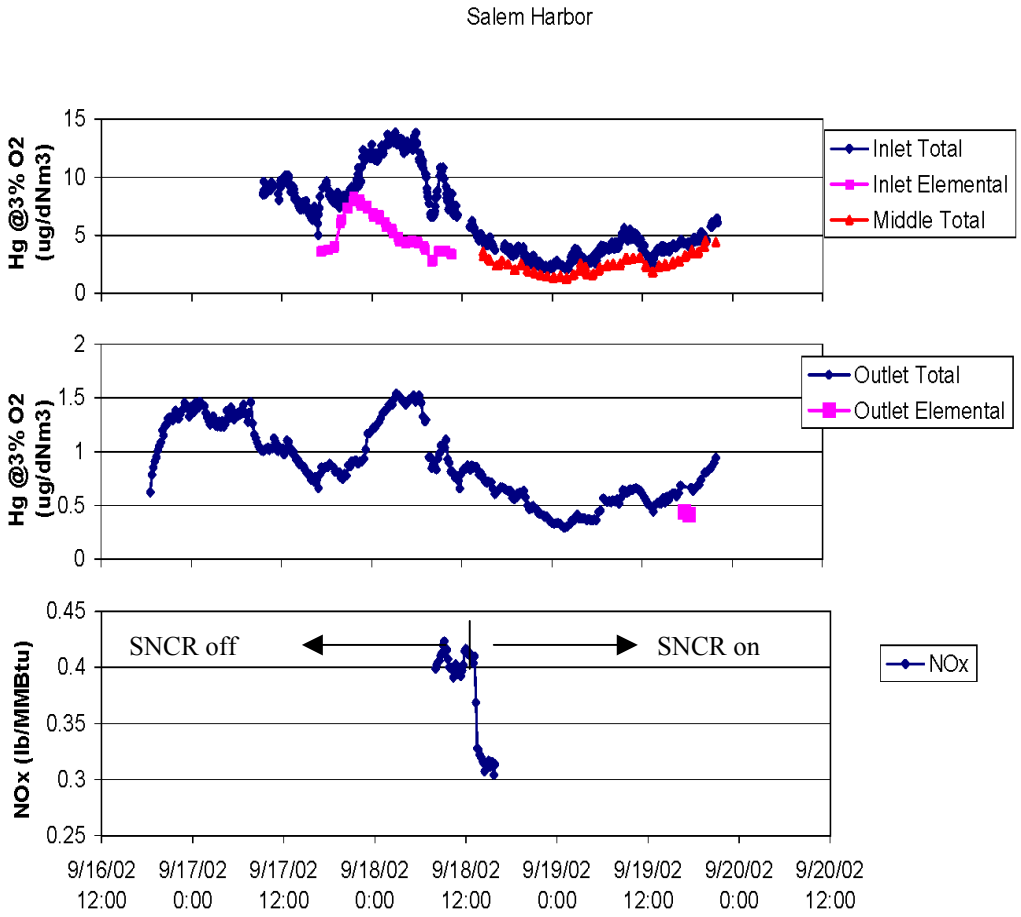
Apogee Scientific has strategically positioned (3) Hg S-CEMs on half of Unit 1 flue gas, on the north duct. The Hg project team is essentially testing half the unit (~ 44 MW) with the south duct being the control side and the north duct being the test side. The first Hg S-CEM extraction location (#1) is immediately downstream (~ 10') of the air preheater. The second Hg S-CEM extraction location (#2) is located approximately 65' downstream of location #1 and upstream of the ESP approximately 30'. Between these two respective locations (#1 & #2) this will give us approximate in-flight vapor phase mercury removal data. The final location (#3) for mercury measurements is located on the I.D. fan inlet duct downstream of the ESP. These three Hg S-CEM locations can be seen in Figure 1 below.

Figure 1. Hg S-CEM locations at Salem Harbor Unit 1 (North Duct)



On September 16, 2002 PG&E NEG Salem Harbor Station (SHS) Unit 1 came up from outage with the SNCR system out of service. Mercury measurements were made at locations #1 and #3 giving us vapor phase mercury removal data from air preheater exit to the ESP exit. Preliminary analysis of the Hg S-CEM data collected during the SNCR tests indicate an approximate vapor phase Hg removal of 90% between locations #1 and #3. These trends can be seen in Figure 2 below.

Figure 2. Salem Harbor Hg Trends during SNCR Off/On Tests.
This data is preliminary.



It is worth noting that the total inlet Hg concentration levels as measured by the Hg S-CEMs are considerably higher than expected when comparing to the other historical data collected for Unit 1 (this week's Hg ranges from 6 to 12 ug/Nm^3, compared with prior measurements showing about 1 to 4 ug/Nm^3).

Preliminary analysis of these data, indicate the presence of ammonia in the flue gas from the SNCR system, doesn't appear to affect the overall native mercury capture for Unit 1.

Figure 1 also shows some data from location #2 ("Middle Total"), indicating ~ 20-30% in-flight removal of mercury by the ash. The corresponding trends of the three locations' mercury data, using three different sample systems and two different analyzers, is an encouraging indication for the performance of the Hg S-CEMs.

During these tests fly ash and coal samples are collected daily by plant personnel. These samples are then transferred to ADA-ES personnel where they are logged in the database and packaged for shipping. Hg measurements on the coal samples collected during the SNCR Off/On tests will be performed so we can confirm the high mercury concentrations being measured by the Hg S-CEMs. These samples will be analyzed expeditiously to confirm the higher-than-usual mercury levels. Table 1 below represents the fly ash and coal sampling schedule during the SNCR OFF/ON tests.

Table 1. Coal and Fly Ash Sampling Schedule for Salem Harbor – SNCR Off/On Tests

Date	Coal					Fly Ash							
	Feeders					ESP (Testing Chamber)				ESP (Control Chamber)			
	1-1	1-2	1-3	1-4	Composite	A- Row	B- Row	C-Row	D-Row	A-Row	B-Row	C-Row	D-Row
16-Sep		A				A	A	A	A				
17-Sep		A				A	A	A	A				
18-Sep		A				A	A	A	A				
19-Sep		A				A	A	A	A				

A – 1 Liter Sample

As well as mercury measurements, ammonia measurements were taken during the start up of the SNCR system on Wednesday, September 18. The SNCR system was placed into service at approximately 13:00 hours, and as seen in Figure 1 above, NO_x emissions immediately dropped to ~ 0.33 lbs/MMBtu. The ammonia samples collected were sent back to the Apogee Scientific Laboratory for analysis.

Next Week: Baseline Testing

The baseline testing series begins on Monday, September 23. TRC Environmental Corporation will be conducting Hg measurements at locations #1 and #3 using the Ontario Hydro testing method. In addition to the Ontario Hydro tests, they will perform a metals test (Method 29) along with HCl and ammonia measurements. During the baseline testing series, there will be no activated carbon injection (ACI). The Hg project team will not perform ACI until the following week during the parametric testing series. For a complete schedule of the baseline and parametric testing series please see Table 2 below.

Table 2. Proposed Full Scale Test Sequence at Salem Harbor

Test Description	Dates	Parameters/Comments	Boiler Load
Operational pre-test	9/3-9/6	Modify temperature and LOI/carbon levels to quantify the limits on these process variables	100%, 70%
SNCR off: From Unit startup for two days, or until steady, high-load conditions are obtained	Startup ~9/16 until ~9/19	Keep SNCR off to keep unit clean of NH3 until baseline measurements are made Day 1 – Startup Day 2 – SCEM with no SNCR Day 3 – SCEM with no SNCR Day 4 – SCEM with SNCR	Startup, Steady load during actual tests (two days)
Baseline Tests (No sorbent injection; normal unit operating conditions) followed by off-normal conditions on Days 4&5	9/23-9/27	Day 1- Ontario Hydro & M29 tests Day 2- Ontario Hydro &M29 tests Day 3- Ontario Hydro & M29 tests Day 4 & 5- Reduce LOI/carbon by detuning burners (increase air, decrease load slightly as needed) *	Full Load 24 hours per day *** - Dates and times TBD**
Parametric Week 1 (LOI/carbon and Temperature effect on Hg capture, with and without sorbent injection)	9/30-10/4	Day 1- Increase Temperature with reduced LOI/carbon * Day 2- Depending on previous results, change LOI/carbon or Temperature again Day 3- Add sorbent injection at medium rate (8-15 lb/MMacf) to high temperature, low LOI/carbon condition. Day 4- Sorbent injection at high injection rate (10-20 lb/MMacf) with high temperature, low LOI/carbon condition. Day 5 - Contingency	Full Load 6AM-6PM *** Times to TBD**
Parametric Week 2 (Sorbent injection in combination with process variables)	10/7-10/11	Day 1- Low injection rate (1-5 lb/MMacf) with lowest-removal condition tested (LOI/carbon, Temperature variables) Day 2- Low injection rate with normal operation. Day 3- Medium injection rate (8-15 lb/MMacf) with normal op. Day 4- High injection rate (10-20 lb/MMacf) with normal op.	Full Load 6AM-6PM
Long-term tests (Darco FGD injection; rate TBD)	11/4-11/13	Operate at consistent injection rate 24 hours a day while load following. Conduct Ontario-Hydro and Method 29 tests during 11/7-11/8 if possible; 11/11 -11/12 are the contingency test days.	Full Load only during Ontario Hydro

If anyone has any questions or concerns about results or the test plan itself don't hesitate to contact Travis Starns.

Office: 303.734.1727
Cell: 303.881.6154

traviss@adaes.com

APPENDIX C

BASELINE TESTS

ADA Environmental Solutions, LLC

8100 SouthPark Way, B-2
Littleton, Colorado 80120
Fax: 303.734.0330
***303.734.1727** or 1.888.822.8617*

memorandum

To: Jean Bustard, Doug Bondar, Mike Kane, Allen Sload, Ramsay Chang, Sharon Sjostrom, Rui Afonso, Steve Johnson, Hg Project Team

From: Travis Starns, Sheila Haythornthwaite

CC: Mike Durham, Cam Martin, Brian Donnelly

Date: October 3, 2002

RE: Preliminary Results from Baseline Testing Series– Salem Harbor Hg Field Tests

Note: These data are preliminary and confidential to Salem Harbor Hg project team members.

Primary Goals for Week of September 23: Baseline Testing Series:

1. Measure Hg concentrations (μg/Nm^3) at the inlet and outlet measurement locations (#1 and #3 respectively) via the Hg S-CEMs and Ontario Hydro Testing Method.
2. Measure metals emissions (Method 29) at both inlet and outlet measurement locations.
3. Measure of HCl and Ammonia concentrations in the flue gas at the inlet location.
4. Determine what effect, if any, reducing normal operating LOI levels in the flue gas has on Hg concentrations at the inlet and outlet locations and overall mercury capture across the system.
5. Increase ESP inlet temperatures by 50°F and measure Hg concentrations at both the inlet and outlet locations with the Hg S-CEMs.
6. Operate Unit 1 at both increased ESP inlet temperatures and lower LOI levels and measure Hg at both the inlet and outlet locations.
7. Collect ash and coal samples from Unit 1.

Completed Tasks:

1. TRC Environmental Corporation successfully completed triplicate runs of the Ontario Hydro testing method, Method 29, HCl, and Ammonia measurements.
2. Apogee Scientific successfully collected Hg measurements at both the inlet and outlet locations.
3. Determined the speciated mercury measurements (Hg^0 and Hg^{2+}) at the inlet measurement location.
4. Reduced LOI levels, by dropping load at normal operating conditions from 30-35% at ~85 MW, to 15-22% at 65 MW.
5. Increased air preheater outlet temperatures using steam coils, thus raising the ESP inlet and outlet temperatures.

6. Documented and logged all coal and ash samples collected during the baseline testing series.

Results and Comments:

On Monday, September 23 TRC Environmental Corporation started the first of three Ontario Hydro tests that were to be conducted once a day. In addition to the Ontario Hydros, TRC also conducted triplicate runs of Method 29 (inlet and outlet locations) and measured the HCl and ammonia concentrations at the inlet location. Three successful runs of each test were completed by Wednesday afternoon with Unit 1 at full load conditions (86 MW). These tests were conducted in a safe and timely manner under the direction of Mike Martin. Many thanks goes out to PG&E Salem Harbor plant personnel for preparation of the test ports and locations.

In parallel with the testing conducted by TRC Environmental Corporation, the Hg S-CEMs supplied by Apogee Scientific were measuring vapor phase mercury concentrations at both the inlet and outlet locations. Measurements made with the Hg S-CEMs showed an approximate vapor phase mercury removal of > 80%. . Inlet mercury concentrations were nominally 2-4 $\mu g/Nm^3$ and outlet concentrations were 0.3-0.5 $\mu g/Nm^3$.

On Wednesday, September 25 in the late night hours, Unit 1 boiler load was decreased from ~85 MW to ~65 MW. This boiler load decrease and a slight adjustment to the excess air appeared to drop LOI levels from mid 30% range to approximately 20%, based on the on-line LOI analyzer. This change in operating conditions increased the vapor phase mercury concentrations at both the inlet and outlet locations. Further detailed analysis continues as to what specifically caused this particular increase.

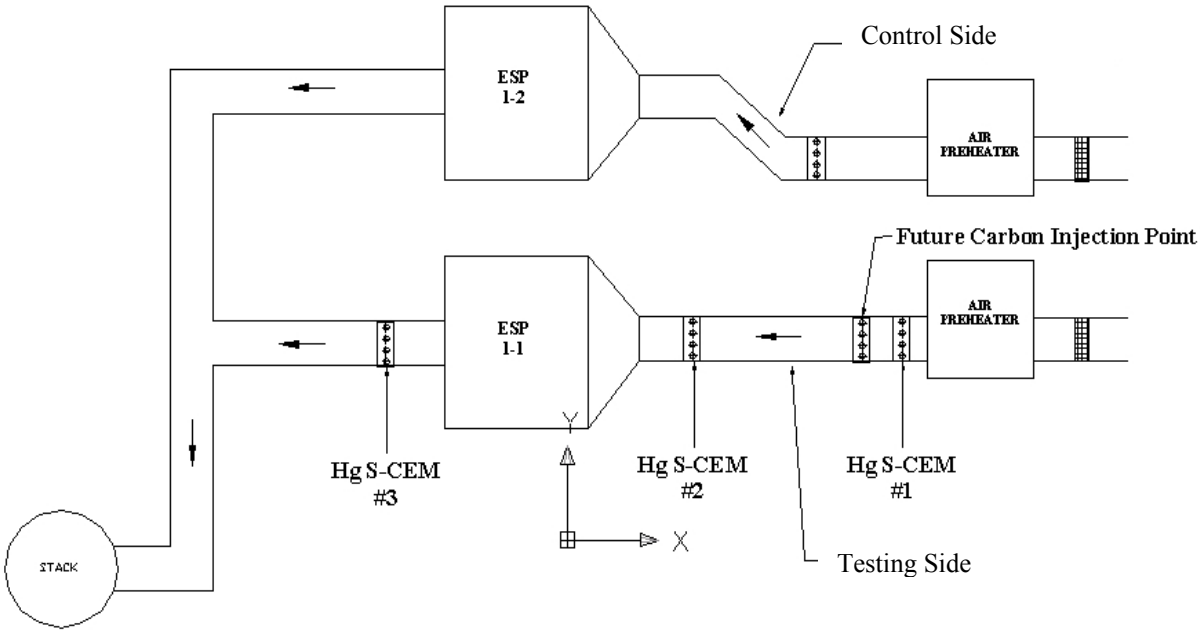
The following night between the hours of 19:30 – 06:00 the effects of combining increased flue gas temperature with a reduced LOI condition were evaluated. At 19:30, the steam coils were placed into service, and ESP inlet temperatures were increased approximately 40-50°F to an operating temperature range of 310-320°F at the ESP inlet. Unit 1 operated at this increased temperature condition for a period of 2 ½ hours. During this time, vapor phase mercury concentrations appeared to increase at both the inlet and outlet of the ESP as measured by the Hg S-CEMs.

