

FULL-SCALE TESTING OF ENHANCED MERCURY CONTROL TECHNOLOGIES FOR WET FGD SYSTEMS

Final Report

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TABLE OF CONTENTS

<u>Section</u>		<u>Page</u>
ABSTRACT/REPORT SUMMARY		
1.0	EXECUTIVE SUMMARY	10
1.1	Approach.....	10
1.2	Ontario Hydro Flue Gas Sampling Results Summary	12
1.3	Mercury in Coal Utilization By-Products Results Summary.....	14
1.4	Market Impact.....	15
1.5	Comparison with Competing Technologies.....	17
2.0	INTRODUCTION.....	21
2.1	Background and Objectives	21
2.2	Benefits of the B&W/MTI Enhanced Wet FGD Mercury Removal Process	21
2.3	Project Sponsors.....	22
3.0	TECHNICAL DISCUSSION	23
3.1	Process Description.....	23
3.2	Technical Approach.....	23
3.2.1	Overview	23
3.2.2	Field Operation Phases	26
3.2.3	Mobile Test Pump Skid	27
3.2.4	Ontario Hydro Measurements – General Methodology.....	30
3.2.5	PS Analytical Mercury Analyzer System	32
3.3	Ontario Hydro Flue Gas Sampling Results.....	36
3.3.1	MSCPA, Endicott Station	36
3.3.1.1	MSCPA Test Plan	36
3.3.1.2	Plant Operation.....	39
3.3.1.3	Parametric Test Results	41
3.3.1.4	Performance Verification Test Results.....	44
3.3.1.5	Long-Term Operation.....	48
3.3.2	Cinergy, Zimmer Station	52
3.3.2.1	Test Plan	52
3.3.2.2	Plant Operation.....	53
3.3.2.3	Performance Verification Results	55
3.3.3	Ontario Hydro Flue Gas Sampling Summary and Conclusions	59
3.4	A Case for Oxidation Technologies.....	60
3.5	Mercury in Coal Utilization By-Products (CUBs).....	66
3.5.1	Conventional Chemical Analyses	66
3.5.1.1	Endicott Stream Sampling.....	67
3.5.1.2	Zimmer Stream Sampling	75
3.5.1.3	Results of Conventional Chemical Analyses	84
3.5.1.4	Coal Analyses.....	88

TABLE OF CONTENTS (Cont'd)

<u>Section</u>		<u>Page</u>
3.5.2	Thermal Dissociation Tests.....	92
3.5.2.1	Apparatus and Method	93
3.5.2.2	Preparation and Testing of Standards.....	97
3.5.2.3	TDT Tests of Endicott and Zimmer Samples.....	105
3.5.2.4	TDT vs. Conventional Chemistry	112
3.5.3	Mercury Tracking	116
3.5.4	CUBs Results and Conclusions	119
3.6	Quality Assurance/Quality Control.....	121
3.7	Technical Conclusions	123
3.7.1	Ontario Hydro Flue Gas Sampling Conclusions.....	123
3.7.2	Mercury in Coal Utilization By-Products Conclusions	124
4.0	MARKETING/COMMERCIALIZATION DISCUSSION	126
4.1	Market Application	126
4.2	By-Product Market.....	133
4.3	Marketplace Acceptance	134
4.4	Increased Use of Ohio Coal.....	136
4.5	Process Economics.....	136
4.6	Commercialization Plan.....	137
5.0	REFERENCES	139
APPENDIX A – PROXIMATE ANALYSES FOR ZIMMER COAL SAMPLES		A-1
APPENDIX B – PLANT DATA ACQUISITION SYSTEM DATA		B-1

LIST OF TABLES

<u>Table</u>		<u>Page</u>
1.1-1	Test Location Characteristics Comparison.....	11
1.3-1	Average Mercury Concentration for Major Process Streams.....	15
1.4-1	U.S. Coal-fired Generating Market Summary.....	17
1.5-1	Costs of Mercury Removal Processes	19
1.5-2	Comparison of WFGD + E-Hg vs. ACI + SDA.....	20
1.5-3	Comparison of WFGD + E-Hg vs. ACI	20
3.2-1	Test Location Characteristics Comparison.....	23
3.2-2	Flue Gas Sampling Details	31
3.2-3	PS Analytical Mercury Analyzer Specifications	33
3.3-1	Summary of Parametric Tests – Endicott.....	37
3.3-2	Summary of Plant Operating Conditions – Endicott	40

LIST OF TABLES (Cont'd)

<u>Table</u>		<u>Page</u>
3.3-3	Summary of Hg Speciation Results – Endicott Verification Tests	46
3.3-4	Summary of Hg Speciation Results – Endicott Long Term Tests.....	50
3.3-5	Summary of Plant Operating Conditions – Zimmer.....	54
3.3-6	Summary of Hg Speciation Results – Zimmer Verification Tests	56
3.4-1	Chloride Addition Test Conditions	63
3.5-1	Process Stream Sample Preparation Techniques for Mercury Analysis	66
3.5-2	Process Stream Analytical Methods.....	67
3.5-3	Samples Collected and Analyzed from Endicott.....	82
3.5-4	Samples Collected and Analyzed from Zimmer	83
3.5-5	Results of Mercury Analyses on CUB Samples from Endicott	84
3.5-6	Results of Mercury Analyses on CUB Samples from Zimmer	85
3.5-7	Endicott Ultimate Coal Analyses, Cl and Hg.....	89
3.5-8	Endicott Coal: Cl, Hg	90
3.5-9	Zimmer Ultimate Coal Analyses, Cl and Hg.....	90
3.6-1	Analytical Quality Control Checks for Trace Metal Analysis	123
4.1-1	U.S. Coal-fired Utility Industry Scrubbed and Unscrubbed Markets	126
4.1-2	U.S. Coal-fired Generating Market Summary.....	128
4.1-3	Impact of Elemental Hg Oxidation.....	129
4.1-4	Costs of Mercury Removal Processes	131
4.1-5	Comparison of WFGD + E-Hg vs. ACI + SDA.....	132
4.1-6	Comparison of WFGD + E-Hg vs. ACI	133
4.4-1	Current Status of Ohio Coal Use and Ohio Generating Capacity	136
4.5-1	Summary of Costs for 500 MW E-Hg Process	137

LIST OF FIGURES

<u>Figure</u>		<u>Page</u>
1.2-1	Summary of Hg Speciation Results - Endicott Verification Tests.....	12
1.2-2	Summary of Hg Speciation Results - Endicott Long Term Tests	13
1.2-3	Effect of Reagent Feed Rate on outlet Hg Concentration - Endicott	13
1.2-4	Summary of Hg Speciation Results – Zimmer Verification Tests	14
3.2-1	MSCPA Endicott Station, Litchfield, Michigan	24
3.2-2	Cinergy's Zimmer Station, Moscow, Ohio	25
3.2-3	Project Schedule	26
3.2-4	Reagent Injection Skid	27
3.2-5	Reagent Injection Skid Equipment Schematic	29
3.2-6	Laboratory Trailer (Exterior).....	31
3.2-7	Laboratory Trailer (Interior).....	32
3.2-8	PS Analytical Mercury Analyzer Schematic	33
3.2-9	PS Analytical Mercury Analyzer	34
3.3-1	WFGD Inlet Sampling Location – Endicott.....	38
3.3-2	WFGD Outlet (Stack) Sampling Location – Endicott.....	38

LIST OF FIGURES (Cont'd)

<u>Figure</u>		<u>Page</u>
3.3-3	Hg Speciation Summary, Parametric Tests 1 – 4	41
3.3-4	Hg Speciation Summary, Parametric Tests 5 – 8	42
3.3-5	Summary of WFGD Outlet Hg Speciation, Parametric Tests	43
3.3-6	Effect of Reagent Feed Rate on Outlet Hg Concentration – Endicott	44
3.3-7	Summary of Hg Speciation Results - Endicott Verification Tests	45
3.3-8	Outlet Oxidized and Elemental Hg Concentration vs. Inlet Oxidized Hg Concentration	47
3.3-9	Outlet vs. Inlet Elemental Hg, Verification Tests – Endicott	48
3.3-10	Summary of Hg Speciation Results - Endicott Long Term Tests	49
3.3-11	Outlet vs. Inlet Elemental Hg, Verification and Long Term Tests – Endicott	51
3.3-12	WFGD Inlet Sampling Location – Zimmer	52
3.3-13	WFGD Outlet Sampling – Zimmer	55
3.3-14	Summary of Hg Speciation Results – Zimmer Verification Tests	53
3.3-15	Outlet Elemental Mercury Concentration as a Function of Inlet Elemental Mercury Concentration – Pilot, Endicott, and Zimmer	58
3.3-16	Speciated Mercury Removal Performance, Baseline and w/ Reagent	59
3.4-1	Mercury Speciation for Typical Ohio Coals	61
3.4-2	Range of Chlorine Content for Typical Ohio Coals	61
3.4-3	Comparison of Mercury Control Scenarios	62
3.4-4	Impact of Chloride Addition on Mercury Speciation	64
3.4-5	Effect of SCR Catalyst on Mercury Speciation	65
3.5-1	Endicott Coal Sampling Device and Pulverizer Feeder Sampling Port	69
3.5-2	Mercury Removal Reagent Tanker at Endicott	69
3.5-3	ESP Hoppers at Endicott	70
3.5-4	ESP Ash Sampling at Endicott	70
3.5-5	Pug Mill on the Waste Ash Silo at Endicott	71
3.5-6	Limestone Slurry Pump and Storage Tank at Endicott	71
3.5-7	Settled Sludge in a Tank in the Water Treatment Process at Endicott	72
3.5-8	Sample Point for the Water Treatment Sludge at Endicott	72
3.5-9	Treated Water Overflow Weir at Endicott	73
3.5-10	WFGD Slurry Sample Tap on the Absorber Recirculating Tank at Endicott	73
3.5-11	Gypsum Filter Drum at Endicott	74
3.5-12	Gypsum Filter Pile at Endicott	74
3.5-13	Thiosorbic Lime Slurry flowing from Storage Tanks at Zimmer	77
3.5-14	Reclaim Water Sampling in the Scrubber Building at Zimmer	77
3.5-15	ESP Hopper Layout at Zimmer	78
3.5-16	ESP Ash Sampling at Zimmer	78
3.5-17	Ash from the South Ash Silo being Loaded into a Tanker at Zimmer	79
3.5-18	WFGD Slurry Sampling at Zimmer	79
3.5-19	WFGD Slurry Fines from the Centrifuges at Zimmer	80
3.5-20	Centrate Water from the Centrifuges at Zimmer	80

3.5-21	Gypsum Pile (left, white) and Centrifuges (center, blue) at Zimmer.....	81
3.5-22	Mercury vs. ESP Field for Endicott and Zimmer.....	87
3.5-23	Mercury in Gypsum and WFGD Slurry Solids for Endicott and Zimmer	87
3.5-24	Mercury in WFGD CUB for Zimmer.....	88
3.5-25	Cl and Hg in Endicott Coal Samples.....	91
3.5-26	Cl and Hg in Zimmer Coal Samples	91
3.5-27	Vapor Pressure of Hg^0 and Select Hg Salts.....	92
3.5-28	Thermal Dissociation Test Apparatus	93
3.5-29	TDT Heated Hose, Pyrolyzer, Control Oven, Argon Flow Meters.....	94
3.5-30	TDT Data Acquisition System	94
3.5-31	TDT, Inserting a Sample Boat into the Control Oven.....	95
3.5-32	PSA Mercury Analyzer and Preconditioner.....	95
3.5-33	Hg^0 Impinger	96
3.5-34	Fines in Endicott WFGD Slurry	97
3.5-35	Example TDC.....	99
3.5-36	Blank Sample Boat.....	100
3.5-37	Multiple TDC for the $HgSO_4$ Standard at Various Sample Weights	100
3.5-38	TDC for the HgO Standard Year 2000.....	101
3.5-39	TDC for the HgO Standard Year 2002.....	101
3.5-40	TDC for the HgS Standard Year 2000	102
3.5-41	TDC for the HgS Standard Year 2002	102
3.5-42	TDC for the $HgSO_4$ Standard in 2000.....	103
3.5-43	TDC for the $HgSO_4$ Standard in 2002.....	103
3.5-44	TDC for the $HgCl_2$ Standard in 2000	104
3.5-45	TDC for the $HgCl_2$ Standard in 2002	104
3.5-46	TDC for Endicott Gypsum	106
3.5-47	TDC for Zimmer Gypsum.....	107
3.5-48	TDC for Endicott ESP Ash by Field	107
3.5-49	TDC for Endicott Waste Ash	108
3.5-50	TDC for Endicott WFGD Slurry	108
3.5-51	TDC for Zimmer WFGD Slurry.....	109
3.5-52	TDC for Endicott WFGD Slurry Fines	110
3.5-53	TDC for Zimmer WFGD Slurry Fines	111
3.5-54	TDC for Endicott Water Treatment Sludge	111
3.5-55	TDT vs. Conventional Chemistry for ESP and Waste Ash.....	113
3.5-56	TDT vs. Conventional Chemistry for WFGD Slurry and Gypsum.....	114
3.5-57	TDT vs. Conventional Chemistry for WFGD Slurry Fines	115
3.5-58	Hg Flow Schematic for Endicott.....	117
3.5-59	Hg Flow Schematic for Zimmer.....	118
4.1-1	Wet Scrubber Market by Reagent Type	126

ABSTRACT/REPORT SUMMARY

Wet flue gas desulfurization (wet FGD) systems are currently installed on about 25% of the coal-fired utility generating capacity in the U.S., representing about 15% of the number of coal-fired units. Depending on the effect of operating parameters such as mercury content of the coal, form of mercury (elemental or oxidized) in the flue gas, scrubber spray tower configuration, liquid-to-gas ratio, and slurry chemistry, FGD systems can provide cost-effective, near-term mercury emissions control options with a proven history of commercial operation. For boilers already equipped with FGD systems, the incremental cost of any vapor phase mercury removal achieved is minimal. To be widely accepted and implemented, technical approaches that improve mercury removal performance for wet FGD systems should also have low incremental costs and have little or no impact on operation and SO₂ removal performance.

The ultimate goal of the ***Full-scale Testing of Enhanced Mercury Control for Wet FGD Systems Program*** was to commercialize methods for the control of mercury in coal-fired electric utility systems equipped with wet flue gas desulfurization (wet FGD). The program was funded by the U.S. Department of Energy's National Energy Technology Laboratory, the Ohio Coal Development Office within the Ohio Department of Development, and Babcock & Wilcox. Host sites and associated support were provided by Michigan South Central Power Agency (MSCPA) and Cinergy.

Field-testing was completed at two commercial coal-fired utilities with wet FGD systems: 1) MSCPA's 55 MW_e Endicott Station and 2) Cinergy's 1300 MW_e Zimmer Station. Testing was conducted at these two locations because of the large differences in size and wet scrubber chemistry. Endicott employs a limestone, forced oxidation (LSFO) wet FGD system, whereas Zimmer uses Thiosorbic® Lime (magnesium enhanced lime) and *ex situ* oxidation. Both locations burn Ohio bituminous coal.

Endicott Station. Average mercury removal across the wet FGD system during the Verification and Long-Term tests ranged from 76% to 79%. Most of the oxidized mercury present in the flue gas was removed in the wet FGD system; no increase in elemental mercury concentration was observed during the Endicott testing, indicating that the control technology was successful in not only maintaining high oxidized mercury removal but simultaneously suppressing mercury reemission.

Zimmer Station. Following the Endicott test program, two weeks of Verification tests were performed at Cinergy's Zimmer station. Average mercury removal across the wet FGD system during these tests averaged 51%. Compared to the Endicott results, lower oxidized mercury removal performance was observed at Zimmer (87% vs. 96%). In addition, elemental mercury concentrations increased across the wet FGD system, indicating that the control technology was not effective in suppressing the reemission of captured mercury from the scrubber. Testing conducted with 50% more reagent feed at the end of the Zimmer test program showed no improvement in mercury removal performance.

At both power plants, the wet FGD systems were very effective in removing oxidized mercury from the flue gas entering the scrubber. Total wet FGD mercury removal performance, however, was limited by the amount of elemental mercury present in the inlet flue gas. A comparison of various technical scenarios illustrated the importance of a viable mercury oxidation technology in obtaining high total wet FGD mercury removals. In one example (75% oxidized, 25% elemental entering a wet FGD system), combining a viable oxidation technology with B&W/MTI's control technology could improve mercury removal to 91%; by comparison, either technology by itself yielded a maximum removal of 78%.

1.0 EXECUTIVE SUMMARY

A wide range of mercury emissions control performance for wet scrubbers in coal applications appear in the literature with a number of factors contributing to this variability. For example, significant differences in the mercury content of U.S. coals result in a wide range of mercury concentrations in the flue gas from the boiler. In addition, the form or species of mercury (elemental or oxidized) in the flue gas is thought to affect wet FGD system mercury removal efficiency. Mercury speciation in the flue gas is believed to be influenced by the type of coal fired, with sub-bituminous coals generating a higher relative proportion of elemental mercury than bituminous coals. Finally, the scrubber spray tower configuration, liquid-to-gas ratio, and slurry chemistry may also impact the reported mercury emissions control.

Wet FGD systems are currently installed on about 25% of the coal-fired utility generating capacity in the U.S., representing about 15% of the number of coal-fired units. Depending on the effect of the operating parameters mentioned above, FGD systems can provide cost-effective, near-term mercury emissions control options with a proven history of commercial operation. For boilers already equipped with FGD systems, the incremental cost of any vapor phase mercury removal achieved is minimal. To be widely accepted and implemented, technical approaches that improve mercury removal performance for wet FGD systems should also have low incremental costs and have little or no impact on operation and SO₂ removal performance.

The ultimate goal of the ***Full-scale Testing of Enhanced Mercury Control for Wet FGD Systems Program*** was to commercialize methods for the control of mercury in coal-fired electric utility systems equipped with wet flue gas desulfurization (wet FGD). The two specific objectives of the project were 1) ninety percent (90%) overall system mercury removal and 2) costs below ¼ to ½ of today's competing activated carbon mercury removal technologies.

The program was funded by the U.S. Department of Energy's National Energy Technology Laboratory, the Ohio Coal Development Office within the Ohio Department of Development, and Babcock & Wilcox. Host sites and associated support were provided by Michigan South Central Power Agency (MSCPA) and Cinergy.

1.1 APPROACH

Field-testing was completed at two commercial coal-fired utilities with wet FGD systems: 1) MSCPA's 55 MW_e Endicott Station and 2) Cinergy's 1300 MW_e Zimmer Station. Testing was conducted at these two locations because of the large differences in size and wet scrubber chemistry. Endicott employs a limestone, forced oxidation (LSFO) wet FGD system, whereas Zimmer uses Thiosorbic® Lime (magnesium enhanced lime) and *ex situ* oxidation. Both locations burn Ohio high-sulfur bituminous coal. Table 1.1-1 compares the characteristics of the two test locations.

Table 1.1-1: Test Location Characteristics Comparison

	MSCPA Endicott Station	Cinergy Zimmer Station
Electricity Generation	55 MW _e	1300 MW _e
Number of Wet Scrubber Modules	1	6
Wet Scrubber Reagent	Limestone	Thiosorbic® Lime
Wet Scrubber Oxidation Method	<i>In situ</i> Forced Oxidation	<i>Ex situ</i> Forced Oxidation
Wet Scrubber Liquid-to-gas Ratio	78 gal/1000 acf	21 gal/1000 acf
Slurry pH	5.4 – 5.6	5.8 – 6.0
Inlet SO₂ Concentration	3600 ppm	3300 ppm
Gypsum Use	Cement	Wallboard

Field operation began at the Endicott Station. The phases of operation at the Endicott Station were as follows:

- Parametric testing to define the optimal operating parameters for the process.
- Two weeks of verification testing to verify the performance of the process with the selected operating conditions.
- Four months of long-term operation to continue the verification of the amount of mercury removal achieved and to prove that there were no long-term effects on SO₂ removal, materials of construction, or by-product utilization.

After completing field operation at the Endicott Station, the Babcock & Wilcox / McDermott Technology Inc. (B&W/MTI) enhanced mercury removal system was moved to the Zimmer Station for testing. Field operation at the Zimmer Station included:

- Two weeks of verification testing to verify the performance of the process with the selected operating conditions. Reagent was added to all operating wet scrubbers modules simultaneously.

To facilitate minimal construction and set-up at each plant site, a mobile equipment skid was fabricated to connect to the existing wet scrubber slurry systems. Ontario Hydro measurements were made to determine total mercury and mercury speciation. Sample train and equipment preparation and recovery took place in a fully equipped, mobile laboratory trailer. The specific sampling locations for the project were the wet scrubber inlet and wet scrubber outlet (or stack). A PSA Analytical on-line mercury analyzer was also used during testing.

1.2 ONTARIO HYDRO FLUE GAS SAMPLING RESULTS SUMMARY

Endicott Station. Average mercury removal across the wet FGD system during the Verification and Long-Term tests ranged from 76% (Figure 1.2-1) to 79% (Figure 1.2-2) respectively. Most of the oxidized mercury present in the flue gas was removed in the wet FGD system; no increase in elemental mercury concentration was observed during the Endicott testing, indicating that the control technology was successful in not only maintaining high oxidized mercury removal but simultaneously suppressing mercury reemission. A general trend of decreasing mercury concentration with increasing reagent feed rate was seen as shown in Figure 1.2-3.

Zimmer Station. Following the Endicott test program, two weeks of Verification tests were performed at Cinergy's Zimmer station. Average mercury removal across the wet FGD system during these tests averaged 51% (Figure 1.2-4). Compared to the Endicott results, lower oxidized mercury removal performance was observed at Zimmer (87% vs. 96%). In addition, elemental mercury concentrations increased across the wet FGD system, indicating that the control technology was not effective in suppressing the reemission of captured mercury from the scrubber. Testing conducted with 50% more reagent feed at the end of the Zimmer test program showed no improvement in mercury removal performance.