After operating at that condition for 2 ½ hours, the decision was made to reduce load from 85 MW to 65 MW and operate at the lower LOI condition with the steam coils still in service. LOI dropped from about 35% to about 20%, per the LOI analyzer. Once again, an increase in vapor phase mercury concentrations was observed at both the inlet and outlet locations. Further testing and additional data analysis needs to be completed to fully understand what mechanism specifically caused the increase, to determine whether it is a short-term or long-term effect, and to accurately quantify the effect. This may be important to Salem Harbor and other sites in setting process conditions appropriate to meet future mercury emission limits.

During these test conditions (lower LOI and increased temperature), Hg concentrations increased from 2-4 $\mu g/Nm^3$ to approximately 8 $\mu g/Nm^3$ at the inlet location. Data from the Hg S-CEMs also indicates an increase at the outlet location. The physical location of these measurement locations can be seen in Figure 1 below (for data reported herein, locations #1

(ESP inlet) and #3 (ESP outlet) were used). Hg measurements from coal analyses will be made to confirm these measurements.

Figure 1. Hg S-CEM locations at Salem Harbor Unit 1



During these tests ESP fly ash and coal samples are collected daily by plant personnel. These samples are then transferred to ADA-ES personnel where they are logged in the database and packaged for shipping. Hg measurements on the coal samples collected during the lower LOI tests will be performed to help understand the variability in mercury concentrations being measured by the Hg S-CEMs. These samples will be analyzed expeditiously to confirm the higher-than-usual mercury levels. Table 1 below represents the fly ash and coal sampling schedule during the baseline testing series.

Table 1. Coal and Fly Ash Sampling Schedule for Salem Harbor – SNCR Off/On Tests

Date	Coal					Fly Ash							
	Feeders					ESP (Testing Chamber)				ESP (Control Chamber)			
	1-1	1-2	1-3	1-4	Composite	A- Row	B- Row	C-Row	D-Row	A-Row	B-Row	C-Row	D-Row
23-Sep	A	A	A	A		A, 2B	A, B	A, B	A, B	A	A		
24-Sep	A	A	A	A		A, B	A, 2B	A, B	A, B				
25-Sep	A	A	A	A		A, 2B	A, B	A, B	A, B	A	A		
26-Sep		A				A	A	A	A				
27-Sep		A				A	A	A	A				

A – 1 Liter Sample
B – 5 Gallon Sample

Week of October 7, 2002: Parametric Testing Series 1.0

The parametric testing series begins on October 7. After preliminary analysis of the data collected during the baseline testing series, the testing schedule has been revised as well as the testing conditions. Further testing of the low load, low LOI, and high temperature condition will help better understand the mechanism for the changes in vapor phase mercury the Hg S-CEMs are seeing. The test schedule and testing conditions are waiting for approval from the appropriate PG&E Salem Harbor plant personnel. Once the Hg project team has approval from the plant, the revised testing schedule will be released.

Once again, the field test data collected has brought forth some rather interesting and exciting results. If anyone has any questions or concerns about results or observations witnessed please contact Travis Starns.

Office: 303.734.1727
Cell: 303.881.6154

traviss@adaes.com

APPENDIX D

PARAMETRIC TESTS

ADA Environmental Solutions, LLC

8100 SouthPark Way, B-2
Littleton, Colorado 80120
Fax: 303.734.0330
***303.734.1727** or 1.888.822.8617*

memorandum

To: Jean Bustard, Doug Bondar, Mike Kane, Allen Sload, Ramsay Chang, Sharon Sjostrom, Rui Afonso, Steve Johnson, Hg Project Team

From: Travis Starns, Sheila Haythornthwaite

CC: Mike Durham, Cam Martin, Brian Donnelly

Date: October 21, 2002

RE: Preliminary Results from Parametric Testing Series

Note: These data are preliminary and confidential to Salem Harbor Hg project team members.

Primary Goals for Parametric Testing Series:

1. Place steam coils into service and determine the effect of increasing flue gas temperature at the ESP inlet has on native mercury removal.
2. Inject activated carbon into the flue gas and determine the sorbent's performance for mercury capture at the increased flue gas temperatures.
3. Determine what effect, if any, reducing normal operating LOI levels in the flue gas has on Hg concentrations at the inlet and outlet locations and overall mercury capture across the system.
4. Inject activated carbon at different injection concentrations (lbs/MMacf) and develop a performance curve for activated carbon at different injection concentrations.
5. Operate Unit 1 at both increased ESP inlet temperatures and lower LOI levels and measure Hg at both the inlet and outlet locations.
6. Collect ash and coal samples from Unit 1.
7. Collect particulate samples from the air heater outlet measurement location and determine the LOI level at location #1.
8. Determine vapor phase Hg concentrations upstream of the air heater (Location #0).
9. Inject activated carbon into the flue gas at normal full load operating conditions and determine the sorbents performance and it's ability to capture vapor phase mercury.

Completed Tasks:

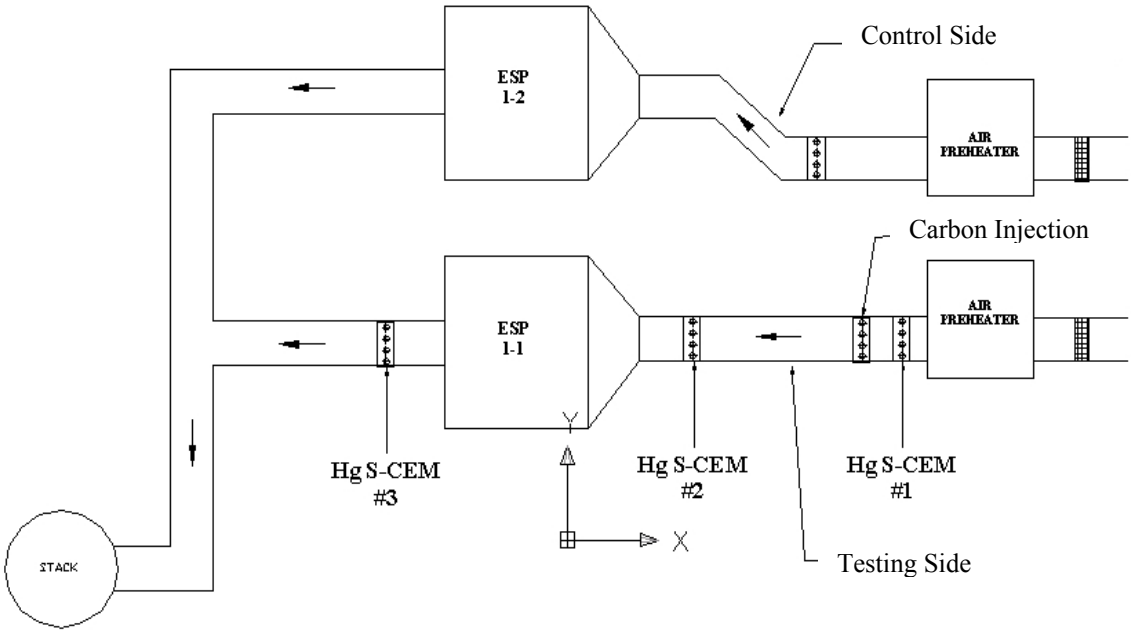
1. Raised air heater outlet temperatures by 50°F and measured vapor phase mercury concentrations at the air heater outlet (Location #1) and ESP outlet (Location #3).
2. Developed performance curves for the activated carbon at elevated temperatures and different injection concentrations.

3. Reduced normal operating LOI levels and measured vapor phase mercury at locations #1 and #3 with and without activated carbon injection.
4. Documented and logged all coal and ash samples collected during the parametric testing series, as well as particulate samples from Location 1 were taken and analyzed for LOI content.
5. Adjusted steam coil temperature output to approximately 50% thus raising ESP inlet temperatures 25°F from normal operating conditions. During this particular operating trend, vapor phase mercury concentrations were measured at locations #1 and #3 with and without activated carbon injection.
6. Measured vapor phase mercury concentrations upstream of the air heater.
7. Performed activated carbon injection at different injection concentrations with Unit 1 at normal and full load operating conditions.

Results and Comments:

Prior to the start of the parametric testing series, the plant began burning a new test coal from Columbia, South America. This particular coal has lower sulfur content and a lower heating value as compared to the coal fired at the Salem Harbor station during the baseline testing series. In general, the new test coal has produced lower vapor phase mercury concentrations at the air heater outlet as measured by the Hg S-CEM. For a schematic of Hg measurement locations and the carbon injection point please see figure 1 below. The data collected from the parametric testing series has shown different trends and results as compared to the data collected from the baseline testing series. Thus, comparison between the two different data sets is difficult and each testing series (Baseline and Parametric) should stand-alone as each coal behaved differently.

Figure 1. Hg S-CEM locations at Salem Harbor Unit 1



On Monday, October 7 plant personnel placed the steam coils into service and raised air heater outlet temps and ESP inlet temps approximately 50°F. With the steam coils in service, the temperature at the air heater outlet increased from 300°F to approximately 350°F as measured by the Hg S-CEM at that location. With Unit 1 at full load (85 MW) and operating at the increased flue gas temperatures, native mercury removal efficiencies decreased to approximately 10-20% as measured from location #1 thru location #3.

The following day, the Hg project team performed activated carbon injection (ACI) at two different injection concentrations 10 & 20 lbs/MMacf respectively. During ACI, Unit 1 was held at full load and air heater outlet temperatures were approximately 350°F. At these operating conditions, vapor phase mercury removal efficiencies from location #1 to location #3 were limited to < 50% with ACI.

As a result of the low vapor phase mercury capture, the decision was made to reduce the air heater outlet temperatures from 350°F to approximately 325°F. ACI was performed at 325°F and an injection concentration of10 lbs/MMacf. Vapor phase mercury removal efficiencies increased as compared to the same injection concentration at the higher flue gas temperatur. Thus, flue gas temperature appears to have a significant impact on mercury capture for both native LOI and activated carbon.

In addition to testing the effect of temperature on mercury capture, the Hg project team also tested lower LOI levels by dropping boiler load from 85 MW to 65 MW. In general, by reducing boiler load from 85 MW to 65 MW, this decreased the LOI level from the 25-30% range to 15-20%. This change in LOI levels didn't appear to have a significant impact on native mercury removal at the elevated temperatures of >320°F.

The following week, Unit 1 was placed at full load (85 MW) and at normal operating conditions. At these normal operating conditions, air heater outlet temperatures were approximately 300°F

as measured by the Hg S-CEM. At these testing conditions, activated carbon was injected into the flue gas just down stream of measurement location #1. Three different injection concentrations were tested 5, 10, and 20 lbs/MMacf respectively, and vapor phase mercury concentrations were measured at locations #1 and #3 during all three injections.

Through out this data analysis process, it has been rather difficult to develop trends between the two weeks of testing during the parametric testing series. In some cases it's been difficult to develop trends from day to day with so many variables changing through out the system. Different coals being fired, different LOI levels in the system, adjusting temperatures, and varying Hg levels in the system have made data analysis very challenging. In general the Hg project team has determined that temperature and LOI play a significant role in the mercury capture at Salem Harbor. At the elevated temperatures, vapor phase mercury is harder to capture than compared to the lower temperatures. Further analysis is needed to better understand the impacts of increased temperature and varying LOI has on mercury capture at the Salem Harbor station.

During the parametric testing series ESP fly ash and coal samples are collected daily by plant personnel. These samples are then transferred to ADA-ES personnel where they are logged in the database and packaged for shipping. Coal samples from a few select days will be analyzed for mercury content and this will give the Hg project team an idea of how much mercury should be seen through out the system. Table 1 below represents the fly ash and coal sampling schedule during the parametric testing series.

Table 1. Coal and Fly Ash Sampling Schedule for Salem Harbor – SNCR Off/On Tests

Date	Coal					Fly Ash							
	Feeders					ESP (Testing Chamber)				ESP (Control Chamber)			
	1-1	1-2	1-3	1-4	Composite	A- Row	B- Row	C-Row	D-Row	A-Row	B-Row	C-Row	D-Row
7-Oct		A				A	A	A	A				
8-Oct		A				A	A	A	A				
9-Oct		A				A	A	A	A	A	A		
10-Oct		A				A	A	A	A	A	A		
11-Oct		A				A	A	A	A				
12-Oct													
13-Oct													
14-Oct		A				A	A	A	A	A	A		
15-Oct		A				A	A	A	A				
16-Oct		A				A	A	A	A				
17-Oct		A				A	A	A	A	A	A		
18-Oct		A				A	A	A	A				

A – 1 Liter Sample

Week of November 4, 2002: Long-Term Testing Series

The long term testing series begins on November 4. After preliminary analysis of the data collected during the baseline and parametric testing series, the testing conditions have been revised. Salem Harbor station will return to firing its standard coal and a performance curve will be developed at three different injection concentrations 5, 10, and 20 lbs/MMacf. This data will be compared to the data collected from the parametric testing series, and this will develop an

understanding of how different coals behave differently in regards to mercury control. After further analysis, there appears to be a temperature threshold in which native LOI is ineffective for mercury capture, however activated carbon still has the ability to capture vapor phase mercury at the same temperature. The test schedule and testing conditions are waiting for approval from the appropriate PG&E Salem Harbor plant personnel. Once the Hg project team has approval from the plant, the revised testing schedule will be released.

Once again, the field test data collected has brought forth some rather interesting and exciting results. If anyone has any questions or concerns about results or observations witnessed please contact Travis Starns.

Office: 303.734.1727
Cell: 303.881.6154

traviss@adaes.com

APPENDIX E

LONG-TERM TESTS

November 27, 2002

ADA Environmental Solutions, LLC

8100 SouthPark Way, B-2
Littleton, Colorado 80120
Fax: 303.734.0330
***303.734.1727** or 1.888.822.8617*

Memorandum

To: Jean Bustard, Doug Bondar, Mike Kane, Allen Sload, Ramsay Chang, Sharon Sjostrom, Rui Afonso, Sheila Haythornthwaite, Steve Johnson, Hg Project Team

From: Travis Starns

CC: Mike Durham, Cam Martin, Brian Donnelly

Date: November 27, 2002

RE: Preliminary Results from Long-Term Testing Series

Note: These data are preliminary and confidential to Salem Harbor Hg project team members.

Primary Goals for Parametric Testing Series:

1. Determine the speciation of mercury at four different locations throughout the system.
2. Place steam coils into service and determine the effect of increasing flue gas temperature at the ESP inlet has on native mercury removal.
3. Inject activated carbon into the flue gas and determine the sorbent's performance for mercury capture at the increased flue gas temperature.
4. Inject activated carbon at different injection concentrations (lbs/MMacf) and develop a performance curve for activated carbon at different injection concentrations.
5. Collect ash and coal samples from Unit 1.
6. Determine vapor phase Hg concentrations upstream of the air heater (Location #0).
7. Injected activated carbon continuously (24 hours/day) for a period of 4 days and monitor vapor phase mercury concentrations throughout the system.
8. Measure mercury content in the flue gas via the test Ontario Hydro method.
9. Determine metals content in the flue gas via the Method 29 testing protocol.
10. Measure chlorine and ammonia content in the flue gas at the air heater outlet location.