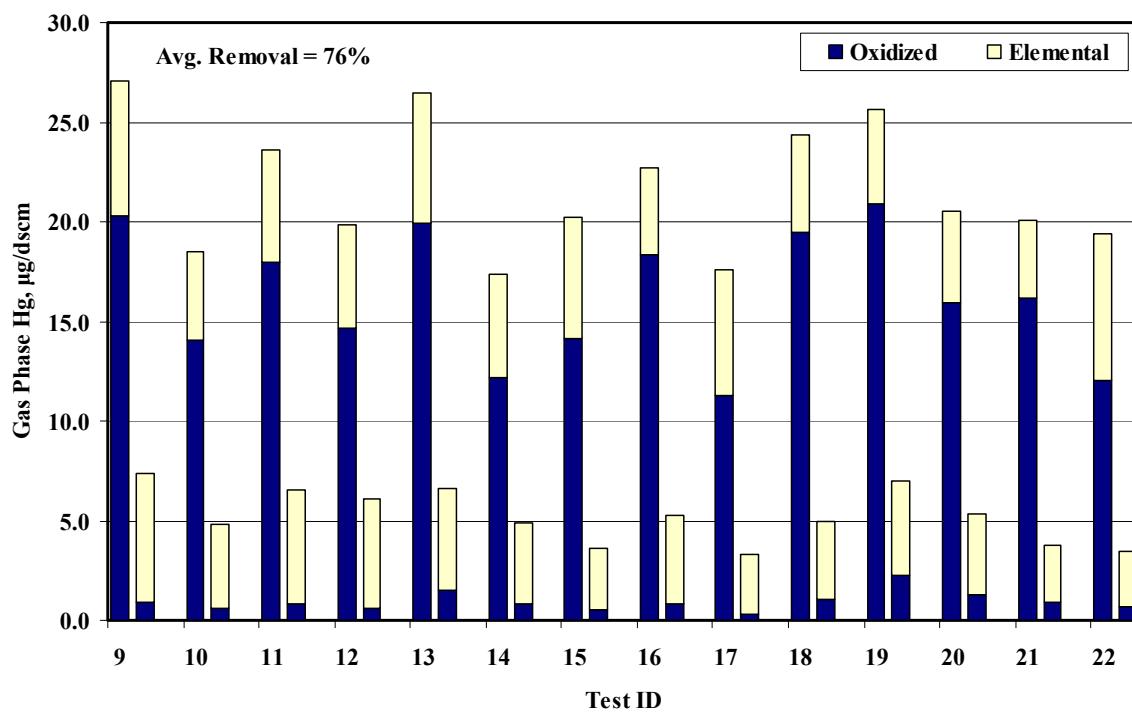


Figure 1.2-1: Summary of Hg Speciation Results – Endicott Verification Tests
(first bar of each test ID is inlet, second is outlet)

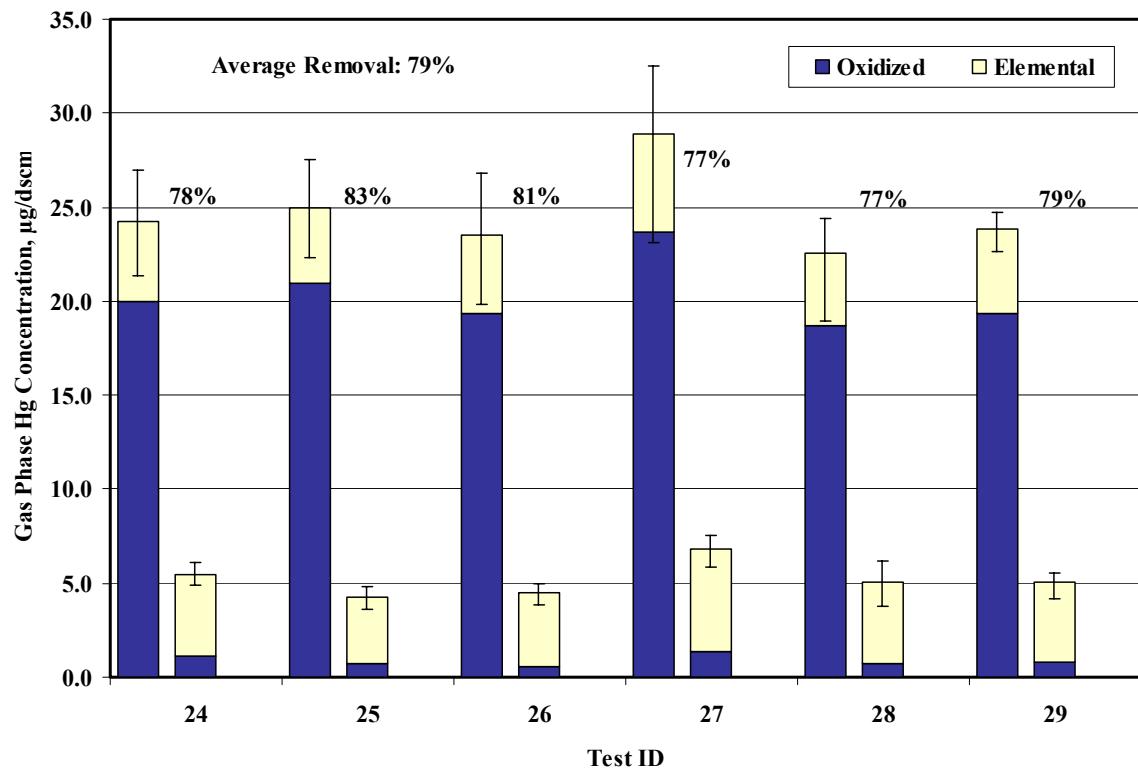


Figure 1.2-2: Summary of Hg Speciation Results – Endicott Long-Term Tests

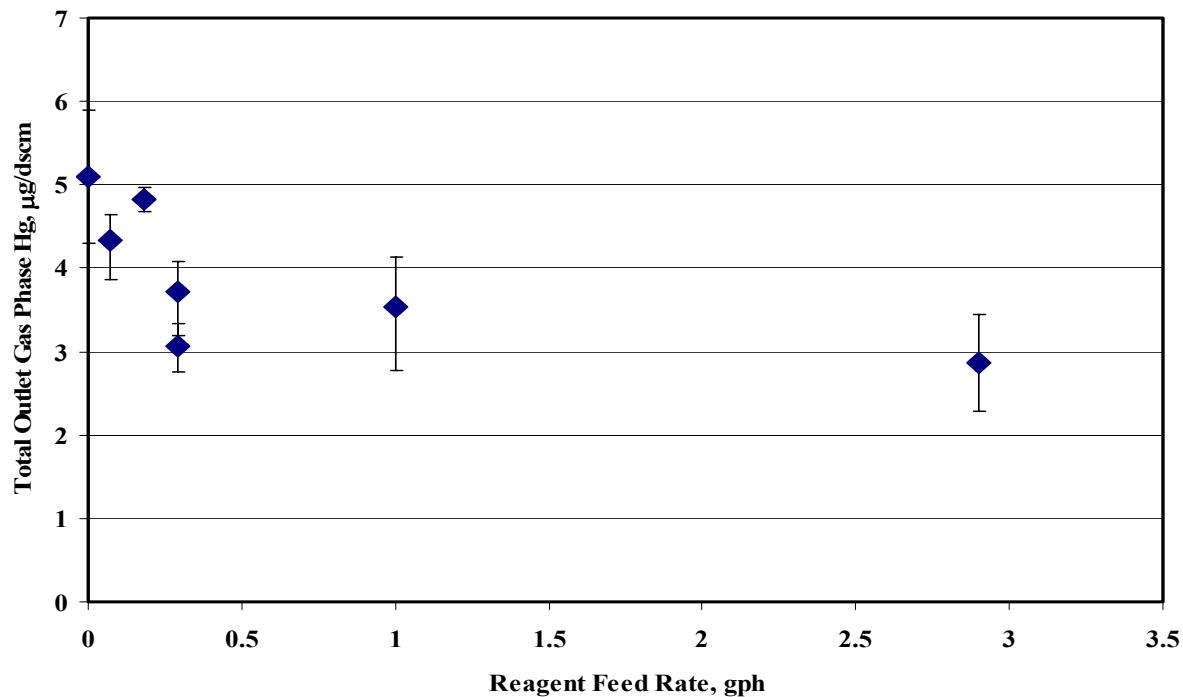


Figure 1.2-3: Effect of Reagent Feed Rate on Outlet Hg Concentration - Endicott

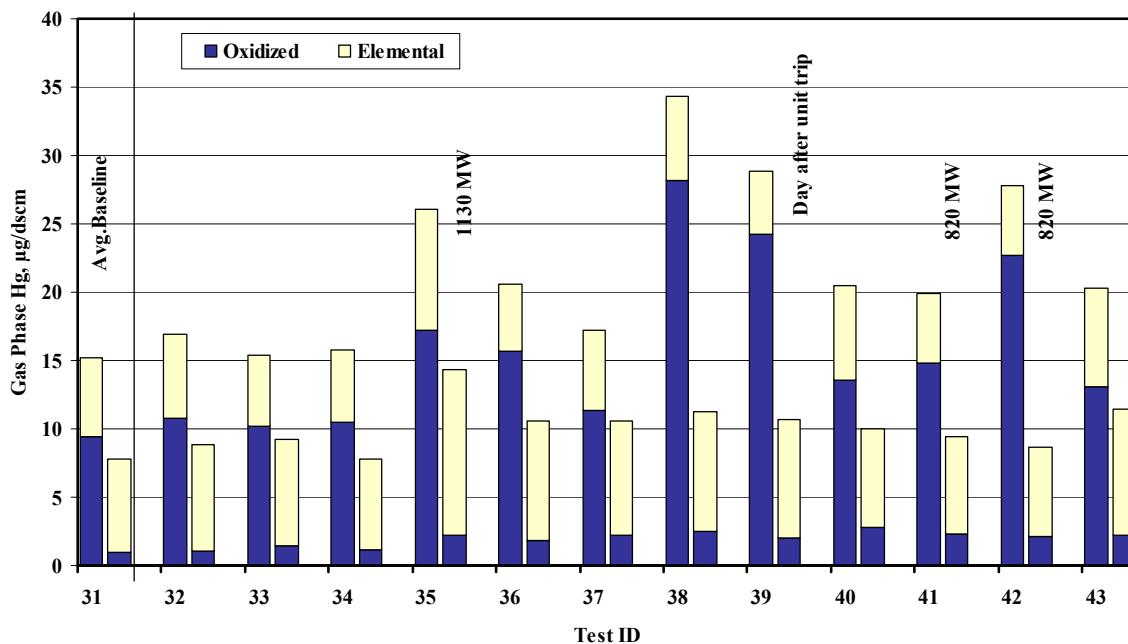


Figure 1.2-4: Summary of Hg Speciation Results – Zimmer Verification Tests

At both power plants, the wet FGD systems were very effective in removing oxidized mercury from the flue gas entering the scrubber. Total wet FGD mercury removal performance, however, was limited by the amount of elemental mercury present in the inlet flue gas. A comparison of various technical scenarios illustrated the importance of a viable mercury oxidation technology in obtaining high total wet FGD mercury removals. In one example (75% oxidized, 25% elemental entering a wet FGD system), combining a viable oxidation technology with B&W/MTI's control technology could improve mercury removal to 91%; by comparison, either technology by itself yielded a maximum removal of 78%.

1.3 MERCURY IN COAL UTILIZATION BY-PRODUCTS RESULTS SUMMARY

One of the most significant findings of the demonstration is that the mercury in the wet FGD Slurry was associated with the fines. This is significant because the two plants represent opposite ends of the spectrum in plant size and wet scrubber chemistry, and yet both exhibited this behavior, as did the MTI Pilot in previous studies¹. It is also important because the fines can be separated from the larger gypsum crystals, through the addition of a variety of commercially available equipment, to produce a gypsum product similar to natural gypsum as shown in the table below. The fines can be disposed of in standard landfills because the mercury has been shown to be stable. This finding also suggests that the mercury in wet FGD Coal Utilization By-products (CUB) is not bound to gypsum and may be forming a fine particulate of a pure compound or reacting with some component of the fines, like soot.

	<u>Natural Gypsum</u>	<u>Average FGD Gypsum</u>	<u>Zimmer (w/o fines)</u>	<u>Endicott (with fines)</u>
Minimum:	0.006 ppm (by wt)	0.03	0.03	0.48
Maximum:	0.05 ppm	1.32	0.10	1.15

From EPRI Technical Report² TR-103652

Table 1.3-1 shows the averaged mercury concentrations for the major process streams. The important differences include the low mercury content in the Zimmer ESP Ash and Gypsum. The low mercury in the ash may be due to the low amount of unburned carbon in the Zimmer Ash (1%) compared to Endicott Ash (9%). The gypsum has low mercury because the mercury containing fines are separated from the larger gypsum crystals as part of *ex situ* oxidation process. The fines are not separated at Endicott, so to obtain the value shown below, the fines were separated in the lab. The mercury (and chlorine) in the coal varied by about a factor of three over the course of the test at both sites.

Table 1.3-1: Average Mercury Concentration for Major Process Streams

Hg, ppm(dry)	Endicott	Zimmer
Coal	0.21	0.15
ESP Ash	0.32	0.016
Gypsum	0.70	0.055
Wet FGD Slurry	0.76	0.49
Wet FGD Slurry Fines	38 (by TDT)	13.3

The Thermal Dissociation Test (TDT) method was developed by MTI using the PSA Analytical mercury analyzer and appears to be a viable way of detecting small amounts of mercury in coal utilization by-products. The method produced distinct concentration vs. temperature curves for several pure mercury compounds that correlate well to vapor pressure data for these compounds. However, the curves for HgS and HgO overlap each other which make them indistinguishable. The area under the dissociation curve was shown to be directly proportional to the mercury concentration measured by conventional chemical analysis.

1.4 MARKET IMPACT

In Table 1.4-1, a summary of the current U.S. coal-fired utility market is shown. The market is arranged by geographic location, coal type, FGD type (if applicable), and particulate control device (PCD). The categorical breakdowns are based on EPA-supplied data available from their website. The six highlighted rows correspond to the six largest categories within the U.S. utility market and represent 85% of the total generating capacity. The various Hg removal impact scenario calculations in the following discussion are based only on these six categories.

Three Hg removal impact scenarios are shown in the table and represent the following:

- Current: The amount of mercury removal currently achieved for the various categories with existing pollution control equipment.
- Enhanced w/o Oxidation: The amount of mercury removal possible with the application of B&W/MTI's wet FGD control technology to units currently equipped with wet FGD systems (activated carbon injection (ACI) control is assumed for unscrubbed units).
- Enhanced w/ Oxidation: The amount of mercury removal possible with the application of the control technologies mentioned above *plus* the application of a technology capable of oxidizing 80% of the elemental mercury *present in the flue gas*. This technology would be applied upstream of any pollution control equipment or any mercury control technology.

For each of the three scenarios, a weighted removal average (and corresponding estimated emission rate) is calculated based on the installed generating capacity for each of the included categories. For example, the “Current” weighted removal average is 35% resulting in an estimated emission rate of 54 tons Hg/year, which agrees well with the generally reported rate of 50 to 55 tons Hg/year. The scenarios also assume that no fuel switching occurs.

The results presented in Table 1.4-1 illustrate several key considerations for improving Hg removal performance for coal-fired utilities:

- Two-thirds of the current U.S. generating capacity is supplied by ESP-equipped bituminous-fired and ESP-equipped sub-bituminous-fired units. Improved Hg control for these units will have a major impact on the nationwide emissions rate.
- Applying B&W/MTI's enhancement technologies to both scrubbed and unscrubbed units results in a 50% decrease in the emissions rate, from 54 tons/yr to 27 tons/yr.
- Combining B&W/MTI's control technologies with an oxidation technology capable of oxidizing 80% of the elemental Hg present in the flue gas results in a further reduction of 50%, down to 14 tons/yr. This reduction is due primarily to the conversion (and capture) of the significant amount of elemental mercury generated by the sub-bituminous-fired units.
- Even with the high levels of oxidized mercury generated in the oxidation-based scenario, ACI injection removes less Hg than wet scrubbing.

Table 1.4-1: U.S. Coal-fired Generating Market Summary

						Hg Removal Impact Scenarios		
Location	Coal Type	FGD Type	PCD Type	MW	% of Total MW	Current	Enhanced w/o Hg° Oxidation	Enhanced w/ Hg° Oxidation
Scrubbed Units								
East	Bit	Wet	ESP	39,345	12.8	63%	80%	92%
East	Bit	Wet	Other	3,496	1.1			
East	Bit	Dry	ESP	160	0.1			
East	Bit	Dry	Other	3,017	1.0			
East	Sub	Wet	ESP	1,954	0.6			
East	Sub	Wet	Other	44	0.0			
West	Bit	Wet	ESP	2,305	0.8			
West	Bit	Wet	Other	1,498	0.5			
West	Bit	Dry	Other	1,256	0.4			
West	Sub	Wet	ESP	13,412	4.4	57%	72%	91%
West	Sub	Wet	Other	9,867	3.2	57%	72%	91%
West	Sub	Dry	ESP	1,562	0.5			
West	Sub	Dry	Other	4,588	1.5			
West	Lig	Wet	ESP	8,726	2.8			
West	Lig	Dry	Other	1,380	0.4			
<i>Scrubbed Totals</i>				92,610				
<i>Unscrubbed Units</i>								
East	Bit	NA	ESP	109,659	35.7	18%	66%	79%
East	Bit	NA	Other	2,974	1.0			
East	Sub	NA	ESP	45,431	14.8	39%	63%	82%
East	Sub	NA	Other	1,807	0.6			
West	Bit	NA	ESP	2,438	0.8			
West	Bit	NA	Other	864	0.3			
West	Sub	NA	ESP	40,858	13.3	39%	63%	82%
West	Sub	NA	Other	6,795	2.2			
West	Lig	NA	ESP	1,031	0.3			
West	Lig	NA	Other	2,430	0.8			
<i>Unscrubbed Totals</i>				214,287		Weighted Averages		
	<i>U.S. Totals</i>			306,897		35%	68%	83%
						Estimated Emission Rates, ton/yr		
						53.8	26.9	14.2

1.5 COMPARISON WITH COMPETING TECHNOLOGIES

To date, the most extensive mercury control research has been related to mercury capture via sorbent injection (either alkali-based or carbon-based). Most of the pilot- and demonstration-scale test programs have focused on the use of activated carbon injection as the technology of choice for mercury control. This section compares the latest published mercury removal/cost information^{3,4,5} for ACI to B&W/MTI's enhanced wet FGD-based process for a variety of

scenarios. For the purposes of this discussion, the B&W/MTI process will be referred to as “E-Hg”. For all scenarios, particulate control is performed by an existing ESP.

For each scenario, annual leveledized costs (ALC) were calculated based on published removal/cost data for ACI and cost estimate modeling for E-Hg. The following operational assumptions were made when performing the cost calculations:

Size of Plant:	500 MW
Capacity Factor:	65%
Coal S:	3%, 1%, 0.3%
Coal Hg:	0.23 ppm
Cost of carbon:	\$0.425/lb
Carbon feedrate:	5000:1, 9000:1, 15,000:1 lb AC/lb Hg
Target Hg Removal:	80%
Base Wet FGD Hg Removal:	70%

Scenario 1: Existing Wet FGD + E-Hg vs. ACI

Intended to represent the most likely initial target base for E-Hg, the model plant is firing a 3% sulfur coal and is equipped with a wet FGD system. Table 1.5-1 summarizes the results of the analysis and provides the estimated capital, operating and maintenance (O&M) costs both for applying B&W/MTI’s enhancement process to an existing wet FGD system, and for installing a new wet FGD system with the enhancement process. Reagent cost is the majority of the O&M costs. The table also includes an equivalent evaluation using ACI technology solely for mercury capture at the 60 and 70 percent removal levels. Direct comparison of enhancement in an FGD system with ACI technology is difficult to establish given the fact that potential applications for each do not lend themselves to a direct comparison. Nevertheless, the incremental cost difference between the 60 and 70 percent removals with ACI may establish a better way to evaluate the relative cost benefit associated with improving mercury capture with the additive enhancement in a wet FGD system. Although it is highly unlikely that ACI would be used in a situation where the existing wet FGD system is already providing 70 percent removal, the 0.18 mil/kWh annual leveledized cost of improving this to 80 percent with the additive technology is substantially below the 0.80 mil/kWh cost differential between achieving 60 and 70 percent removal with ACI. This illustrates the fact that enhanced mercury capture on its own represents minimal additional expense for scrubber-equipped utilities interested in reducing their mercury emissions and assuring that the mercury captured will be retained within the system rather than being re-emitted in the elemental form.

While the values presented for ACI control are based on B&W/MTI’s own analysis of the cost of providing and operating an injection system, there are both positive and negative differences between the relative costs of capital and operating costs when compared to some of those reported by others. Because these differences are still being reconciled, no breakdown is provided on the capital and operating costs at this time. There is general agreement between the costs developed here and the \$2 – 5 million/yr range of overall annual leveledized costs being reported by those working more directly on ACI control technologies.^{3,4,5}

Table 1.5-1: Costs of Mercury Removal Processes

ENHANCED MERCURY CAPTURE IN A WET FGD SYSTEM	Existing 500 MW Installation	New 500 MW Installation
Total Capital Requirement, \$	3,000,000	63,000,000
Total System O&M Costs, \$/yr	125,000	3,200,000
Annual Levelized Cost, \$/yr	500,000	12,000,000
Annual Levelized Cost, mil/kWh	0.18	4.23
<hr/>		
MERCURY CAPTURE WITH ACI TECHNOLOGY	@ 60% Removal	@ 70% Removal
Annual Levelized Cost, \$/yr	2,400,000	4,700,000
Annual Levelized Cost, mil/kWh	0.85	1.65

The application of the B&W/MTI enhanced mercury capture process with a wet FGD system has the additional benefit of having virtually no impact on scrubber operation and gypsum quality. Moreover, it does not adversely affect the acceptability of fly ash for disposal/sale, a potential drawback ACI may have if it is not practical or economically attractive to separate by-product fly ash from the spent activated carbon. This aspect came to light in the demonstration of ACI at Wisconsin Electric's Pleasant Prairie Power Plant where the carbon prevented its use as a cement admixture. The economic impact in this case was estimated to be \$12 to \$15 million/yr due to lost fly ash sale revenue and increased landfill disposal costs.⁴

Scenario 2: New Wet FGD + E-Hg vs. ACI + Spray Dryer Absorber (SDA)

As further reductions in U.S. SO₂ emissions become more likely to be enacted, the installation of additional FGD capacity becomes more likely. In effect, the 'threshold' coal sulfur level, above which some type of FGD system would be required, would continue to decrease. As a result, new FGD systems would, in more and more cases, become financially attractive as the amount of low-sulfur coal would continue to decrease and demand increase. In some instances, especially for units already firing lower sulfur coal, spray dryer absorbers (SDA) tend to be favored over wet FGD systems. If mercury control legislation is enacted in conjunction with more stringent SO₂ emissions requirements, however, the choice of equipment becomes more interesting. This scenario represents a potentially significant portion of the current U.S. generating market. For example, focusing solely on unscrubbed, ESP-equipped units east of the Mississippi firing bituminous coals encompasses 109,000 MW, one-third of the current generating capacity in the U.S.

In this scenario, a 1% sulfur coal is being fired in the 500 MW model plant. For the ACI + SDA options, it has been assumed that the addition of the SDA system will result in Hg removal performance comparable to wet FGD. In Table 1.5-2, the ALC (expressed in mil/kWh and \$/yr) are shown for this comparison.