Completed Tasks:

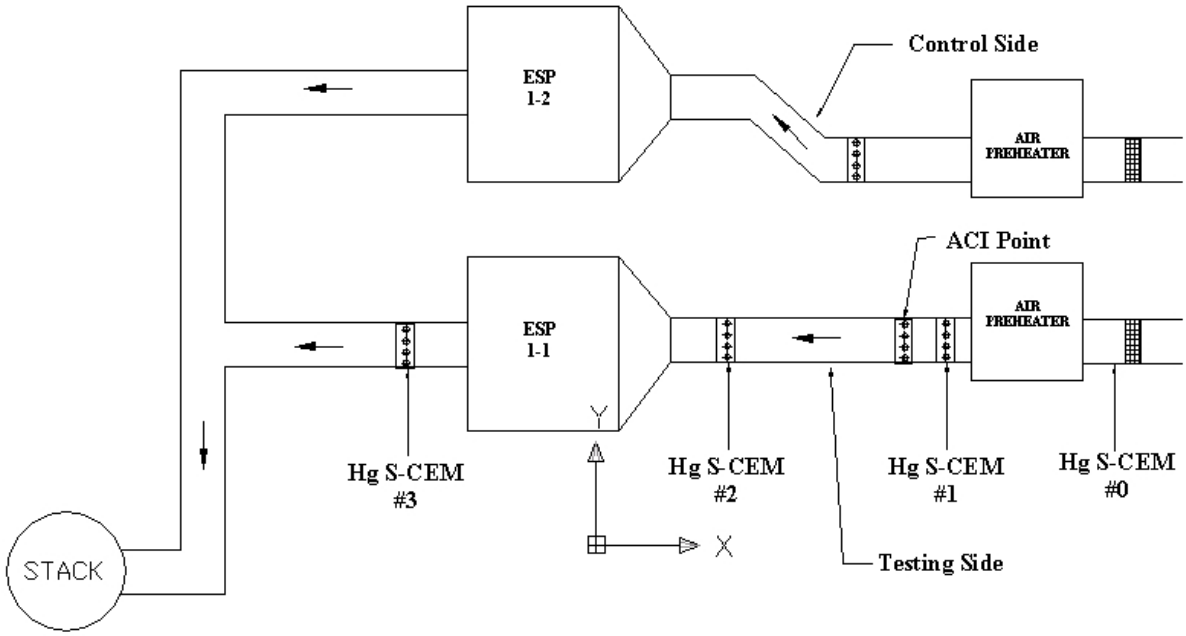
1. Measured the elemental and total vapor phase mercury concentrations at four different locations throughout the system including upstream of the air heater.
2. Raised air heater outlet temperatures by approximately 25°F and measured vapor phase mercury concentrations.
3. Injected activated carbon at two different injection concentrations and determined the overall removal efficiency of vapor phase mercury.
4. Injected activated carbon continuously (24 hours/day) for a period of four days at an injection concentration of 10 lbs/MMacf.
5. Documented and logged all coal and ash samples collected during the long-term testing series.
6. Conducted triplicate runs of the Ontario Hydro testing method as well as triplicate runs of the Method 29 testing protocol.

7. Measured the chlorine and ammonia content in the flue gas at the air heater outlet location.

Results and Comments:

Prior to the start of activated carbon injection (ACI), elemental and total vapor phase mercury measurements were made throughout the system. These measurements were taken at four different locations, which can be seen by the Hg S-CEM locations noted below in figure 1.

Figure 1. Hg S-CEM locations at Salem Harbor Unit 1



The Hg project team is currently reviewing the data collected from the long term testing series. However, it can be stated that a vast majority of the vapor phase mercury measured at the ESP outlet was in the elemental form. Once the data has been completely reviewed, actual mercury concentration data will be released to the Hg team.

It is worth noting, that during the long-term testing series vapor phase mercury concentrations were extremely low throughout the system. Upstream of the air heater, vapor phase mercury levels ranged from 1-4 μg/dNm^3. At the ESP outlet location, vapor phase mercury concentrations ranged from 0.1 – 0.6 μg/dNm^3. Coal samples were collected each day, and these samples will be measured for Hg content. Data from the mercury analyzers will then be compared to the coal data. During the parametric testing series, the data from the coal matched Hg analyzer data at the air heater inlet location.

After collecting speciation data, the steam coils were placed into service and ESP inlet temperatures were increased by an average of 25°F, thus raising ESP inlet temperatures to approximately 325°F. With the flue gas temperatures increased and mercury levels reaching thermal equilibrium, the Hg project team performed ACI at two different injection rates, 10 and 20 lbs/MMacf respectively. Actual mercury removal efficiencies for these two data points are still being analyzed, but preliminary analysis shows the long-term data matches the parametric results.

After performing ACI at two different injection rates, the decision was made to inject activated carbon continuously for 24 hours a day for a period of approximately 4 days. The sorbent

injection rate was set to 10 lbs/MMacf or 105 lbs/hr. During this time, vapor phase mercury measurements were made throughout the system including speciation data as well.

After two days of continuous injection, mercury content was measured in the flue gas via the test Ontario Hydro method. Triplicate runs of the Ontario Hydro method were performed at Locations 1 and 3, which can be seen in Figure 1 above. In addition to the Ontario Hydro, a metals content was determined at the same locations using the CFR Promulgated Test Method 29. Once the Ontario Hydros and Method 29s were complete. Chlorine and ammonia measurements were made at location 1. This particular data is not yet available.

Plant personnel collected coal and fly ash samples daily, and these samples will be sent off for lab analysis. For a complete schedule and sampling locations, please see Table 1 below.

Table 1. Coal and Fly Ash Sampling Schedule for Salem Harbor – LongTerm

Date	Coal					Fly Ash							
	Feeders					ESP (Test Chamber)				ESP (Control Chamber)			
	1-1	1-2	1-3	1-4	Composite	A- Row	B- Row	C-Row	D-Row	A-Row	B-Row	C-Row	D-Row
16-Nov		A				A	A	A	A				
17-Nov		A				A	A	A	A				
18-Nov		A				A	A	A	A				
19-Nov		A				A	A	A	A	A	A		
20-Nov	A	A	A	A		A, 2B	A, 2B	A,B	A,B				
21-Nov	A	2A	A	A		A, 2B	A, 2B	A,B	A,B				
22-Nov	A	2A	A	A		A,2B	A,2B	A,B	A,B				

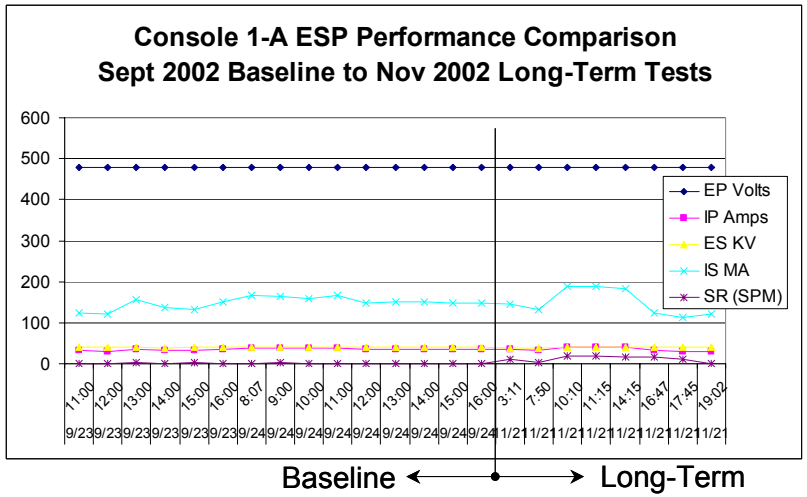
A – 1 Liter Sample
B – 5 Gallon Sample

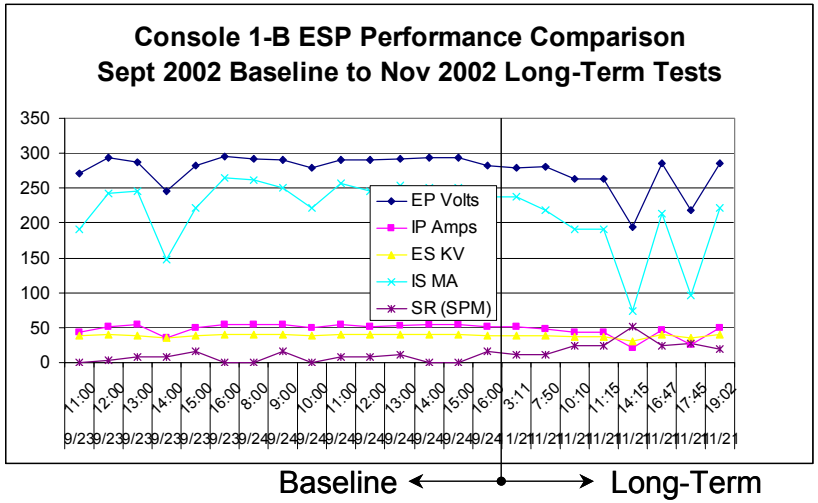
Preliminary analysis of the data collected during the long-term testing series is representative of the results seen during the parametric tests. Once this data has been completely reviewed, a memo containing actual removal efficiencies and mercury concentrations will be released at a later date. If anyone has any questions or concerns about results or observations witnessed please contact Travis Starns.

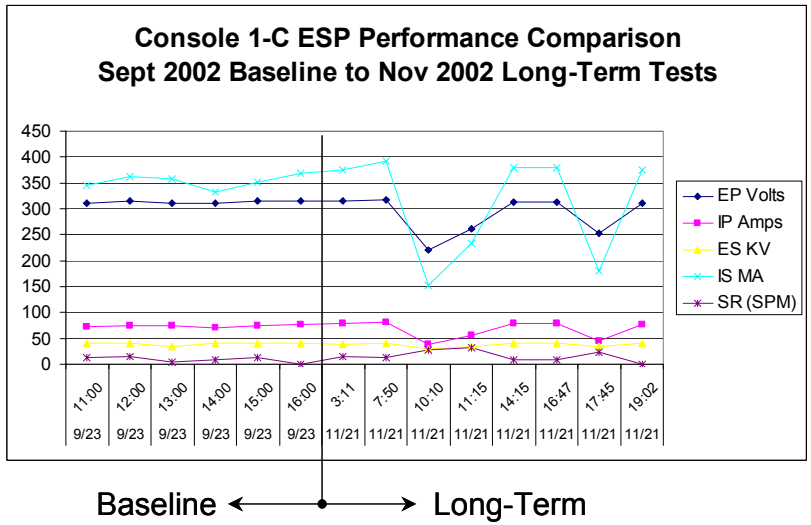
Office: 303.734.1727
Cell: 303.881.6154

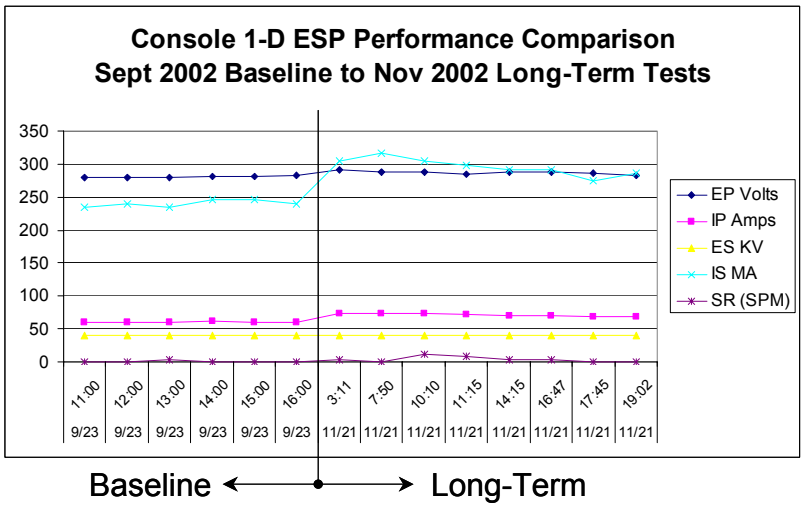
traviss@adaes.com

Salem Harbor ESP Performance Graphs

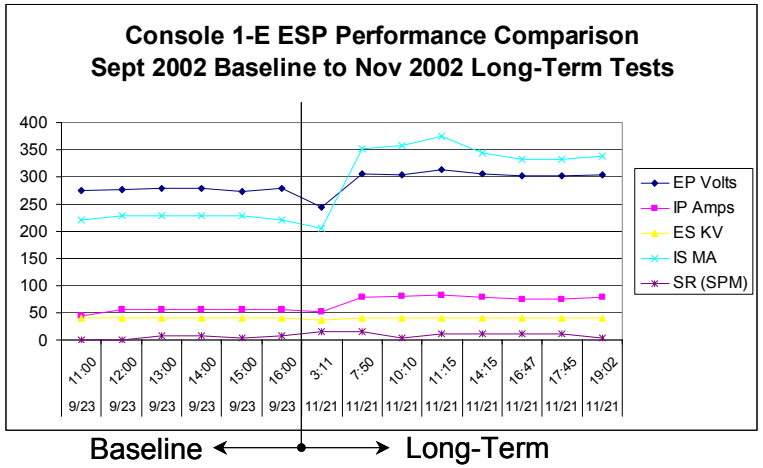


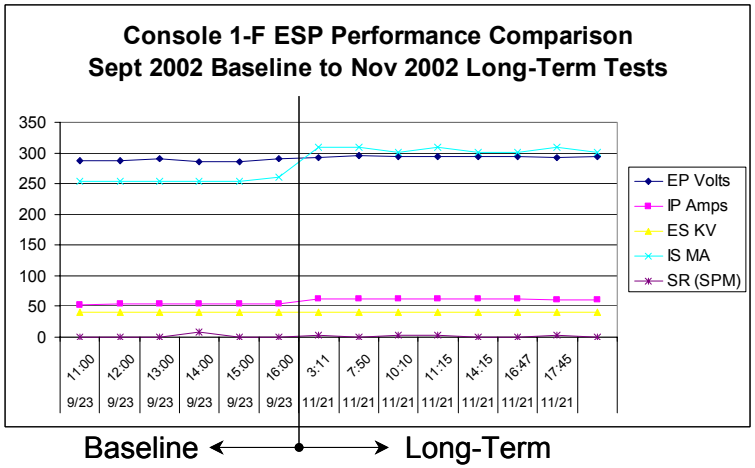


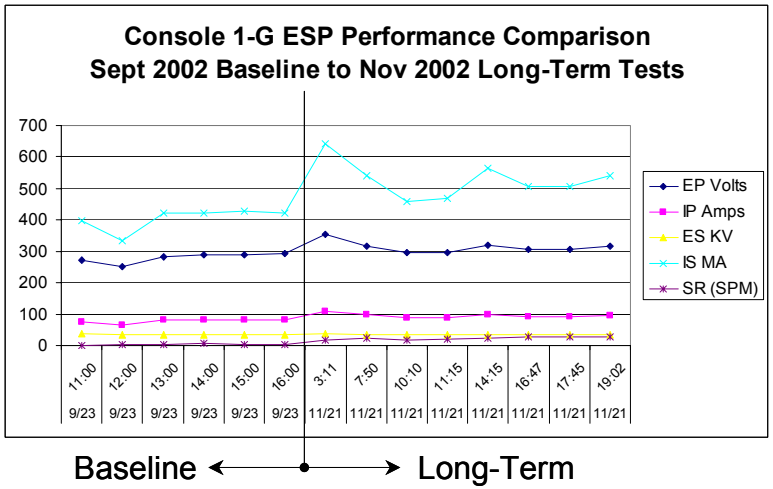


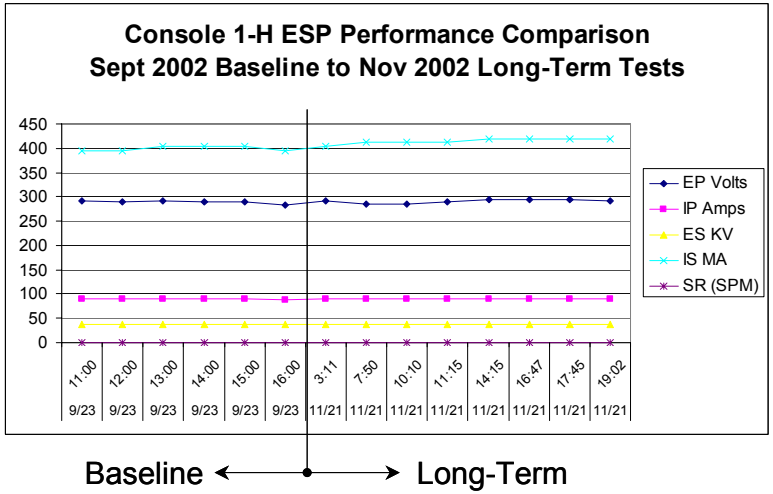


Salem Harbor ESP Performance Graphs (Continued)









APPENDIX F

ANALYSIS OF FLY ASH AND COAL

Date: October 1, 2003

From: Connie Senior

To: C. Jean Bustard, Sheila Glesmann, Travis Starns

Re: FINAL Analysis of Salem Harbor Coal and Ash Data

Table 1 shows the analyses conducted on the samples from baseline, parametric and long-term testing.