Table 1.5-2: Comparison of Wet FGD + E-Hg vs. ACI + SDA

ALC	Wet FGD @ 70%	Wet FGD + E-Hg @ 80%	ACI + SDA @ 70%	ACI + SDA @ 80%
mil/kWh	4.05	4.23	4.11	4.59
\$/yr, 000's	11,559	12,063	11,720	13,090
mil/kWh Δ, 70% to 80%	0.18	--	--	0.48
\$/yr, 000's Δ, 70% to 80%	504	--	--	1,370

The results shown in Table 1.5-2 illustrate two observations. First, the addition of a wet FGD system (with or without E-Hg) for combined SO₂ and Hg control is economically competitive with similarly performing ACI + SDA systems. Factoring in potential operational cost increases such as the ash disposal concerns mentioned in Scenario 1, and the application of a wet FGD-based system becomes even more attractive. Secondly, increasing the Hg removal performance for the wet FGD-based system through the addition of E-Hg is significantly less expensive than increasing the carbon feed rate to achieve the same performance for the ACI + SDA system.

Scenario 3: New Wet FGD + E-Hg vs. ACI

In some instances with low-sulfur coal and SO₂ credit surplus, more stringent SO₂ emissions regulations will not require utilities to install new FGD control equipment. Any new equipment would be installed primarily for Hg control. For this scenario a 0.3% sulfur coal is being fired in the 500 MW model plant. A large portion of the low-sulfur coal is from the Western U.S. (sub-bituminous) where a much larger percentage of the mercury present in the flue gas is in the elemental form, which is not readily removed by wet FGD systems. Removal performance for the wet FGD estimates have been lowered to reflect an assumed 50:50 split between oxidized and elemental mercury. This does not affect wet FGD costs, only the corresponding ACI system. Similar to Scenario 2, this type of plant (low-sulfur, sub-bituminous coal, non-scrubbed, ESP-equipped) represents a potentially significant portion of the U.S. generating market (86,000 MW).

Table 1.5-3: Comparison of Wet FGD + E-Hg vs. ACI

ALC	Wet FGD @ 50%	Wet FGD + E-Hg @ 60%	ACI @ 60%
mil/kWh	4.05	4.23	0.85
\$/yr, 000's	11,559	12,063	2,426
SO ₂ credit, \$/yr 000's	946	946	--

Given the significant capital requirement for wet FGD systems, it is not surprising that installing these systems solely for Hg control will not generally be economically viable. Only in those situations where an increase in carbon content in the fly ash would result in significant operating cost increases (higher disposal costs, loss of by-product sale, etc.) would it potentially become attractive to install wet FGD for Hg control.

2.0 INTRODUCTION

2.1 BACKGROUND AND OBJECTIVES

A wide range of mercury emissions control performance for wet scrubbers in coal applications (0–96%) appear in the literature with a number of factors contributing to this variability. For example, significant differences in the mercury content of U.S. coals result in a wide range of mercury concentrations in the flue gas from the boiler. In addition, the form or species of mercury (elemental mercury or an oxidized compound such as HgCl_2) in the flue gas can affect wet FGD system mercury removal efficiency. Mercury speciation in the flue gas can be influenced by the type of coal fired, with sub-bituminous coal generating a higher relative proportion of elemental mercury than bituminous coal. The coal chlorine content and ash characteristics may also influence partitioning between the solid and vapor phases and the mercury species in the vapor phase. Finally, the scrubber spray tower configuration, liquid-to-gas ratio, and slurry chemistry may also impact the reported mercury emissions.

Wet FGD systems are currently installed on about 25% of the coal-fired utility generating capacity in the U.S., representing about 15% of the number of coal-fired units. Depending on the effect of the operating parameters mentioned above, FGD systems can provide cost-effective, near-term mercury emissions control options with a proven history of commercial operation. For boilers already equipped with FGD systems, the incremental cost of any vapor phase mercury removal achieved is minimal. To be widely accepted and implemented, technical approaches that improve mercury removal performance for wet FGD systems should also have low incremental costs and have little or no impact on operation and SO_2 removal performance.

The ultimate goal of this project was to commercialize methods for the control of mercury in coal-fired electric utility systems equipped with wet flue gas desulfurization (wet FGD). The two specific objectives of the project were 1) ninety percent (90%) overall system mercury removal and 2) costs below $\frac{1}{4}$ to $\frac{1}{2}$ of today's competing activated carbon mercury removal technologies. Overall system mercury removal is based on the mercury entering the system with the coal and the mercury leaving the system in the stack gas. In other sections, total mercury removal refers to the combined removal of the oxidized, elemental, and particulate mercury in the gas phase across the wet scrubber system.

2.2 BENEFITS OF THE B&W/MTI ENHANCED WET FGD MERCURY REMOVAL PROCESS

The primary benefit from the B&W/MTI enhanced wet FGD mercury removal process is the reduction of mercury emissions from coal-fired utility power plants. Other benefits are described below:

Cost-effective. B&W/MTI's technology is cost-effective because:

- *Use of existing equipment.* Little additional equipment will be required for implementation.

- *Low capital cost.* Because the technology requires little additional equipment and only minor modification of existing equipment for installation, capital costs are extremely low.
- *Low operating cost.* Currently, the most promising technology for mercury control alone is assumed to be activated carbon injection. Unfortunately, sorbent costs are high for carbon injection. The reagent used in B&W/MTI's technology is low in cost and readily available for application of the technology.

Co-Pollutant Control. Multiple pollutant analysis was recently documented in a report prepared by the U. S. EPA entitled, "Analysis of Emissions Reduction Options for the Electric Power Industry." The study looked at options to lower air emissions of sulfur dioxide (SO₂), fine particulate, mercury, and carbon dioxide (CO₂). The basic conclusion to the analysis was that an integrated, multi-pollutant approach to the control of these emissions could offer significant cost savings relative to a piecemeal approach. That conclusion applies directly to the use of wet FGD systems rather than activated carbon for mercury control since wet scrubbers capture multiple pollutants while activated carbon systems are normally applied for species at low concentrations, such as mercury.

Compatible with Current Emissions Control Technologies. The approach is ideally suited to wet FGD systems, since it utilizes existing equipment and provides mercury control with a proven history of commercial operation. The technology can be easily applied to both existing and new wet FGD systems from any supplier. All testing to date indicates that this approach has no adverse effects on wet scrubber performance or operation.

Performance Not Adversely Affected by Change in Power Plant Systems. In general, the power plant systems do not affect the mercury removal performance of the B&W/MTI enhanced wet FGD mercury removal technology. Furnace configuration, burner type, and plant size should have no effect on performance.

No Adverse Impact to By-Product Disposal or Usage. The B&W/MTI enhanced wet FGD mercury removal technology would not adversely affect the acceptability of the fly ash or gypsum products for sale while competing technologies such as activated carbon injection have the potential to dramatically increase the cost of disposal and/or limit its resale value.

2.3 PROJECT SPONSORS

The *Full-scale Testing of Enhanced Mercury Control for Wet FGD Systems Program* was funded by the U.S. Department of Energy's National Energy Technology Laboratory, the Ohio Coal Development Office within the Ohio Department of Development, and Babcock & Wilcox. Host sites and associated support were provided by Michigan South Central Power Agency and Cinergy.

3.0 TECHNICAL DISCUSSION

3.1 PROCESS DESCRIPTION

B&W/MTI's enhanced wet FGD mercury removal process adds very small amounts of a proprietary reagent to an existing wet FGD system to increase mercury removal efficiency.

3.2 TECHNICAL APPROACH

3.2.1 Overview

The goal of this project was to conduct full-scale, long-term, field-testing of B&W/MTI's enhanced wet FGD mercury removal technology to obtain mercury removal performance and cost data. Field-testing was completed at two commercial coal-fired utilities with wet FGD systems: 1) MSCPAs 55 MW_e Endicott Station and 2) Cinergy's 1300 MW_e Zimmer Station. Testing was conducted at these two locations because of the large differences in size and wet scrubber chemistry. Endicott employs a limestone, forced oxidation (LSFO) wet FGD system, whereas Zimmer uses Thiosorbic® Lime (magnesium enhanced lime) and *ex situ* oxidation. Both locations burn Ohio bituminous coal. Table 3.2-1 compares the characteristics of the two test locations.

Table 3.2-1: Test Location Characteristics Comparison

	MSCPAs Endicott Station	Cinergy Zimmer Station
Electricity Generation	55 MW _e	1300 MW _e
Number of Wet Scrubber Modules	1	6
Wet Scrubber Reagent	Limestone	Thiosorbic® Lime
Wet Scrubber Oxidation Method	<i>In situ</i> Forced Oxidation	<i>Ex situ</i> Forced Oxidation
Wet Scrubber Liquid-to-gas Ratio	78 gal/1000 acf	21 gal/1000 acf
Slurry pH	5.4 – 5.6	5.8 – 6.0
Inlet SO₂ Concentration	3600 ppm	3300 ppm
Gypsum Use	Cement	Wallboard

MSCPAs Endicott Station. Figure 3.2-1 shows MSCPAs Endicott Station. The plant is located in Litchfield, Michigan, approximately 40 miles southwest of Jackson, Michigan. Commercial operation began in November 1982. The power plant is rated at 60 MW_e and typically produces 50-55MW_e during the day and 30 MW_e at night. Approximately 140,000 tons of Ohio

bituminous coal are burned per year. The coal's higher heating value is 12,000 Btu/lb (as received) with a sulfur content of about 3%. The power plant is equipped with one B&W Stirling boiler, producing 480,000 lb/hr steam at 950°F and 1450 psig. A single ABB turbine handles the steam-to-electric power conversion.

The Endicott plant's air pollution control equipment includes one dry electrostatic precipitator and one wet scrubber. The precipitator is a Belco cold-side unit, having a flyash removal efficiency greater than 98%. It has three transformer-rectifiers rated at 38.5 KVA and five transformer-rectifiers rated at 58.5 KVA. No gas conditioning is used for precipitator operation.

A single absorber, *in situ* forced oxidation B&W wet scrubber is used for sulfur dioxide control. The reagent used is limestone slurry that is prepared in a crusher, tower mill, and classifier system. SO₂ removal is regulated at ninety (90%) percent with the wet FGD system typically achieving 92% SO₂ removal without the use of any additives. Primary dewatering is achieved with a thickener and secondary dewatering is accomplished with two Dorr-Oliver rotary drum vacuum filters. Approximately 28,000 tons/year of gypsum are produced and sold to concrete and agricultural concerns.



Figure 3.2-1: MSCPAs Endicott Station, Litchfield, Michigan

Cinergy Zimmer Station. Figure 3.2-2 shows Cinergy's Zimmer Station. The Cinergy Zimmer Station is located in Moscow, Ohio, 30 miles southeast of Cincinnati. The Zimmer generating station, rated at 1300 MW_e, was the world's first nuclear-to-coal conversion. The plant began

commercial operation in March 1991 and burns 3.5 million tons of Ohio bituminous coal per year. The power plant is equipped with a single B&W Carolina-type Universal Pressure boiler that produces 9775 million pounds of steam per hour at 1000°F and 3690 psig. The turbine generator system incorporates a Westinghouse low-pressure turbine generator set from the nuclear cycle with a new ABB high and intermediate pressure turbine generator.