Coal Samples

The standard coal burned by the plant was a low-sulfur bituminous coal. During the parametric testing a different low-sulfur bituminous coal (Drummond coal) was fired. Full coal composition analysis was carried out on eight coal samples, as shown in Table 2. Additional mercury analyses were carried out on more coal samples during the baseline and parametric testing to assess the uniformity of the mercury content. The results of mercury and chlorine analyses for all coals samples are given in Table 3. The coal analyses in the tables refer to the standard coal unless otherwise noted. The equivalent mercury concentration in the flue gas at 3% O_2 can be estimated from the coal analyses given in Table 2, since most of the coals in Table 3 where not analyzed for elemental composition. The coal samples had mercury contents in the range of 0.05 to 0.16 μg/g (5 to 16 μg/dnm^3 at 3% O_2). Chlorine contents for the standard coal were generally low (50 to 150 μg/g) but there was one outlier on 11/19/02 that had almost 600 μg/g Cl (dry basis). The Drummond coal had lower chlorine (~20 μg/g), based on one sample.

Several of the standard coal samples were analyzed for other trace metals, as shown in Table 4. The content of the four metals is consistent among the samples. The arsenic content of the coal is fairly low, as compared to US bituminous coals.

During the baseline and parametric testing, mercury concentration in flue gas as measured by the SCEM occasionally got very high. In order to determine whether these observed spikes were typical, the daily mercury values from the coal are plotted in Figure 1. The coal mercury content was fairly consistent at about 0.07 μg/g on a dry basis (~7 μg/dnm^3 at 3% O_2), but there were occasional spikes of mercury in the coal to double that amount.

Table 1. Analyses carried out on samples.

ADA ES ID	MTI ID	Date	Sample	Sample Location	Analyses
SH00037	02-192	9/17/2002	Ash	B-Row	Hg, Cl, NH3, LOI (, TPD at URS)
SH00043	03-119	9/18/2002	Ash	B-Row	Hg, Cl, NH3, LOI
SH00045	03-120	9/18/2002	Ash	D-Row	Hg, Cl, NH3, LOI
SH00050	03-121	9/19/2002	Ash	D-Row	Hg, Cl, NH3, LOI
SH00057	03-122	9/23/2002	Ash	B-Row	Hg, Cl, NH3, LOI (, TPD at URS)
SH00070	02-193	9/24/2002	Ash	A-Row	Hg, NH3, LOI, Cl, metals, TCLP, SGLP
SH00072	02-195	9/24/2002	Ash	C-Row	Hg, NH3, LOI
SH00073	02-196	9/24/2002	Ash	D-Row	Hg, NH3, LOI
SH00076	03-123	9/24/2002	Ash	B-Row	Hg, Cl, NH3, LOI (, TPD at URS)
SH00098	03-124	9/26/2002	Ash	A-Row	Hg, Cl, NH3, LOI
SH00099	03-125	9/26/2002	Ash	B-Row	Hg, Cl, NH3, LOI
SH00100	03-126	9/26/2002	Ash	C-Row	Hg, Cl, NH3, LOI
SH00103	03-129	9/27/2002	Ash	A-Row	Hg, Cl, NH3, LOI
SH00104	03-130	9/27/2002	Ash	B-Row	Hg, Cl, NH3, LOI
SH00133	03-131	10/11/2002	Ash	A-Row	Hg, Cl, NH3, LOI
SH00134	03-132	10/11/2002	Ash	B-Row	Hg, Cl, NH3, LOI
SH00135	03-133	10/11/2002	Ash	C-Row	Hg, Cl, NH3, LOI
SH00136	03-134	10/11/2002	Ash	D-Row	Hg, Cl, NH3, LOI
SH00161	02-194	10/30/2002	Ash	B-Row replaces SH00071	Hg, NH3, LOI
SH00184	03-021	11/19/2002	Ash	A-Row	Hg, LOI
SH00185	03-020	11/19/2002	Ash	A-Row (Control)	Hg, LOI, NH3, metals, SA, PSD, Pore size distr., leaching (EERC)
SH00187	03-022	11/19/2002	Ash	B-Row	Hg, LOI
SH00188	03-023	11/19/2002	Ash	C-Row	Hg, LOI
SH00189	03-024	11/19/2002	Ash	D-Row	Hg, LOI
SH00195	03-026	11/20/2002	Ash	A-Row	Hg, LOI, Cl, NH3, SA, PSD, Pore size distr., metals, leaching (EERC)
SH00198	03-027	11/20/2002	Ash	B-Row	Hg, LOI, Cl, NH3, SA, PSD, Pore size distr.
SH00201	03-028	11/20/2002	Ash	C-Row	Hg, LOI, Cl, NH3, SA, PSD, Pore size distr.
SH00203	03-029	11/20/2002	Ash	D-Row	Hg, LOI, Cl, NH3, SA, PSD, Pore size distr.
SH00209	03-031	11/21/2002	Ash	A-Row	Hg, LOI, leaching (DOE)
SH00223	03-033	11/22/2002	Ash	A-Row	Hg, LOI, metals, leaching (EERC), leaching (EPA)
SH00035	02-182	9/16/2002	Coal		Hg
SH00040	02-183	9/17/2002	Coal		Hg, Cl
SH00041	02-184	9/18/2002	Coal		Hg
SH00042	02-185	9/19/2002	Coal		Hg, Cl
SH00054	03-097	9/23/2002	Coal		Ult, Prox, Hg, Cl
SH00101	03-127	9/26/2002	Coal	3:15 PM	Hg, Cl
SH00102	03-128	9/27/2002	Coal		Hg, Cl

ADA ES ID	MTI ID	Date	Sample	Sample Location	Analyses
SH00125	02-189	10/9/2002	Coal		Ult, Prox, Hg, Cl
SH00149	02-190	10/16/2002	Coal		Hg
SH00183	03-025	11/19/2002	Coal	Feeder 1-2	Ultimate, Proximate, Hg, Cl, metals
SH00192	03-030	11/20/2002	Coal	Feeder 1-2	Ultimate, Proximate, Hg, Cl, metals
SH00206	03-032	11/21/2002	Coal	Feeder 1-2	Ultimate, Proximate, Hg, Cl
SH00219	03-034	11/22/2002	Coal	Feeder 1-2	Ultimate, Proximate, Hg, Cl, metals
SH00233	02-186	9/24/2002	Coal		Ult, Prox, Hg, Cl, metals
SH00234	02-187	9/25/2002	Coal		Ult, Prox, Hg, Cl
SH00235	02-188	9/26/2002	Coal		Hg

Table 2. Coal Analyses.

	Baseline/Parametric Testing				Long-term Testing			
ADA ES ID	SH00054	SH00233	SH00234	**SH00125***	SH00183	SH00192	SH00206	SH00219
MTI ID	03-097	02-186	02-187	*02-189*	03-025	03-030	03-032	03-034
Date	9/23/2002	9/24/2002	9/25/2002	*10/9/2002*	11/19/2002	11/20/2002	11/21/2002	11/22/2002
ULTIMATE ANALYSIS (As Received):								
Carbon	73.84	72.37	70.28	*69.01*	71.38	71.76	73.84	73.38
Hydrogen	5.37	4.74	4.57	*4.47*	4.56	4.54	4.54	4.69
Oxygen	13.87	6.32	7.62	*9.83*	7.04	7.94	8.59	8.41
Nitrogen	1.35	1.43	1.33	*1.33*	1.29	1.27	1.44	1.53
Sulfur	0.82	0.56	0.67	*0.56*	0.59	0.56	0.65	0.61
Ash	4.75	6.30	6.48	*4.16*	6.06	3.72	3.20	3.63
Moisture	6.75	8.28	9.05	*10.64*	9.08	10.21	7.74	7.75
Hg, µg/g	0.066	0.065	0.070	*0.055*	0.066	0.043	0.065	0.057
Cl, µg /g	139.88	89	136	*21*	545	171	47	59
HHV, Btu/lb	12,843	12,715	12,420	*12,114*	12,510	12,593	12,901	12,866
SO_2, lb/MBtu	1.28	0.88	1.08	*0.92*	0.94	0.89	1.01	0.95
Ash, lb/MBtu	3.70	4.95	5.22	*3.43*	4.84	2.95	2.48	2.82
Hg, lb/TBtu	5.16	5.08	5.62	*4.52*	5.31	3.44	5.04	4.42
Hg, µg /dnm^3 ($3\%O_2$)	7.06	6.92	7.76	*6.30*	7.29	4.80	7.00	6.11
PROXIMATE ANALYSIS (As Received):								
Fixed Carbon	43.81	50.04	50	*49*	52.49	52.13	54	53
Volatile matter	44.69	35.38	35	*36*	32.37	33.94	35	36
Ash	4.75	6.3	6.48	*4.16*	6.06	3.72	3.2	3.63
Moisture	6.75	8.28	9.05	*10.64*	9.08	10.21	7.74	7.75

* Drummond coal used for parametric tests only

Table 3. Mercury and chlorine analyses of coal samples.

ADA-ES #	MTI #	Date	Hg, µg/g*	Cl, µg/g*	Hg, µg/dnm^3 (3%O_2)
SH00035	02-182	16-Sep-02	0.0681	-	6.7
SH00040	02-183	17-Sep-02	0.0731	110.0	7.2
SH00041	02-184	18-Sep-02	0.1540	-	15.1
SH00042	02-185	19-Sep-02	0.0808	78.0	8.0
SH00054	03-097	23-Sep-02	0.0710	150.0	7.1
SH00233	02-186	24-Sep-02	0.0704	97.0	6.9
SH00234	02-187	25-Sep-02	0.0767	150.0	7.5
SH00235	02-188	26-Sep-02	0.1628	-	16.0
SH00101	03-127	26-Sep-02	0.0385	90.0	
SH00102	03-128	27-Sep-02	0.0631	35.0	
SH00125**	02-189	09-Oct-02	0.0613	23.0	6.0
SH00149**	02-190	16-Oct-02	0.0551	-	5.4
SH00183	03-025	11/19/2002	0.0731	599.0	7.3
SH00192	03-030	11/20/2002	0.0483	191.0	4.8
SH00206	03-032	11/21/2002	0.0705	50.6	7.0
SH00219	03-034	11/22/2002	0.0617	64.3	6.1

* Dry basis

** Drummond coal used for parametric tests only

Table 4. Trace metal contents of coal samples (dry basis).

ADA-ES #	MTI #	Date	As, µg/g	Cd, µg/g	Pb, µg/g	Se, µg/g
Composite	02-186	9/24/2002	1.4	0.17	3.4	5.4
SH00183	03-025	11/19/2002	1.7	0.10	5.8	4.7
SH00192	03-030	11/20/2002	1.0	0.12	4.7	6.1
SH00219	03-034	11/22/2002	2.4	0.14	3.8	4.8

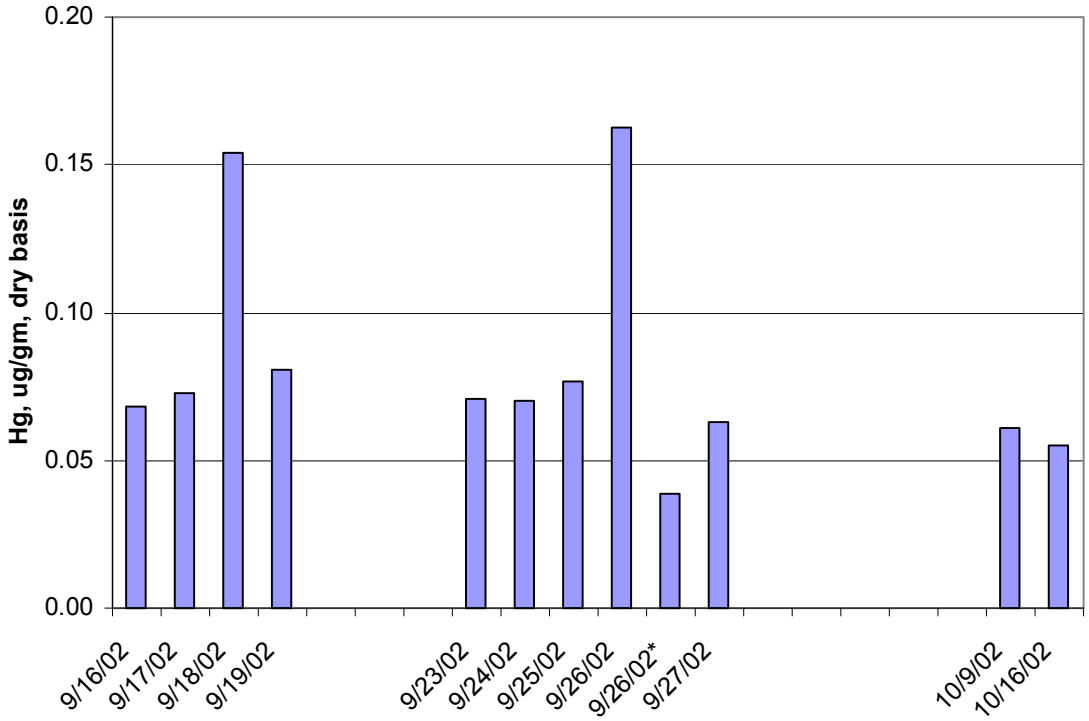


Figure 1. Coal mercury content in µg/g, dry basis.

Ash Samples

Ash samples were taken from the ESP hoppers and analyzed for mercury, ammonia, chloride and LOI; these data are summarized in Table 5. During the testing the hoppers were continuously emptied, so the ash samples should reflect current conditions. The rows labeled A through D correspond to fields that go from the front to the back of the ESP. The A and B Rows are typical of the bulk ash. Comparatively less material is collected in the C and D Rows. From the pre-baseline testing at Salem Harbor in 2001, we know that the C and D Rows contain more large, high-carbon particles, which may be due to particle re-entrainment from the front fields.

Ash samples were taken from the ESP hoppers during the baseline and parametric testing to understand the effects of operating conditions and coal selection on mercury removal and on ash properties. Ash samples were not taken during the parametric testing of PAC injection. During long-term testing one ash sample was taken from the A Row of the control chamber (no sorbent injection). This is called "A-Row (control)."

Table 5. Ash Analyses

ADA ES ID	MTI ID	Date	Sample Location	Hg, µg/g	NH_3, µg/g	Cl, µg/g	LOI, wt%	SA, m^2/g
SH00037	02-192	9/17/2002	B-Row	0.477	322	30	50.9	
SH00043	03-119	9/18/2002	B-Row	0.399	230	17.5	51.4	
SH00045	03-120	9/18/2002	D-Row	0.698	2830	48.2	83.2	
SH00050	03-121	9/19/2002	D-Row	0.621	5720	45.5	80.3	
SH00057	03-122	9/23/2002	B-Row	0.477	248	22.2	48.5	
SH00070	02-193	9/24/2002	A-Row	0.4	239	<5	21	
SH00076	03-123	9/24/2002	B-Row	0.576	350	15.7	44.3	
SH00161	02-194	10/30/2002	B-Row*	0.685	305		43.7	
SH00072	02-195	9/24/2002	C-Row	0.968	766		66.8	
SH00073	02-196	9/24/2002	D-Row	1.27	4490		80.9	
SH00098	03-124	9/26/2002	A-Row	0.565	1080	11.8	20.3	
SH00099	03-125	9/26/2002	B-Row	0.773	1740	18.7	26.8	
SH00100	03-126	9/26/2002	C-Row	1.04	2930	29.1	37.4	
SH00103	03-129	9/27/2002	A-Row	0.416	854	<5	12.3	
SH00104	03-130	9/27/2002	B-Row	0.83	1010	7	20.6	
SH00133	03-131	10/11/2002	A-Row	0.583	702	<5	13.2	
SH00134	03-132	10/11/2002	B-Row	0.703	848	7.9	21.4	
SH00135	03-133	10/11/2002	C-Row	1.27	2560	9.3	18.3	
SH00136	03-134	10/11/2002	D-Row	1.33	7640	17.6	25.5	
SH00185	03-020	11/19/2002	A-Row (control)	0.119	207	7.9	12.6	5.69
SH00184	03-021	11/19/2002	A-Row	0.196			21.9	
SH00187	03-022	11/19/2002	B-Row	0.245			33.1	
SH00188	03-023	11/19/2002	C-Row	0.249			66.2	
SH00189	03-024	11/19/2002	D-Row	0.252			87.4	
SH00195	03-026	11/20/2002	A-Row	0.198	213	103	23.2	28.61
SH00198	03-027	11/20/2002	B-Row	0.2	319	122	40.4	36.08
SH00201	03-028	11/20/2002	C-Row	0.188	641	107	75.3	33.48
SH00203	03-029	11/20/2002	D-Row	0.192	588	149	90.7	39.05
SH00209	03-031	11/21/2002	A-Row	0.28			27.6	
SH00223	03-033	11/22/2002	A-Row	0.371			24.7	

*replaces SH00071

Effect of Temperature and Load (no PAC)

During the September baseline testing the load and temperature at the ESP were varied. At full load, the ESP temperature was approximately 300°F. At low load, the temperature was 280-290°F. During the low load testing, the steam coils were turned on, which increased the temperature at the ESP to about 340°F. There appeared to be differences in LOI with load. Figure 2 shows that the low load conditions had somewhat lower LOI than the full load condition.

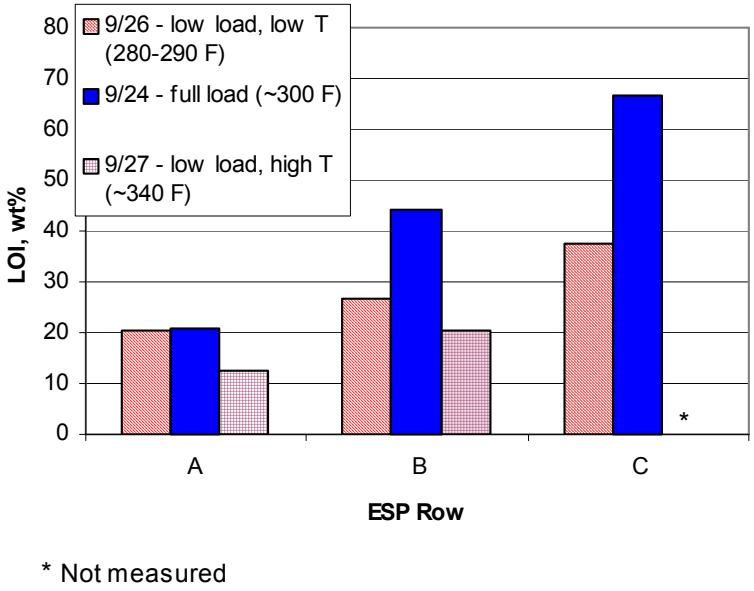
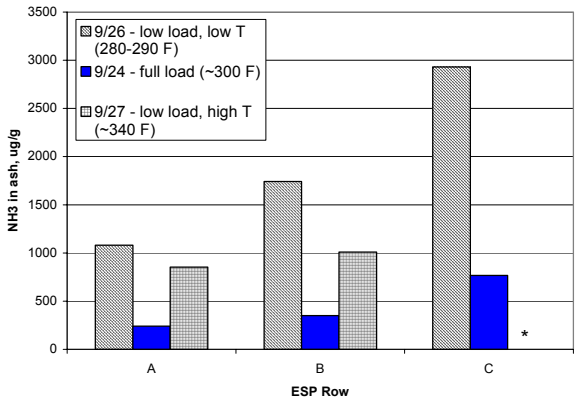


Figure 2. LOI in ESP ash as a function of row for load and temperature variation during baseline testing; no PAC injection.

In spite of the higher LOI at full load, the ash had considerably lower ammonia at full load than at reduced load (Figure 3). This was probably due to differences in urea injection rate as a function of load. There was an effect of temperature on ammonia content of the ash. At a temperature of 340°F the ash picked up less ammonia than at 280-290°F.

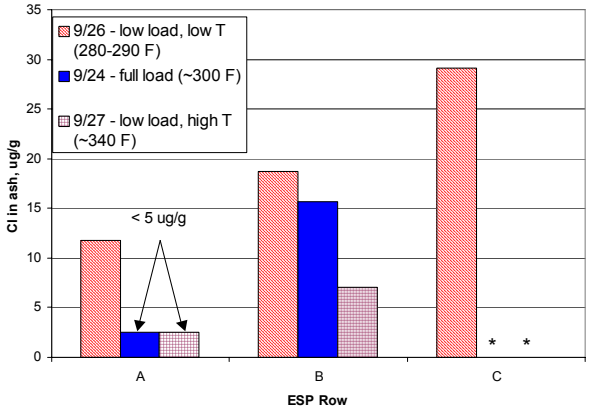
The effect of temperature on the chlorine content of the ash is clear in Figure 4. At 300°F and above, the A-Row ash had no detectable chlorine. At 280-290°F, the chlorine content was about 12 µg/g. Ash from the B-Row did contain measurable chlorine for all three cases and the chlorine content increased as a function of temperature.

Changing load and temperature did not have a clear impact on the mercury content of the ash. The ash from Row A had higher mercury content at the lowest temperature. However, the mercury content of the ash from Row B was highest for low load conditions, irrespective of the temperature. The behavior of the ash from Row A is probably more typical. The mercury *removal* across the ESP was correlated with temperature and decreased as temperature increased.



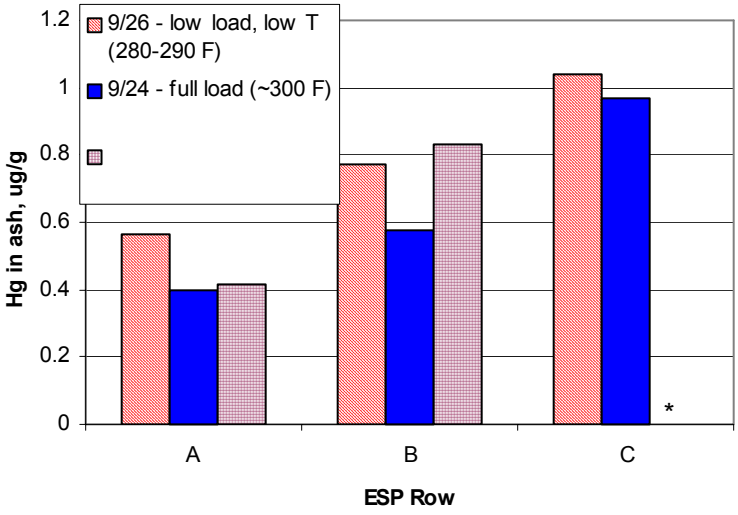
* Not measured

Figure 3. Ammonia in ESP ash as a function of row for load and temperature variation during baseline testing; no PAC injection.



* Not measured

Figure 4. Chlorine in ESP ash as a function of row for load and temperature variation during baseline testing; no PAC injection.



* Not measured

Figure 5. Mercury in ESP ash as a function of row for load and temperature variation during baseline testing; no PAC injection.

Effect of SNCR System (no PAC)

During the baseline testing, the urea was turned off as the plant started up after an outage. Unit 1 came up on 9/16/02 without the SNCR system in operation; the urea was switched on at 1:50pm on 9/18/02. Ash samples were collected on 9/17/02, when the plant had been operating for a day without urea injection, on 9/18/02 *one hour after* the start of urea injection and on 9/19/02 after the urea had been on for a day. There was not any clear effect of urea injection on either the ammonia content of the ash (Figure 6) or the mercury content of the ash (Figure 7). The lack of some correlation between urea injection and ammonia content of the ash is puzzling.

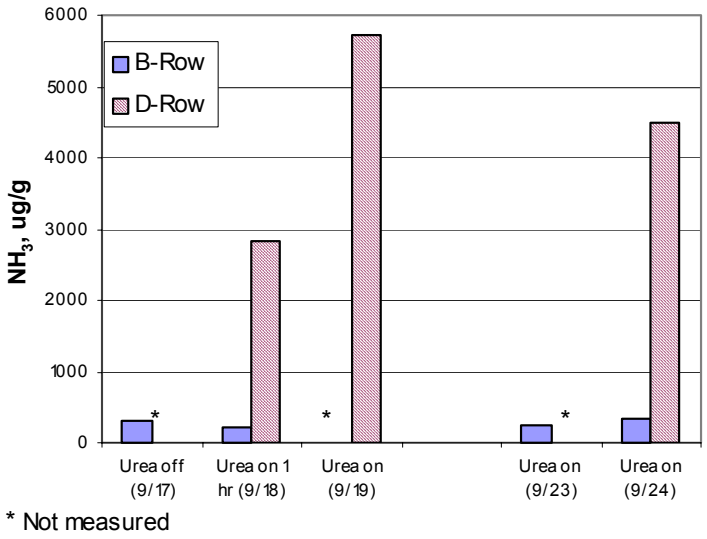


Figure 6. Ammonia content of the ash with and without urea injection in Unit 1; no PAC injection.

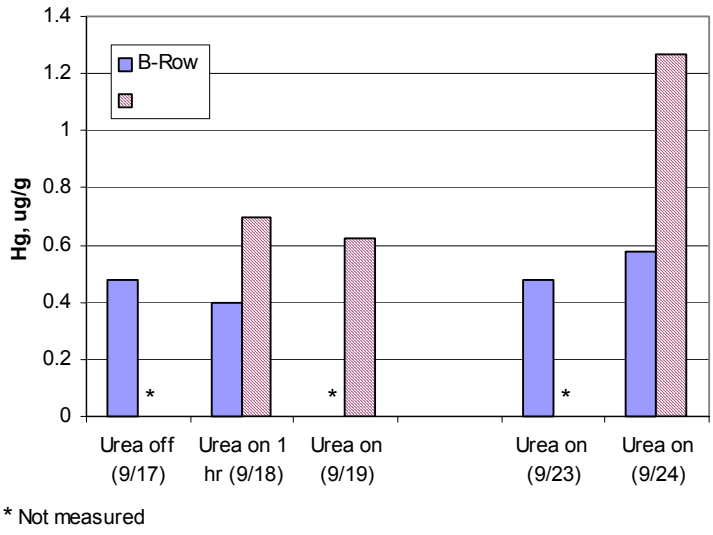


Figure 7. Mercury content of the ash with and without urea injection in Unit 1; no PAC injection.

Effect of Coal (no PAC)

A different coal (Drummond) was fired during the parametric testing in October 2002. Ash from the standard coal produced a distinct increase in LOI, mercury, ammonia and chlorine as a function of row in the ESP. Ash from the Drummond coal was compared to that from the standard coal to see if the same variations in ash properties with row in the ESP were observed.

Ash data from the standard coal comes from samples collected on 9/24/02 with an ESP temperature of about 300°F. The ash samples taken on 10/11/02 were taken with the steam coils on and the ESP temperature was 340-350°F. Ash data from the Drummond coal comes from samples collected at 3:00 pm on 10/11/02. Twelve hours before the ash sample was collected PAC was injected into the duct for a period of four hours; injection was stopped at 5:00 am. The ESP hoppers were continuously emptied; therefore there should not have been much residual sorbent in the ESP hoppers when the ash samples were taken.

LOI measurements made with the hot-foil instrument indicated that the LOI for the standard coal was in the range of 30-40%. LOI was lower for the Drummond coal, in the range of 25-30%. Figure 8 compares the LOI values for the two coals as a function of ESP row. Ash from the A Row (or some combination of ash from A and B Rows) should be indicative of the bulk ash. The standard coal had LOI values ranging from 21% in the A Row to 44% in the B Row. The Drummond coal had LOI values ranging from 13% in the A Row to 21% in the B Row. The ESP hopper data reflects the trend seen in the hot foil data, although it is difficult to compare the two measurements since the sampling methods are different. The Drummond coal does not reproduce the trend of increasing LOI with row in the ESP that has been observed for the standard coal. The LOI from the standard coal ash increases to 80% in the D Row of the ESP. Previous analysis during 2001 showed that this high LOI ash consisted of predominantly larger particles. We

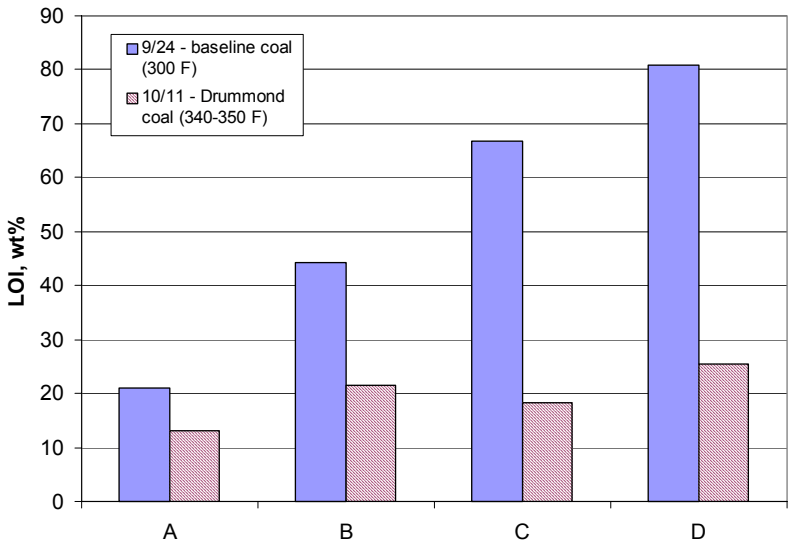


Figure 8. LOI as a function of ESP row during combustion of the standard coal (300°F ESP temperature) and the Drummond coal (340-350°F ESP temperature); no PAC injection.

hypothesized that large unburned carbon particles became re-entrained and ended up in the last field of the ESP. There may be differences in the combustion of the Drummond coal such that is does not produce large unburned carbon particles as does the standard coal. There are other indications that the Drummond coal produces a different char than the standard coal, as discussed below.