The Zimmer station's air pollution control equipment includes two electrostatic precipitators for particulate control and six B&W wet scrubbers modules for SO₂ control, installed at the same time as the boiler and turbine. The precipitators are Flakt cold-side units having a 99.9% flyash removal efficiency. No gas conditioning is used for precipitator operation. The scrubbers employ Thiosorbic® (magnesium-enhanced) lime slurry as the reagent. The reagent preparation system consists of ball mills, classifiers, and slurry storage tanks. SO₂ removal efficiency is typically controlled at 92%, but the unit is capable of 95% removal efficiency with five absorbers operating.

The Zimmer wet FGD system was initially equipped and operated with thickeners for primary dewatering, and drum-type vacuum filters for secondary dewatering. In 2000, the dewatering system was upgraded by B&W to include an *ex situ* forced oxidation system to produce gypsum using hydroclones for primary dewatering and belt filters for secondary dewatering. The *ex situ* forced oxidation system was operational for this project.



Figure 3.2-2: Cinergy's Zimmer Station, Moscow, Ohio

3.2.2 Field Operation Phases

Figure 3.2-3 shows the project schedule and illustrates the testing phases necessary to demonstrate the commercial success of the B&W/MTI enhanced wet FGD mercury removal process. Field operation began at the Endicott Station. The phases of operation at the Endicott Station were as follows:

- Parametric testing to define the optimal operating parameters for the process.
- Two weeks of verification testing to verify the performance of the process with the selected operating conditions.
- Four months of long-term operation to continue the verification of the amount of mercury removal achieved and to prove that there were no long-term effects on SO₂ removal, materials of construction, or by-product utilization.

After completing field operation at the Endicott Station, the B&W/MTI enhanced mercury removal system was moved to the Zimmer Station for testing. Field operation at the Zimmer Station included:

- Two weeks of verification testing to verify the performance of the process with the selected operating conditions. Reagent was added to all operating wet scrubbers modules simultaneously.

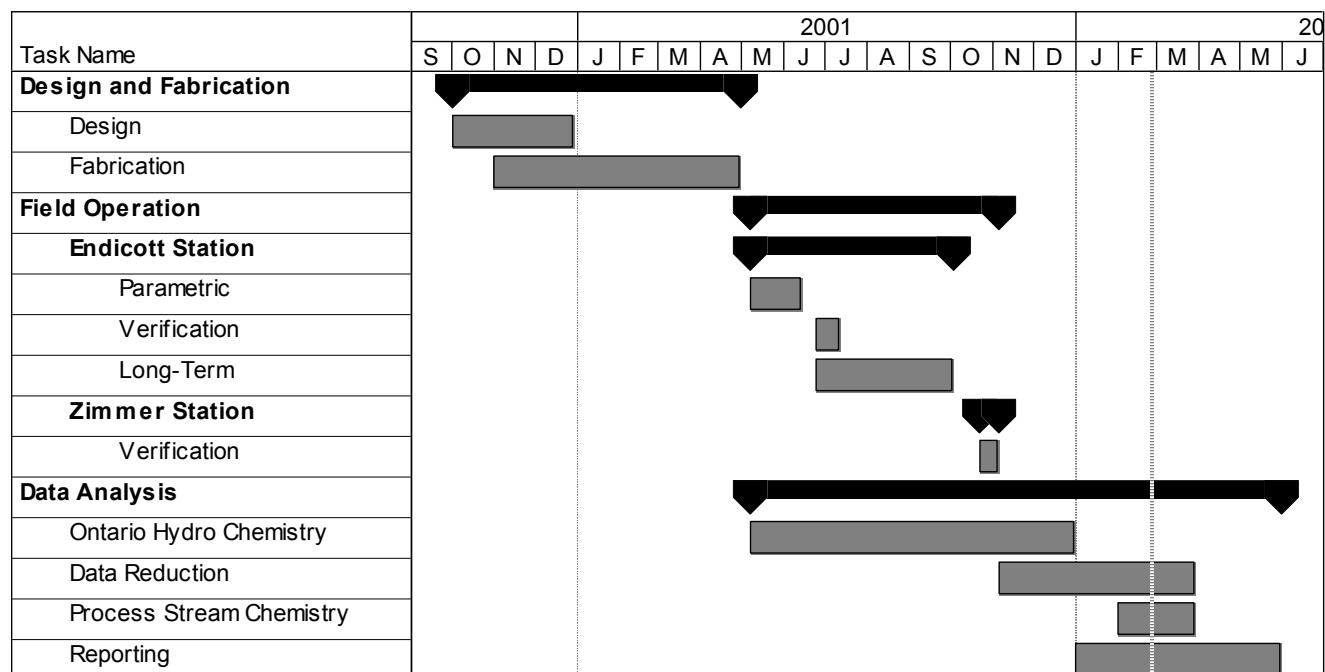


Figure 3.2-3: Project Schedule

3.2.3 Mobile Test Pump Skid

To facilitate minimal construction and set-up at each plant site, a mobile equipment skid was fabricated to connect to the existing wet scrubber systems at the Endicott and Zimmer Stations. A picture of the equipment skid is shown in Figure 3.2-4. An equipment drawing is shown in Figure 3.2-5.



Figure 3.2-4: Reagent Injection Skid

A tank truck of additive solution was used as the on-site storage vessel. A NPS chemical transfer hose was used to connect the skid to the additive tank truck, plant water system, and wet FGD absorber recirculation piping. Stainless steel piping was used to connect the components on the skid. A large and small additive injection/metering pump were mounted on the skid, one for the MSCPA Endicott test, and one for the Cinergy Zimmer test. The pumps were equipped with variable frequency controllers, which permitted a 100:1 turndown. The skid was also equipped with a dilution water system for added flexibility in varying additive feed concentration. A calibration tube was provided upstream of the pumps to check pump delivery rates. A pulsation dampener, having a flexible elastomeric bladder/diaphragm and a gas-pressurized upper chamber, was located in the pumps' common discharge line to facilitate a more uniform feed flow. Also provided were flow meters, flow control valves, pressure regulating valves, pressure

gauges, and a pressure relief valve. All equipment, pipe, valves and fittings were made of 316 stainless steel, with suitable elastomers where required. Only minor modifications to the existing wet FGD equipment were required to connect the reagent feed line to the plant's slurry system. After testing was complete, the hose connections to the tank truck, absorber recirculation pump suctions and plant water supply were disconnected, the skid's power hook-up was detached, and the skid was shipped to MTI for storage. It is available for future testing.

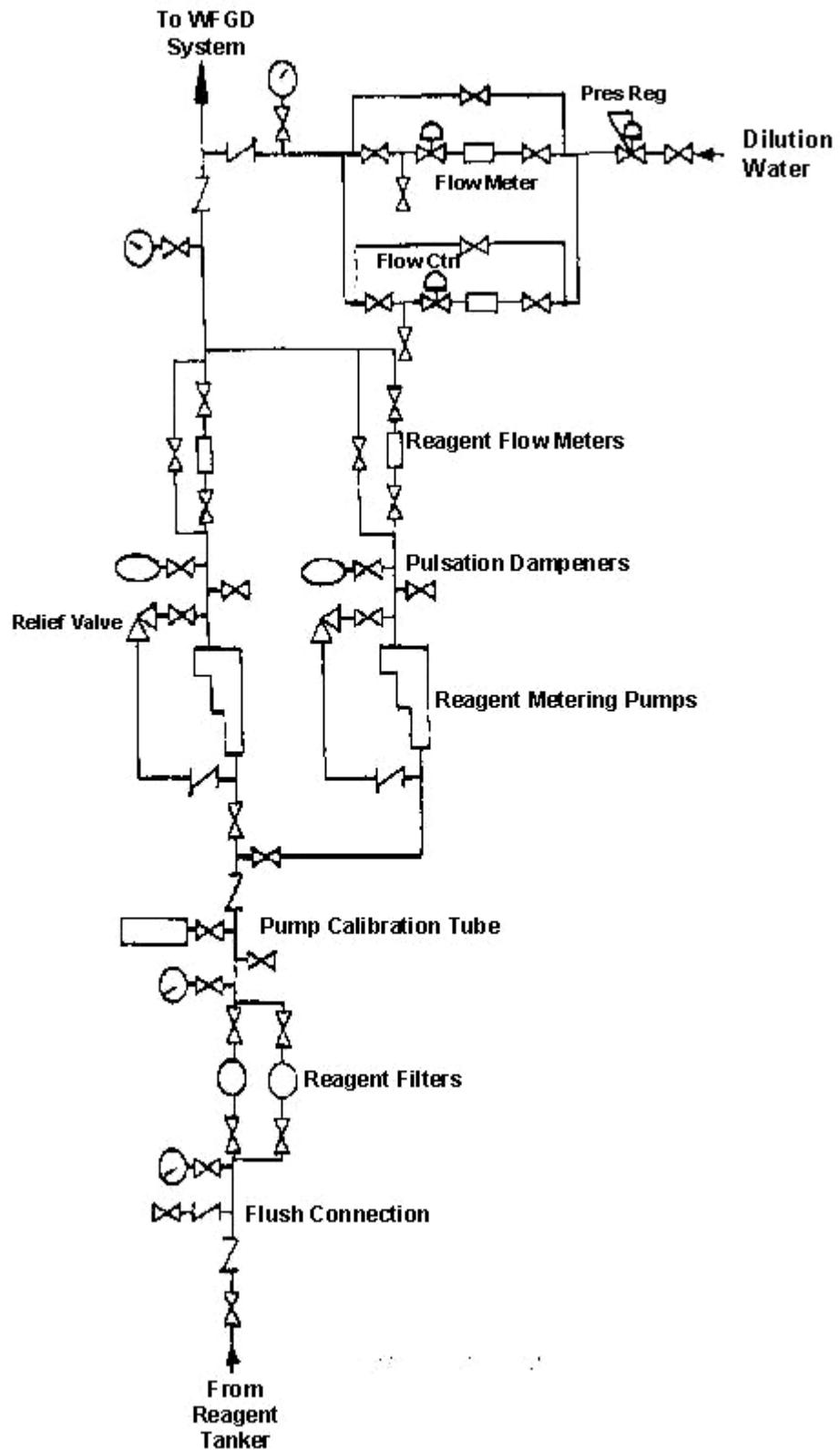


Figure 3.2-5: Reagent Injection Skid Equipment Schematic

3.2.4 Ontario Hydro Measurements – General Methodology

The Ontario Hydro (OH) Method was used to measure total and speciated mercury emissions during all testing phases of this program. A variation of EPA Method 29, this method applies to the determination of particulate and gaseous metals emissions from industrial, utility, and municipal sources. Particulate and gaseous emissions are withdrawn isokinetically from a source and pass through a quartz fiber filter and solutions of potassium chloride (KCl), acidic peroxide and acidic potassium permanganate (KMnO₄). The oxidized forms of mercury collect in the KCl impingers and elemental mercury collects in the peroxide and potassium permanganate impingers. Highlights of the procedures used in the method include:

- Potassium permanganate was added to the KCl impingers immediately after the post-sampling leak check to prevent the loss of oxidized mercury during recovery of the sample. Typically, 3-6 ml of KMnO₄ were needed to achieve the desired purple endpoint.
- A nominal sampling time of two hours was used at all locations. The mercury collected in the impingers remained well above the analytical detection limits.
- The particulate filter was maintained at the flue gas temperature (to a maximum of 340 °F) or a minimum of 275 °F.
- Nozzle diameters were selected to achieve a target isokinetic sampling rate of 0.5 to 0.6 dscfm (dry standard cubic feet per minute).
- The same sampling probe assembly was used at a given location for each test to minimize variation between runs that may result from the breakdown and reassembly of different sampling equipment.