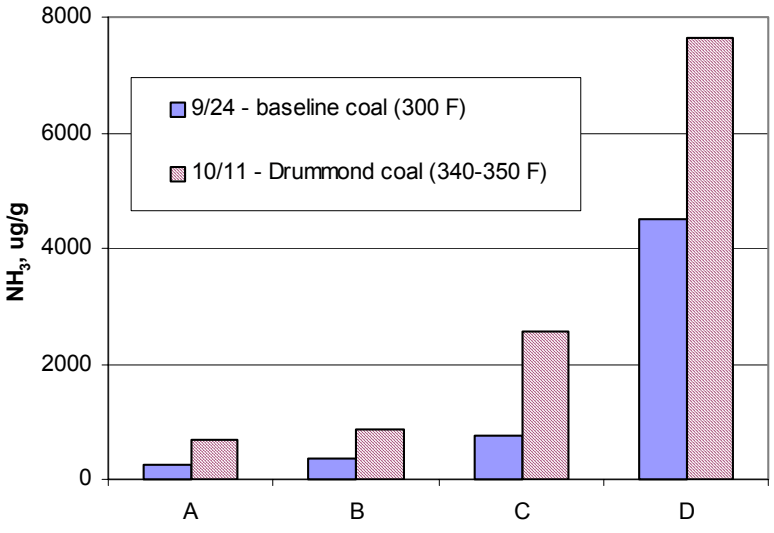


Figure 9. Ammonia content as a function of ESP row during combustion of the standard coal (300^{o}F ESP temperature) and the Drummond coal (340-350^{o}F ESP temperature); no PAC injection.

Figure 9 shows the ammonia content of the ash as a function of row. The ammonia content increases dramatically in the back rows of the ESP for both coals; the Drummond ash shows much higher ammonia content than the standard ash, even though the Drummond ash has a lower LOI and the ESP was hotter. This suggests that the unburned carbon from the Drummond coal is significantly different from the unburned carbon from the standard coal, either in surface area or surface functional groups. There is some possibility that the Drummond ash sample contained residual activated carbon. However, given the way that the ESP hoppers were operated, it seems unlikely that there could have been a significant quantity of activated carbon remaining.

Figures 10 illustrates the relationship between LOI and mercury content for the two coal ash samples. The Drummond ash has a higher affinity for mercury, for a fixed LOI, in spite of the higher temperature of the ESP during firing of the Drummond coal. Without measuring other properties of the ash (surface area, particle size distribution), it is difficult to know why these two similar coals produced such apparently different ash.

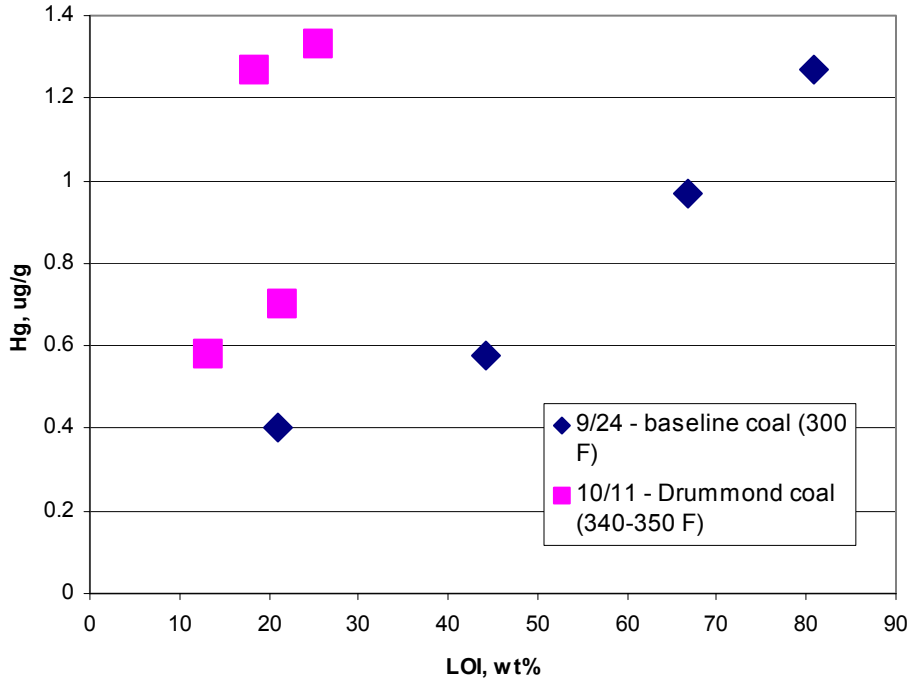


Figure 10. Mercury in ash as a function of LOI during combustion of the standard coal (300°F ESP temperature) and the Drummond coal (340-350°F ESP temperature); no PAC injection.

PAC Injection (Long-term Tests)

The long-term data were taken from 11/19/02 through 11/22/02. It is worth noting that the 11/19/02 coal sample had a fairly typical mercury content, but a high chloride content of about 600 µg/g (dry basis). The 11/20/02 coal sample had a low mercury content.

The LOI values of the long term and baseline tests are comparable (Figure 11). The control sample taken on 11/19/02, however, had lower LOI in the A Row than the sample from the A Row with sorbent injection. This difference is probably more indicative of the effect of sorbent injection than is comparing the baseline sample from 9/24/02 with the sorbent injection sample.

The mercury content of the baseline fly ash was uniformly higher than the long-term fly ash (Figure 12), even though the LOI values were similar. When sorbent was injected, the mercury content of the ash did not increase from the front row to the back row of the ESP as it did during the baseline testing, even though the LOI values were similar. The difference may be because more of the mercury was removed in-flight before the ESP (or in the first row of the ESP) when sorbent was injected. The particle size distribution data discussed below suggest that there are differences in particle size distribution as well.

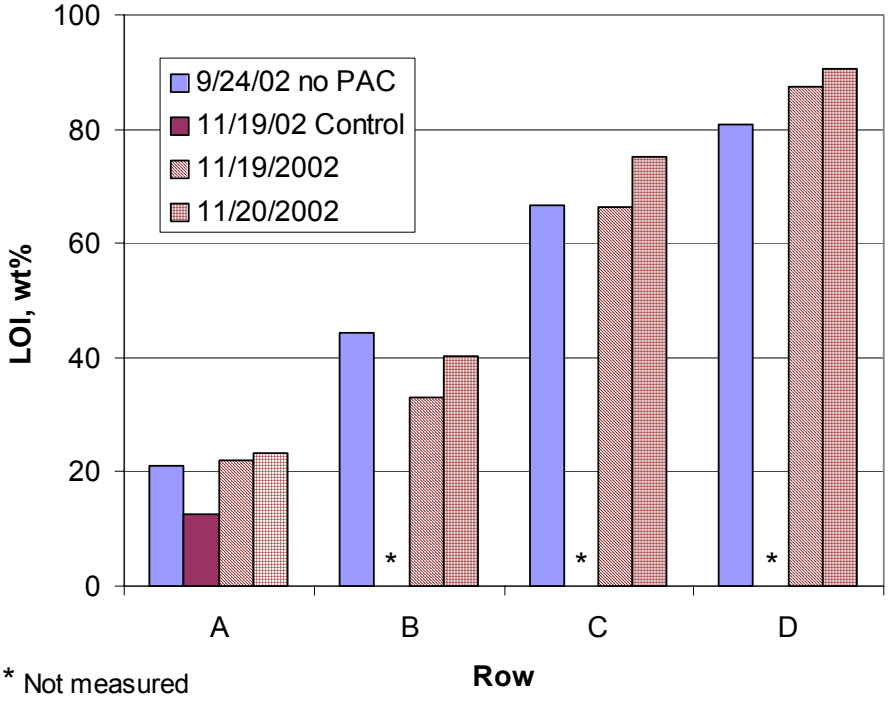


Figure 11. LOI as a function of row in ESP for baseline and long-term testing.

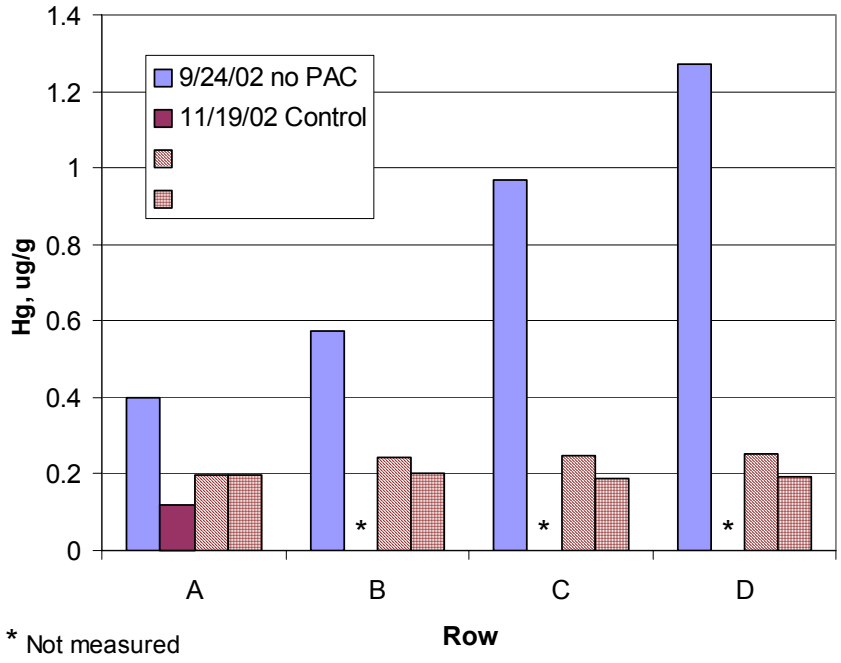


Figure 12. Mercury content as a function of row in ESP for baseline and long-term testing.

Ash was collected from the long-term tests over a period of four days. During this time, PAC was fed continuously at a rate of 10 lb/Macf. Figure 13 shows the trend in LOI in the A Row for successive test days. Sorbent injection resulted in an immediate increase

in the LOI of the ash, as shown by the two leftmost bars, corresponding to the control side and test side chambers of the ESP on 11/19/02. As the test went on, there was a slight increase in the LOI of the ash in the A Row. There was a considerable increase in the mercury content of the coal over the four days, as shown in Figure 14. On the first day of testing, the test side of the ESP showed about 40% more mercury in the ash as compared to the control (no sorbent) side, based on a comparison of the A Rows.

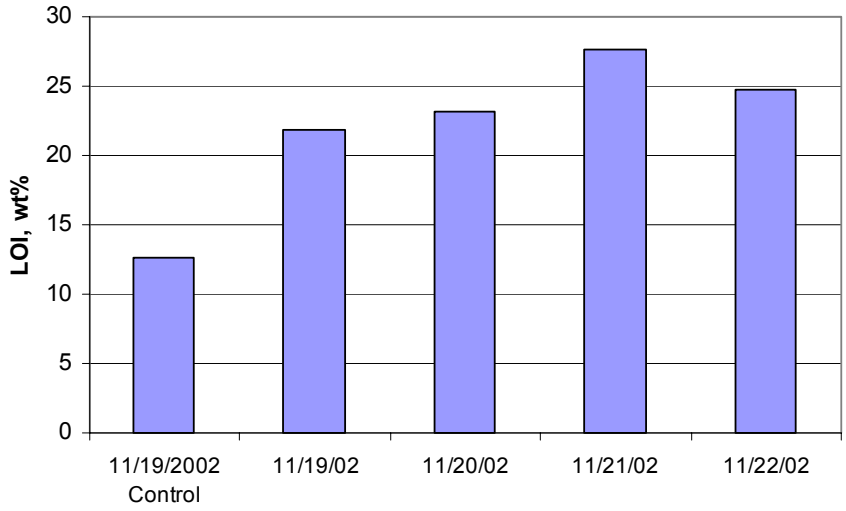


Figure 13. LOI of A-Row ash for long-term testing, beginning on 11/19/02.

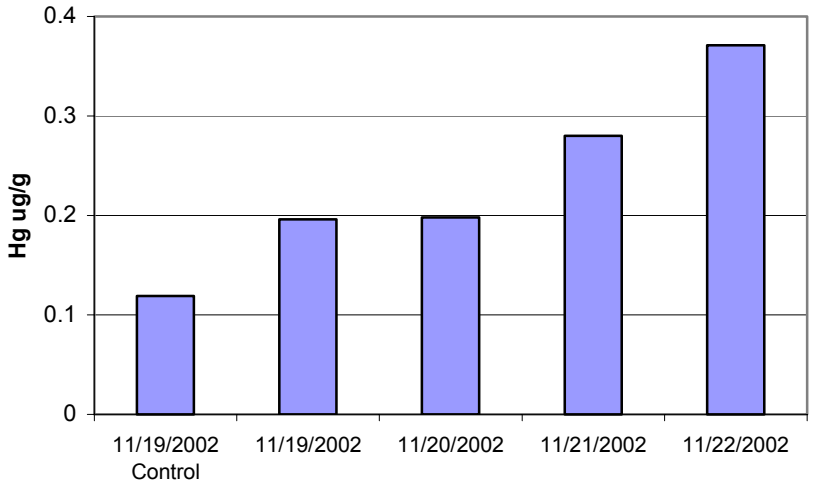


Figure 14. Mercury content of A-Row ash for long-term testing, beginning on 11/19/02.

We can look at the trends within the ESP in the different rows. The baseline and parametric testing showed considerable variation in the properties of the ash among the rows of the ESP. Figure 16 shows the surface area (as calculated from a single-point BET isotherm). Compared to the control side of the ESP, the surface area increases by about a factor of four when PAC is injected. Unlike the LOI, which increases with row, the surface area does not increase much.

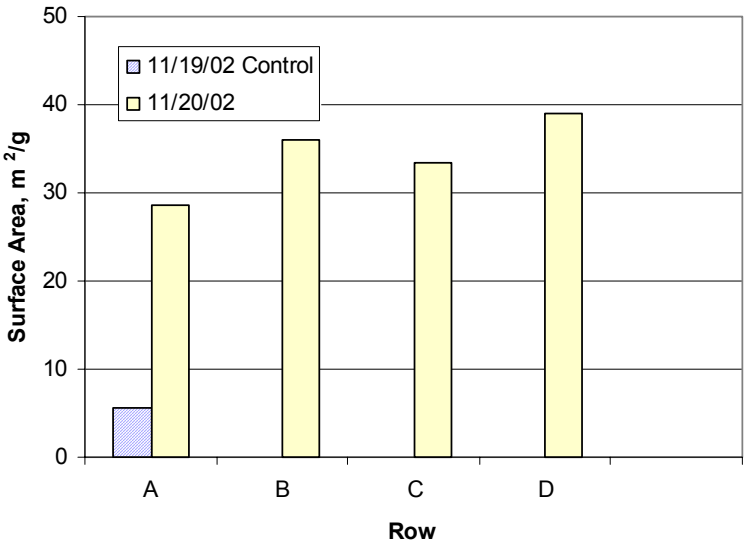


Figure 15.
Specific surface area of ash as a function of row in the ESP.

The size distribution of the ash changes with row of the ESP and with injection of PAC. This is illustrated in Figure 16 in terms of the cumulative volume distribution of the ash, as measured by Malvern analysis. Comparing the A-Rows with and without sorbent, we see a shift in the distribution from 3 μm to 30 μm, which represents the addition of more

mass in this size range, presumably the sorbent. Rows B and C contain larger particles that the A-Row. However, the D-Row contains much finer particles than the other rows. The pore size distributions for the samples shown in Figure 16 are given as an appendix to this report.

The size distribution for the control chamber, A-Row ash is different than the size distribution measured on a sample collected in February 2001 as part of the prebaseline testing. The 2001 sample had a much narrower size distribution. Furthermore, the 2001 D-Row sample had a very coarse particle size distribution, whereas the 2003 D-Row sample, which did contain sorbent, was finer than the A-Row sample—contrary to what was observed in 2001. It is difficult to know if the ESP was performing differently in 2003 as compared to 2001 or if the D-Row sample from 2003 contained a high proportion of fine sorbent particles. Either of these could be a factor in the differences between 2001 and 2003.