The impinger solutions from the Ontario Hydro Method sample trains were analyzed for mercury using Cold Vapor Atomic Absorption Spectroscopy (CVAAS). This method was used to determine both the elemental and ionic forms of mercury. The analysis follows EPA reference method SW7470 (CVAAS).

The flue gas sampling port locations and planned traverse points were consistent (to the extent that the duct sizes can be traversed with normally available equipment) with EPA Method 1 - Sample and Velocity Traverses for Stationary Sources. Method 1 specifies the minimum number of traverse points required for the flue diameter and proximity to flow disturbances. The sampling details for each location at each of the demonstration sites are summarized in Table 3.2-2. Sampling performed at both stack locations was conducted through 4 sample ports, located 90° from each other around the circumference of the stack. Sampling performed at both inlet locations was conducted through multiple ports in the same plane (as indicated in the table).

Table 3.2-2: Flue Gas Sampling Details

	MSCPA – Endicott Station	Cinergy – Zimmer Station		
	Wet FGD Inlet	Wet FGD Outlet (Stack)	Wet FGD Inlet	Wet FGD Outlet (Stack)
Flue Dimensions (W x D), ft.	8 x 10.75	--	37.5 x 37.5	--
Stack Diameter, ft.	--	10	--	42.7
Flue Orientation	Vertical	--	Horizontal	--
Port Diameter (in.)	4	4	4	4
Number of Ports	5	4	3	4 (2 used)
# Traverse Points	25 (5 x 5)	12 (4 x 3)	12 (3 x 4)	12 (2 x 6)
# Sampling Planes	1	1	1	1
Gas Temperature (°F)	350 - 370	120 - 130	330 - 350	120 – 130
Nominal Pressure (in. H ₂ O)	-7	+0.4	-19	-0.9
Filter Temperature (°F)	340	275	340	275

Sample train and equipment preparation and recovery took place in a fully equipped, mobile laboratory trailer shown in Figures 3.2-6 and 3.2-7.



Figure 3.2-6: Laboratory Trailer (Exterior)



Figure 3.2-7: Laboratory Trailer (Interior)

3.2.5 PS Analytical Mercury Analyzer System

An on-line mercury analyzer system, manufactured by PS Analytical (PSA), was used during field-testing with the hope of obtaining real-time mercury trending.

PSA first introduced the amalgamation atomic fluorescence spectrometer for gaseous phase measurement of total mercury in 1991. It was initially used for ambient air and natural gas sampling. The basic principle of operation is that gas samples are drawn across a gold trap (Amasil tube) to capture mercury. The trap is then heated to release mercury that is delivered to an atomic fluorescence detector. In 1996, PSA introduced a system for on-line measurement of mercury in flue gas from coal-fired boilers. Final design of the system continues with input from the Energy and Environmental Research Center (EERC) at the university of North Dakota, B&W/MTI, and U.S. DOE. The specifications for the instrument are in Table 3.2-3. A schematic arrangement of the current design for on-line speciation/total mercury determination is shown in Figure 3.2-8 and a photograph of the analyzer is shown in Figure 3.2-9.

Table 3.2-3:PS Analytical Mercury Analyzer Specifications

Detection Limit:	5ng/m ₃ (2.5 liter sample)
Linear Range:	300 $\mu\text{g}/\text{m}^3$ (2.5 liter sample)
Sampling Frequency:	5 minutes
Gas Requirements:	0.8 l/min-1 Argon, Nitrogen or Air
Calibration Techniques:	Vapor Injection – Absolute Permeation source with concentration range selection
Reducant (for total Hg):	2 ml/min (Speciation Accessory)
Buffer (for Hg ⁰):	2 ml/min (Speciation Accessory)
Relative Accuracy:	Within $\pm 15\%$ of EPA Methods

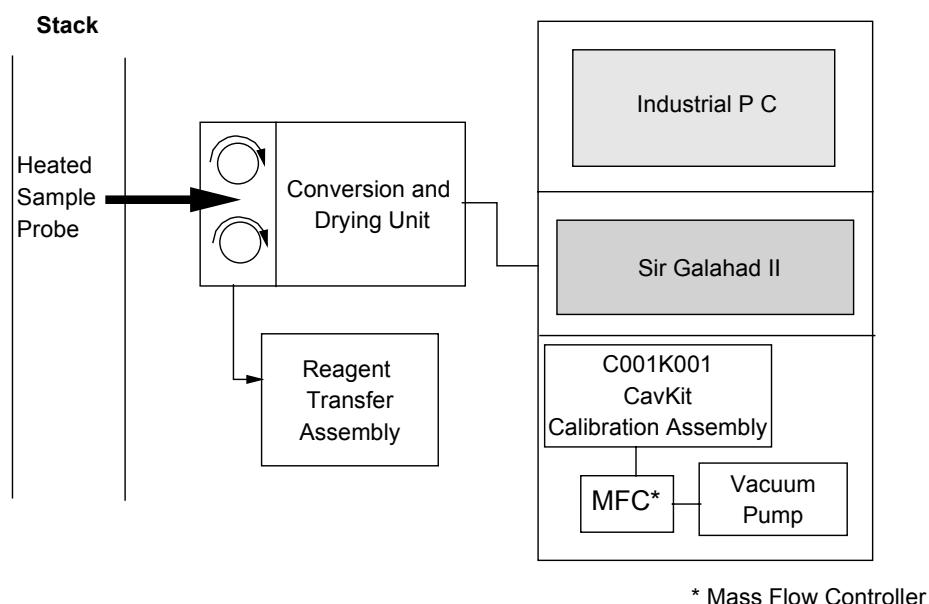


Figure 3.2-8: PS Analytical Mercury Analyzer Schematic



Figure 3.2-9: PS Analytical Mercury Analyzer

The PSA Mercury Analyzer System did not perform as expected throughout this program. The analyzer itself performed very well, but there were a host of problems with the preconditioning system. At no time during the six-month project did the system perform well enough to have confidence in using the data to make a definitive statement about the mercury removal process or plant performance. Therefore, this section will be dedicated to “lessons learned” in the hope that some of the improvements made to the system will benefit others. It is assumed that the reader is familiar with the PSA equipment and gas sampling methods in the following discussion.

1. SO₃ Aerosol – Both Zimmer and Endicott have reported high levels of SO₃ in the flue gas. When this gas is cooled, as occurs in the preconditioner impingers, the SO₃ condenses and forms an aerosol that is not scrubbed by the impingers. This aerosol eventually built up on the walls of the long (175 ft) transfer lines, absorbed water vapor to form sulfuric acid, and scrubbed mercury out of the gas sample. The build up of acid was verified by flushing the lines with distilled water and measuring the pH of the flush water which was often as low as 2. To alleviate this problem, the connection between the precondition oven and impingers was modified to include a coil of 1/8-inch tubing. The purpose of the coil was to

act as an inertial separator to remove the aerosol by forcing it to collide with the tubing walls.

2. Peltier Upgrade – Early in the test, condensation in the transfer lines caused several problems. The Peltier coolers were upgraded to double the cooling capacity. It is important that the treated gas be completely dry if long transfer lines are used.
3. 3-Way Solenoid Valve – Several times during the project the drains on the Peltier coolers plugged with various kinds of precipitate, and overflowed. Normally, this did not cause a serious problem because the overflow trips a moisture sensor and shuts down the chemical pumps. However, this particular system is configured so that the gas pump remains on. If not corrected, moisture in the flue gas continues to condense in the cooler and overflows into the transfer line along with the impinger chemicals. Eventually, the overflow floods the switch box and the analyzer gold trap, necessitating cleaning and repair. To correct this problem Teflon[®], 3-way solenoid valves were incorporated into the system so that a trip of the moisture sensors also switched the 3-way valve to divert the gas flow into a waste container.
4. Black Precipitate – Early in the test, the cooler drain plugged several times with a black precipitate. The impinger chemistry was adjusted to avoid precipitation.
5. White/Yellow Precipitate – On several occasions, a whitish/yellow deposit formed on the impinger glassware. The material was very difficult to dissolve in either acids or bases. At the time, it was believed that the deposit had no effect on Hg because the impinger chemistry is designed to evolve all mercury. However, in a later discussion with other mercury CEM users, it was learned that this deposit could absorb mercury and, in fact, could explain some of the strange behavior seen on several occasions. For example, on one occasion an ID fan at Zimmer tripped and caused an emergency shut down of the entire plant. Immediately after the trip, the mercury value spiked off-scale and remained there for several hours even though the analyzer was only sampling air. One explanation is that in normal operation the impinger chemistry reduced some of the SO₂ in the gas to sulfur that deposited on the glassware and tubing. The sulfur absorbed some of the mercury and gradually built up. The reaction stayed in relative equilibrium as long as the chemistry remained constant. However, when the boiler tripped, the source of sulfur was eliminated and the deposit began to dissolve releasing the trapped mercury back into the gas. This not only explains this one strange occurrence, but can also account for the low mercury values, as compared to the O-H measurements, seen throughout the project. The best comparisons ever obtained during the project were only about half of the Ontario Hydro Method values. Since this problem was not identified until after the project, it is uncertain how to correct for it.
6. Cool Spots – Early in the test, the measured mercury would occasionally spike to high values for short periods. These spikes were identified by the manufacturer as an indication of a cool spot before the impingers. It is postulated that oxidized mercury condenses in cool spots and builds up until it is swept into the impinger with water droplets. Several modifications were tested, but the one that worked best involved better insulation between

the oven and impinger, increasing the velocity between the oven and impinger by replacing a short length of $\frac{1}{4}$ -inch tubing with $\frac{1}{8}$ -inch tubing, and installing an $\frac{1}{8}$ -inch T immediately after the oven. Water was injected into the bottom of the T to quickly quench the gas.

7. Long Transfer Lines – 175 ft, heated, Teflon[®] sample hoses were used to transport the conditioned gas from the preconditioners to the analyzer in the lab trailer. Tests with gas spiked with Hg⁰ from the PSA CAV Kit showed that the transfer lines did absorb some mercury, especially if they were contaminated with acid from the flue gas. The only solution to this is to locate the analyzer and preconditioners as close to the sample points as possible, but this is often very costly or logically unfeasible.
8. Ash Filter – On several occasions the mercury values would suddenly drop. Often times, but not always, this could be corrected by replacing the particulate filter in the heated sample box. These occurrences could not be consistently correlated to anything happening in the plant, like soot blowing, bringing on or taking off a burner, switching pulverizers, etc., but it is likely related to some combustion situation that produces soot or unburned carbon that collects on the filter and absorbs mercury. The color of ash deposits on the filter varied from almost white to black. To minimize this, the filter was changed before every set of O-H tests. Apogee makes a “virtual” filter that may have merit in this application.

3.3 ONTARIO HYDRO FLUE GAS SAMPLING RESULTS

In the following sections mercury speciation and removal data are shown in several figures. Unless otherwise indicated, the following figure description will apply:

- Each pair of bars in a given figure represents the average wet FGD inlet and outlet total gas phase mercury concentrations for a given test. Each bar is further divided to show oxidized and elemental mercury concentrations. The number above the outlet bar represents the average total mercury removal across the wet FGD system for that test. The error bars represent the maximum and minimum total mercury concentration for each location and each test.
- During the course of the program, particulate phase Hg concentrations were also determined at the wet FGD systems inlet and outlet. These concentrations averaged less than 1% of the total present in the flue gas and thus are not shown in the figures in the following sections.