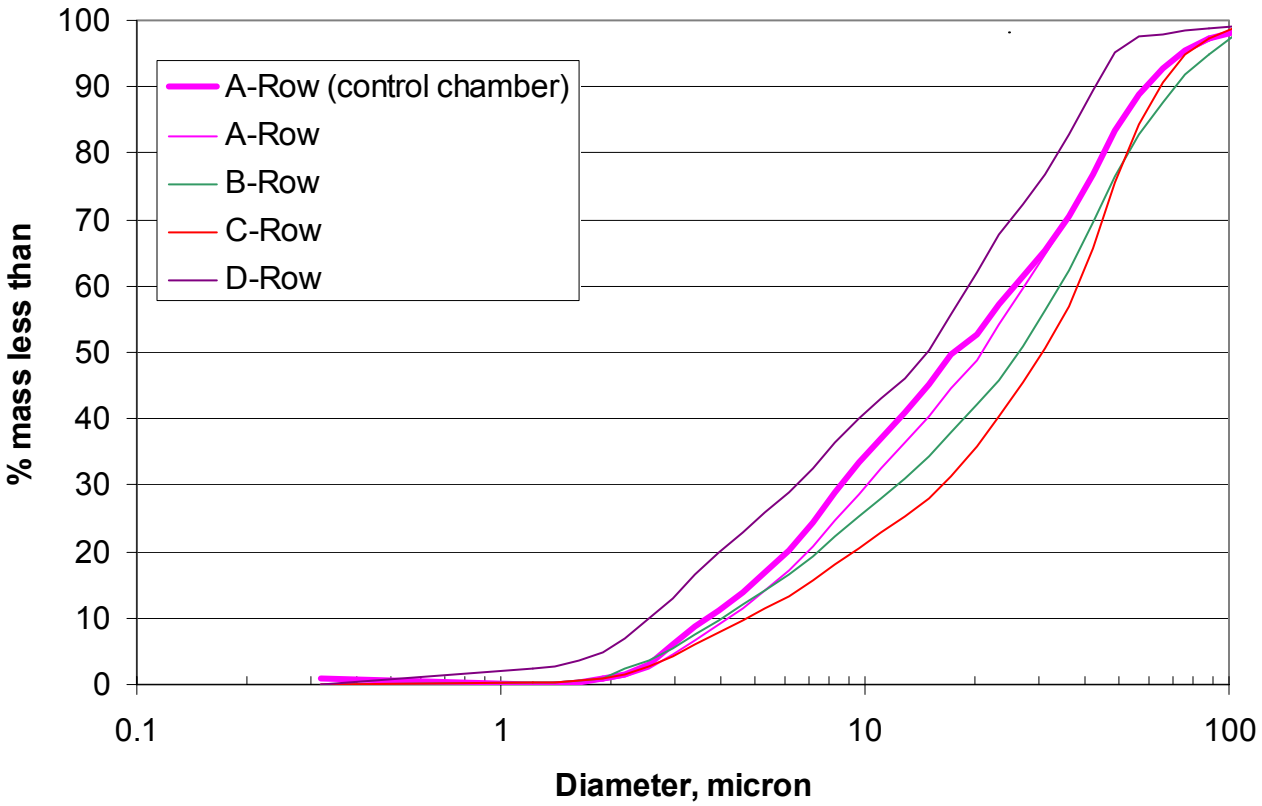


Figure 16. Cumulative volume distribution as a function of ash particle size.

The distribution of chloride in the ash (Figure 17) follows the distribution of surface area: sorbent causes a big increase in chloride in the ash, but the chloride content of the ash is fairly constant across all the rows. Thus, the PAC appears to adsorb chloride, and much more efficiently than the native ash.

The distribution of ammonia in the ash (Figure 18), however, follows the distribution of the LOI. This suggests that the native fly ash adsorbs ammonia, particularly in the back rows of the ESP and this is not affected by the addition of PAC.

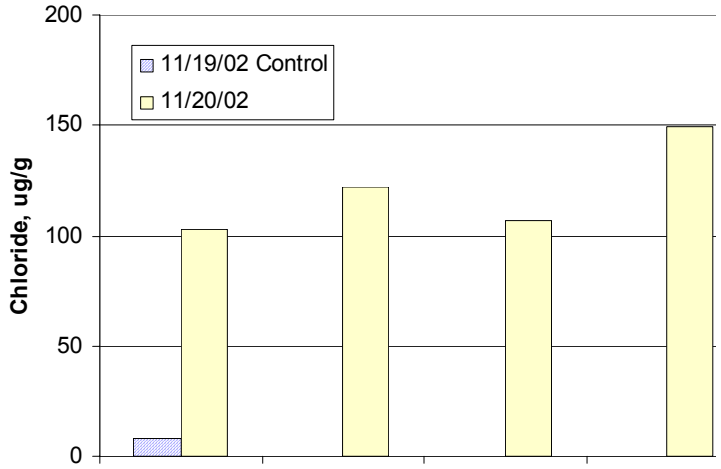


Figure 17. Chloride content of ash as a function of row in the ESP.

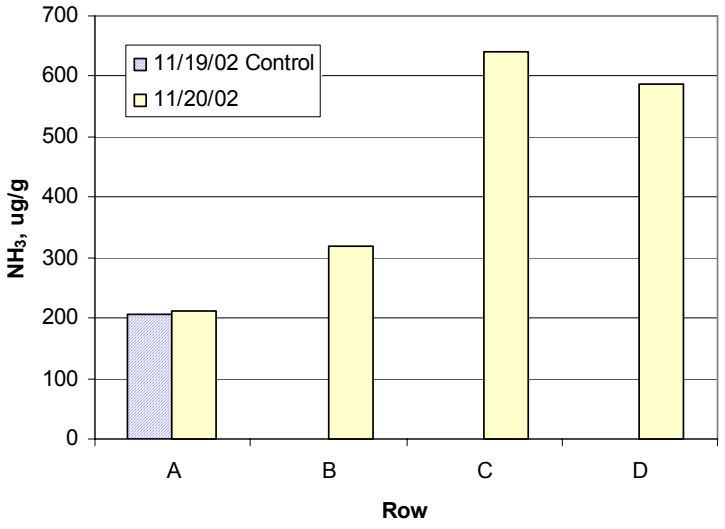


Figure 18. Ammonia content of ash as a function of row in the ESP.

Special analyses were carried out on the A Row ash sample. The content of four other metals was analyzed and standard leaching analyses for mercury were carried out (Table 6).

To date, very few power plant ash samples have had any measurable mercury leaching during the procedures. For the Salem Harbor sample, the leaching results show a detectable amount of mercury for only two out of eight samples. The ash samples containing PAC do not seem different than the control sample in terms of leaching. However, since most of the leaching results are below the detection limit, it is impossible to conclude with any certainty if the control sample is truly different from the sorbent-containing samples. The amount of mercury that is leached is still far below the EPA limit for Hg from TCLP analysis of solids.

Cd and Pb contents of the ash do not change much with addition of the PAC (Figure 19). However, the Se content of the ash increases by about a factor of three in the samples containing PAC. This is consistent with the results from Brayton Point. The As content of the long-term ash is very low as compared to the control and baseline samples

Table 6. Ash Metals and Leaching Analyses for Ash Samples from A Row.

ADA ES ID	MTI ID	Date	Ash Sample	As, µg/g	Cd, µg/g	Pb, µg/g	Se, µg/g	Hg, mg/L	
								TCLP	SGLP
SH00185	03-020	11/19/02	Control	12	0.97	23.2	14	0.034	<0.01
SH00070	02-193	9/24/02	Baseline	31	2.5	34	50	<0.01	0.016
SH00195	03-026	11/20/02	Long-term	0.08	1.00	25.8	37.4	<0.01	<0.01
SH00223	03-033	11/22/02	Long-term	0.21	1.68	23	41	<0.01	<0.01

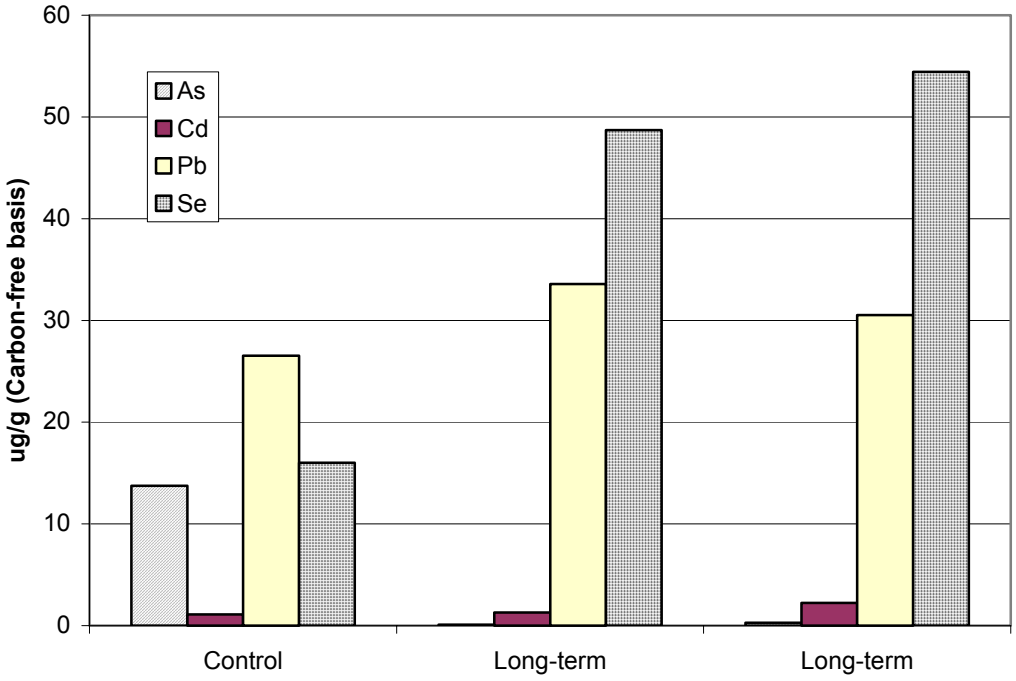


Figure 19. Metal content of ash, carbon-free basis.

APPENDIX:
Pore Size Distribution data for Salem Harbor Ash Samples

MTI ID	ADA ES ID	Date	Sample Location
03-020	SH00185	11/19/02	A-Row (control)
03-026	SH00195	11/20/02	A-Row
03-027	SH00198	11/20/02	B-Row
03-028	SH00201	11/20/02	C-Row
03-029	SH00203	11/20/02	D-Row

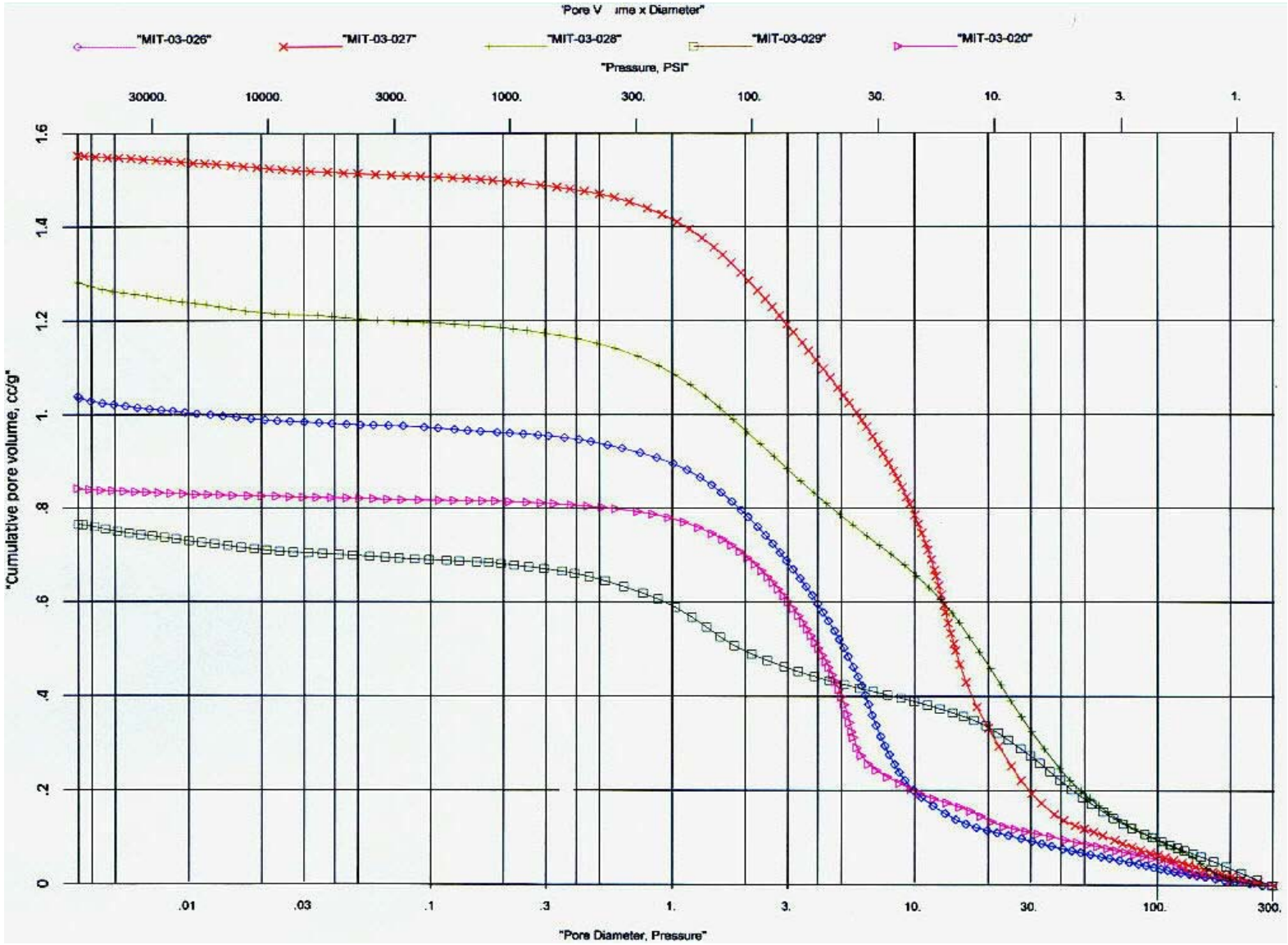
Pore size distribution by mercury porosimetry:

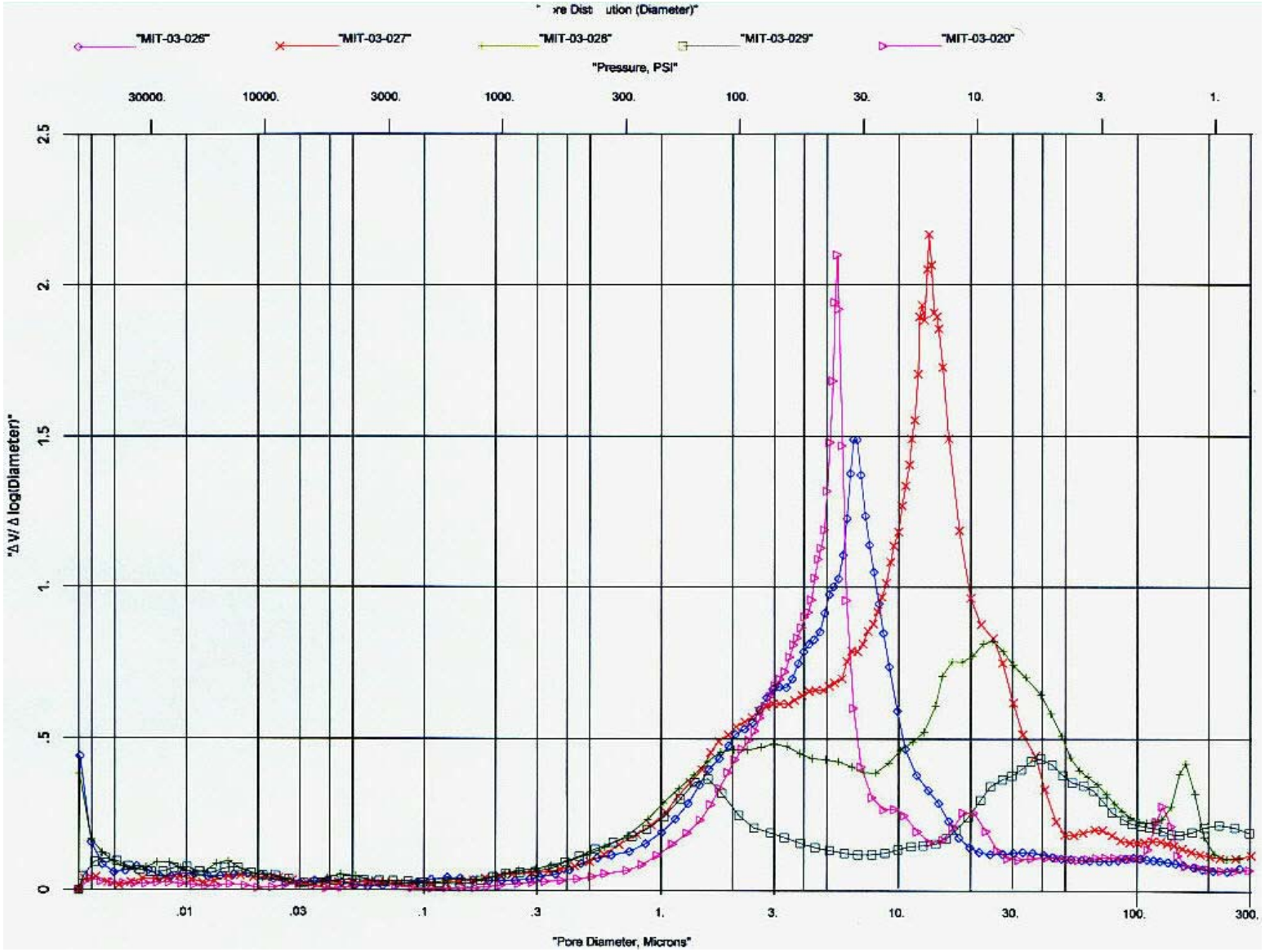
1. Pore volume versus diameter

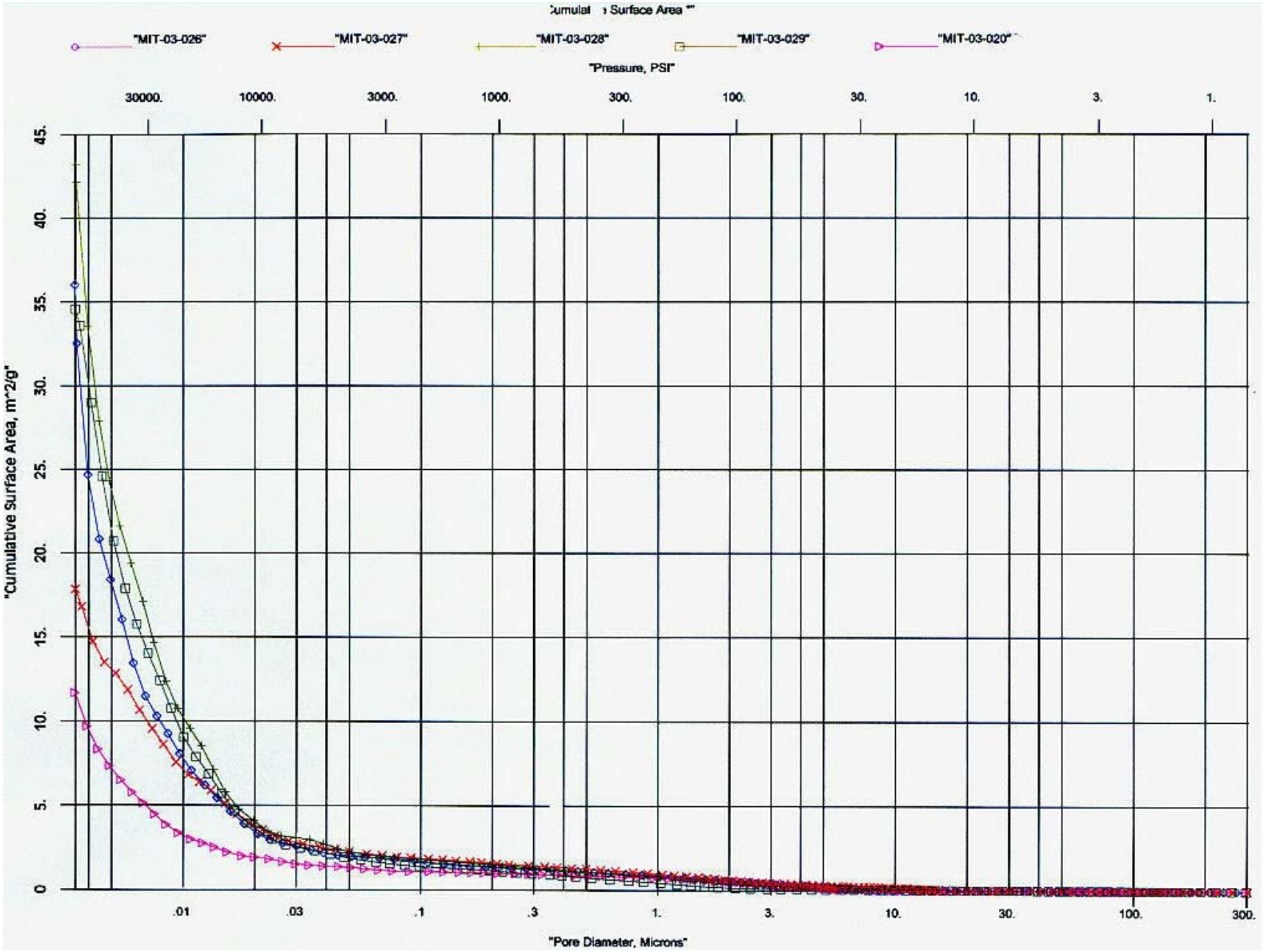
2. Pore distribution (diameter)

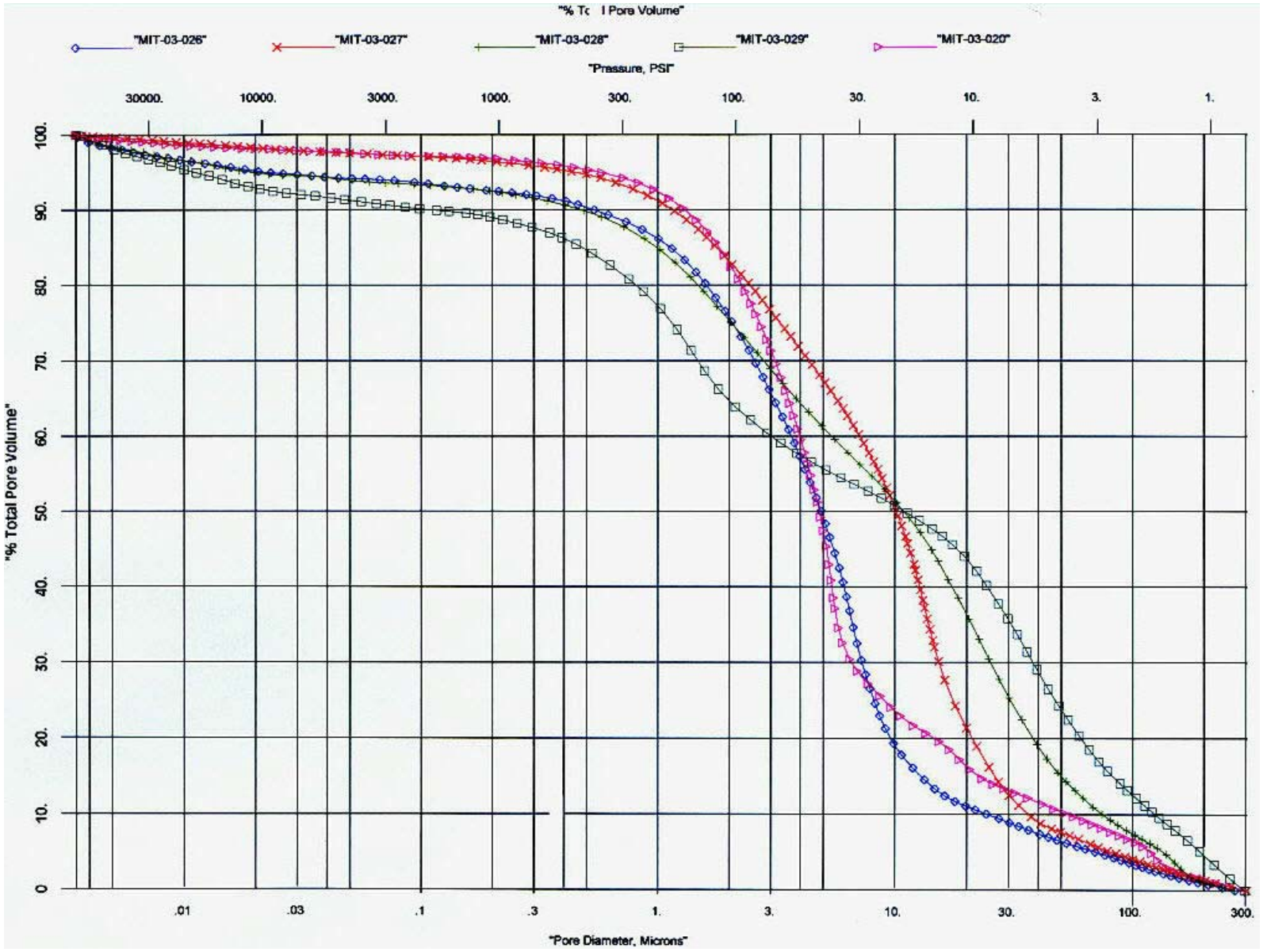
3. Cumulative surface area

4. Percent total pore volume


"Pore V ume x Diameter"
"MIT-03-026"
"MIT-03-027"
"MIT-03-028"
"MIT-03-029"
"MIT-03-020"
"Pressure, PSI"
30000.
10000.
3000.
1000.
300.
100.
30.
10.
3.
1.
"Cumulative pore volume, cc/g"
1.6
1.4
1.2
1.
.8
.6
.4
.2
0
.01
.03
.1
.3
1.
3.
10.
30.
100.
300.
"Pore Diameter, Pressure"


"MIT-03-026"
"MIT-03-027"
"MIT-03-028"
"MIT-03-029"
"MIT-03-020"
"Pressure, PSI"
30000.
10000.
3000.
1000.
300.
100.
30.
10.
3.
1.
"Δ V/ Δ log(Diameter)"
2.5
2.
1.5
1.
.5
0
.01
.03
.1
.3
1.
3.
10.
30.
100.
300.
"Pore Diameter, Microns"


"MIT-03-026"
"MIT-03-027"
"MIT-03-028"
"MIT-03-029"
"MIT-03-020"
"Pressure, PSI"
30000.
10000.
3000.
1000.
300.
100.
30.
10.
3.
1.
"Cumulative Surface Area, m^2/g"
0
5.
10.
15.
20.
25.
30.
35.
40.
45.
.01
.03
.1
.3
1.
3.
10.
30.
100.
300.
"Pore Diameter, Microns"


"% Total Pore Volume"
"MIT-03-026"
"MIT-03-027"
"MIT-03-028"
"MIT-03-029"
"MIT-03-020"
"Pressure, PSI"
30000.
10000.
3000.
1000.
300.
100.
30.
10.
3.
1.
"% Total Pore Volume"
100.
90.
80.
70.
60.
50.
40.
30.
20.
10.
0
.01
.03
.1
.3
1.
3.
10.
30.
100.
300.
"Pore Diameter, Microns"

APPENDIX G

ECONOMIC ANALYSIS

Capital Costs

Decription	Units	Value	Notes
ACI Storage and Injection System	$	$370,000	
Piping, Manifolds & Lances	$	$25,000	
Foundations and Steel (installed)	$	$55,000	
Electrical Supply Upgrades	$	$25,000	
Misc Utilities, Lighting		$20,000	
Controls Integration	$	$20,000	
Subtotal		$515,000	
Taxes	$	$30,900	
Freight	$	*incl*	
Purchased Equipment Cost Subtotal	$	$545,900	
Installation of Process Equipment	$	$130,000	
Total Direct Cost	$	**$675,900**	
Indirects			
General Facilities	10%	$67,590	
Engineering Fees	10%	$67,590	
Project Contingency	15%	$101,385	
Process Contingency	5%	$33,795	
Total Plant Cost (TPC)	$	**$946,260**	
Allow. for Funds During Constr. (AFDC)	$	$0	Construction period < 1yr.
Total Plant Investment (TPI)	$	$946,260	
Preproduction Costs	$	$0	
Inventory Capital	$	$0	
Total Capital Requirement (TCR)	$	**$946,260**	
	$/kW	$11.27	

Variable O&M and Costs

Cost Basis (Year)		2003	
Sorbent Costs		$569,400	
Waste Disposal Costs		$0	
Power Consumption	kW	25	
Power Cost ($0.05/kW)		$7,118	
Operating Labor (4 hours/day, $45/hr))		$65,700	May need higher labor rates for Boston
Maintenance Costs		$19,750	
Periodic Replacement Items		$10,000	
Total	$	**$671,968**	
$/kW	$/kW	$8.00	
mills/kWhr	mills/kW-hr	$1.40	

Economic Factors			
Net Generating Capacity	MW	84	
Annual Capacity Factor	%	65%	
Power costs	$/kw	$0.05	
Operating Labor Rate	$/hr	$45	
Cost Basis - Year Dollars	Year	2003	
Capital Esc During Construction	%	1.5%	
Construction Years		0.5	
Annual Inflation	%	2.5%	
Discount Rate, % (MAR) =	%	9.2%	
AFUDC Rate	%	10.8%	
First Year Fixed Charge Rate, Current$	%	22.3%	
First Year Fixed Charge Rate, Const$	%	15.7%	
Lev Fixed Charge Rate, Current$ (FCR) =	%	16.9%	
Lev Fixed Charge Rate, Const$ (FCR) =	%	11.7%	
Service Life (years) =	Years	20	
Escalation Rates :			
Consumables (O & M) =	%	3.0%	
Fuel =	%	5.0%	
Power =	%	3.0%	
		Current$ Basis	Constant $ Basis
P/A Factor		9.00	11.45
A/P Factor		0.11	0.09
P/AE Factors			
'Consumables (O&M)		11.45	11.45
'Power		11.45	11.45
Levelizing Factors			
'Consumables (O&M)		1.27	1.00
'Power		1.27	1.00
First Year Costs		Current$ Basis	Constant $ Basis
Fixed Costs		$148,563	$148,563
Variable O&M		$671,968	$671,968
Total First Year Costs	**$**	**$820,530**	**$820,530**
$/kw	**$/kW**	**$9.77**	**$9.77**
	mills/kW-hr	**$1.72**	**$1.72**
20 yr Annual Levelized Costs		Current $ Basis	Constant $ Basis
Fixed Costs		$110,712	$110,712
Operating Costs			
'Reagent		$724,528	$569,400
'Waste Disposal		$0	$0
'Power		$9,057	$7,118
'Labor		$83,599	$65,700
'Maint		$25,131	$19,750
'Spare Parts		$12,724	$10,000
Total Annual 20 yr Levelized Costs	**$/year**	**$965,751**	**$782,680**
$/kW	**$/kW**	**$11.50**	**$9.32**
	mills/kW-hr	**$2.02**	**$1.64**