3.3.1 MSCPAs, Endicott Station

3.3.1.1 MSCPAs Test Plan

Three phases of testing were conducted at the Endicott Station: Parametric, Verification, and Long-Term. The purpose and objectives of these phases were as follows:

- Parametric – testing completed over a range of reagent feed rates to achieve three incremental mercury removal levels between 40% and 90% and to provide performance curve and cost data. In all, 8 tests were completed during this phase. A summary of the parametric tests and number of O-H sample trains conducted during each test is given in Table 3.3-1.

Table 3.3-1: Summary of Parametric Tests – Endicott

Test ID	Reagent Feed Rate, gph	No. of Inlet Trains	No. of Outlet Trains
5/8/01-1	Baseline, (0.0 gph)	3	4
5/16/01-2	2.9	2	2
5/17/01-3	0.29	3	3
5/18/01-4	0.07	3	3
6/11/01-5	Baseline, (0.0 gph)	3	3
6/12/01-6	0.18	2	2
6/13/01-7	0.29	3	3
6/14/01-8	1.0	2	3

- Verification – testing began immediately following the Parametric test phase to demonstrate consistent day-to-day operation and mercury removal performance. This phase spanned 16 days; 14 sets of inlet and outlet OH sample trains (one set per day) were conducted.
- Long-Term – following the completion of the Verification test phase, four months of long-term operation were conducted to not only continue verification of mercury removal performance, but to demonstrate that there were no long-term deleterious effects on SO₂ removal, materials of construction, or by-product utilization. During this test phase, 8 tests were conducted with triplicate sets of OH sample trains performed for each test.

For all phases of the test program conducted at Endicott, OH sampling was conducted at both the wet FGD inlet (upstream of the ID fan) and wet FGD outlet (on the stack). Pictures of each sampling location are shown in Figures 3.3-1 (inlet) and 3.3-2 (outlet). In Figure 3.3-1 the 5 inlet sampling ports are located behind the narrow horizontal strip of lagging material.



Figure 3.3-1: Wet FGD Inlet Sampling Location - Endicott



Figure 3.3-2: Wet FGD Outlet (Stack) Sampling Location - Endicott

3.3.1.2 Plant Operation

A summary of the major operating parameters for the 3 test phases conducted at Endicott is shown in Table 3.3-2 (all of the Endicott DAS data may be found in Appendix B). Each line in the table corresponds to a set of inlet and outlet O-H sample trains. The listed value for a given operating parameter from a specific test represents the average of values stored by the data acquisition system (at 15 second intervals) during that test. For the Parametric and Long-Term tests, triplicate sets of O-H measurements were conducted (except as indicated); these are indicated by the letter 'A', 'B', or 'C' within the Test ID value. For example, the Test ID '051701-3B' refers to the second set of O-H inlet and outlet sample trains, conducted during Test 3 on May 17, 2001. Whenever possible, tests were conducted with the plant at full-load. Tests conducted at less than full-load conditions, especially during the Verification tests, were due to reduced grid power requirements.

Table 3.3-2: Summary of Plant Operating Conditions – Endicott

Ontario Hydro	Reagent Flow	Plant CO ₂ In	Plant CO ₂ Out	Plant SO ₂ In	Plant SO ₂ Out	Plant SO ₂ Removal Efficiency	Plant Load	WFGD Temp In	Plant Temp Stack
Test ID	gph	%	%	ppm (wet)	ppm (wet)	%	MW	°F	°F
Parametric Tests									
050801-1A	0.00	10.3	12.3	1206	88	93.9	59	358	116
050801-1A1	0.00	10.0	12.0	1218	120	91.8	56	359	117
050901-1B	0.00	9.7	12.1	1387	130	92.5	59	354	116
050901-1C	0.00	9.5	11.9	1520	144	92.4	61	361	118
050901-1D	0.00	9.4	11.9	1438	137	92.5	60	368	119
051601-2A	2.93	9.3	11.7	1543	172	91.1	59	358	118
051601-2B	2.90	8.9	11.4	1605	187	90.9	55	350	118
051701-3A	0.29	9.3	11.8	1797	196	91.4	58	352	119
051701-3B	0.30	9.7	12.0	1700	177	91.5	58	361	121
051701-3C	0.30	10.0	12.1	1616	164	91.6	59	371	123
051801-4A	0.07	9.5	11.8	1647	179	91.3	57	352	120
051801-4B	0.06	9.5	11.8	1668	189	90.9	58	357	119
051801-4C	0.06	9.8	11.8	1710	184	91.1	56	357	120
061101-5A	0.00	9.3	11.9	2385	396	87.3	56	351	121
061101-5B	0.00	9.3	11.8	2047	200	92.3	53	358	123
061101-5C	0.00	9.3	11.9	1815	234	89.9	56	367	123
061201-6A	0.17	9.8	11.9	1793	172	92.1	56	352	120
061201-6B	0.17	10.0	12.0	1681	155	92.3	55	362	122
061301-7A	0.29	9.9	12.1	1449	157	91.2	54	355	122
061301-7B	0.26	9.7	11.9	1626	197	90.2	53	361	123
061301-7C	0.30	9.6	11.9	1553	149	92.3	53	371	124
061401-8A	1.01	9.8	12.0	1568	155	91.9	53	352	122
061401-8B	1.04	10.0	12.0	1448	144	91.8	53	362	122
061401-8C	1.02	10.0	12.1	1605	164	91.5	53	364	122
Verification Tests									
062501-9A	1.03	10.1	13.0	1983	204	92.0	57	375	122
062601-10A	1.01	9.8	12.7	2052	259	90.3	56	364	121
062701-11A	0.99	12.6	11.3	1917	134	94.9	55	365	122
062801-12A	1.00	11.9	10.9	1827	191	87.5	57	360	121
062901-13A	1.00	11.8	10.4	1916	146	91.3	55	361	122
063001-14A	1.00	11.7	10.1	1683	124	91.4	55	366	124
070101-15A	1.00	10.4	8.9	1634	95	93.3	38	332	117
070201-16A	1.00	11.3	10.4	1904	117	93.3	44	322	112
070601-17A	1.00	12.4	9.8	1711	100	92.6	47	340	118
070701-18A	1.00	11.3	8.9	1489	76	93.5	37	322	117
070801-19A	1.00	11.6	9.4	1552	84	93.3	44	359	122
070901-20A	1.00	12.1	11.8	1945	138	92.7	57	364	122
071001-21A	1.00	11.8	10.5	1690	102	93.2	56	365	122
071101-22A	1.00	10.4	10.8	1820	126	93.3	58	355	118
Long Term Tests									
071201-23A	1.00	12.2	11.2	1935	140	92.1	57	349	118
071201-23B	1.00	12.4	11.4	1980	147	91.9	57	356	119
071201-23C	1.00	12.2	11.8	1839	139	92.2	56	362	120
072401-24A	1.00	12.4	9.5	2033	125	92.0	57	366	124
072401-24B	1.00	12.7	9.4	2175	150	90.7	56	371	125
072401-24C	1.00	12.4	9.1	2272	240	85.6	55	376	126
080701-25A	1.00	12.0	10.8	1745	130	91.6	48	347	122
080701-25B	1.00	12.1	10.4	2095	170	90.6	46	354	124
080701-25C	1.00	12.0	10.2	2311	225	88.6	45	360	125
082101-26A	0.99	12.3	10.6	1801	130	91.6	54	343	119
082101-26B	0.99	12.3	10.5	1984	154	90.9	56	354	120
082101-26C	0.99	12.5	10.7	1857	143	91.0	58	366	120
090501-27A	1.00	12.4	10.8	1924	149	91.1	56	346	119
090501-27B	1.00	12.2	10.8	1911	146	91.3	56	355	120
090501-27C	1.00	12.3	10.5	1845	140	91.1	57	365	120
091801-28A	1.00	12.2	10.6	1949	153	90.9	57	358	119
091801-28B	1.00	12.2	10.6	1982	159	90.8	57	367	119
091801-28C	1.00	12.5	10.7	2046	163	90.7	57	373	120
100201-29A	1.00	12.8	11.9	2157	233	88.4	59	366	121
100201-29B	1.00	12.7	10.9	2091	238	86.8	59	373	121
100201-29C	1.00	12.8	10.9	1975	190	88.7	59	377	122
100301-30A	0.00	12.5	10.9	2271	214	89.2	56	348	119
100301-30B	0.00	12.5	11.0	2374	385	81.6	59	368	121
100301-30C	0.00	12.7	11.1	2336	502	75.6	59	374	120

3.3.1.3 Parametric Test Results

In Figures 3.3-3 and 3.3-4 the mercury removal performance across the scrubber and speciation results for the 8 parametric tests are shown as a function of reagent feed rate. The first 4 tests (baseline + 3 feed rates) are shown in Figure 3.3-3; the last 4 tests (baseline + 3 feed rates) are shown in Figure 3.3-4. No reagent was injected during the baseline tests. All 8 parametric tests were conducted with the plant operating at full-load (55 MW). Due to problems with the mercury analyzer system, the last four parametric tests were conducted 3 weeks after the first four tests to allow time to analyze the sample trains and interpret the findings. As a result of this delay, a second baseline test was performed to establish a new benchmark for the subsequent tests.

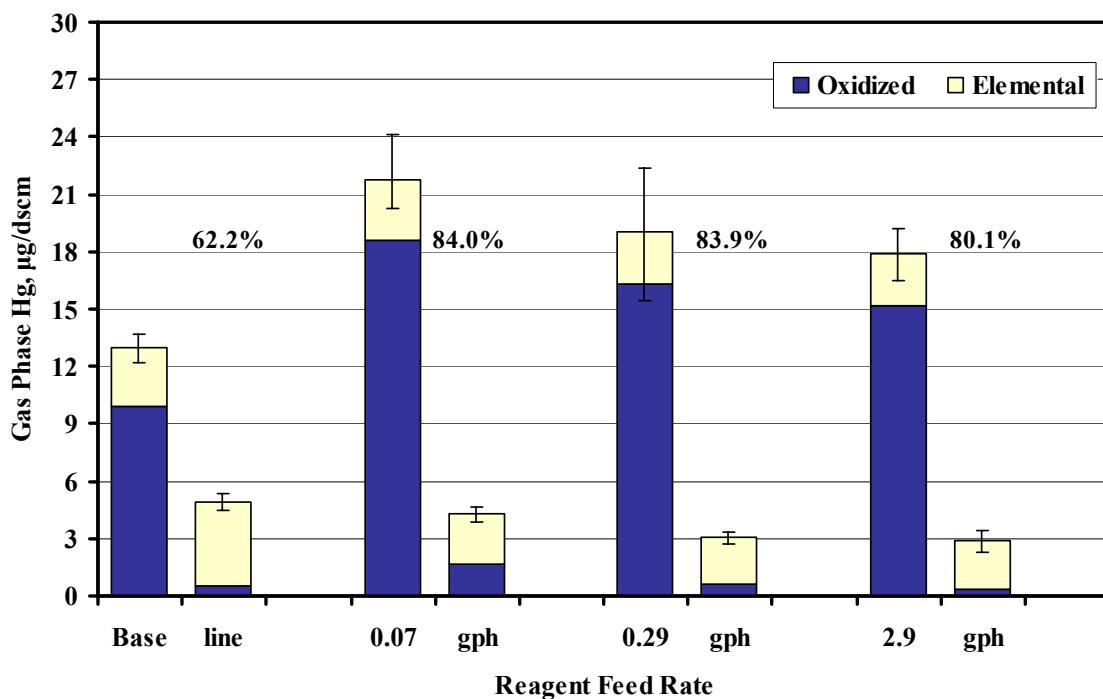


Figure 3.3-3: Hg Speciation Summary, Parametric Tests 1 - 4

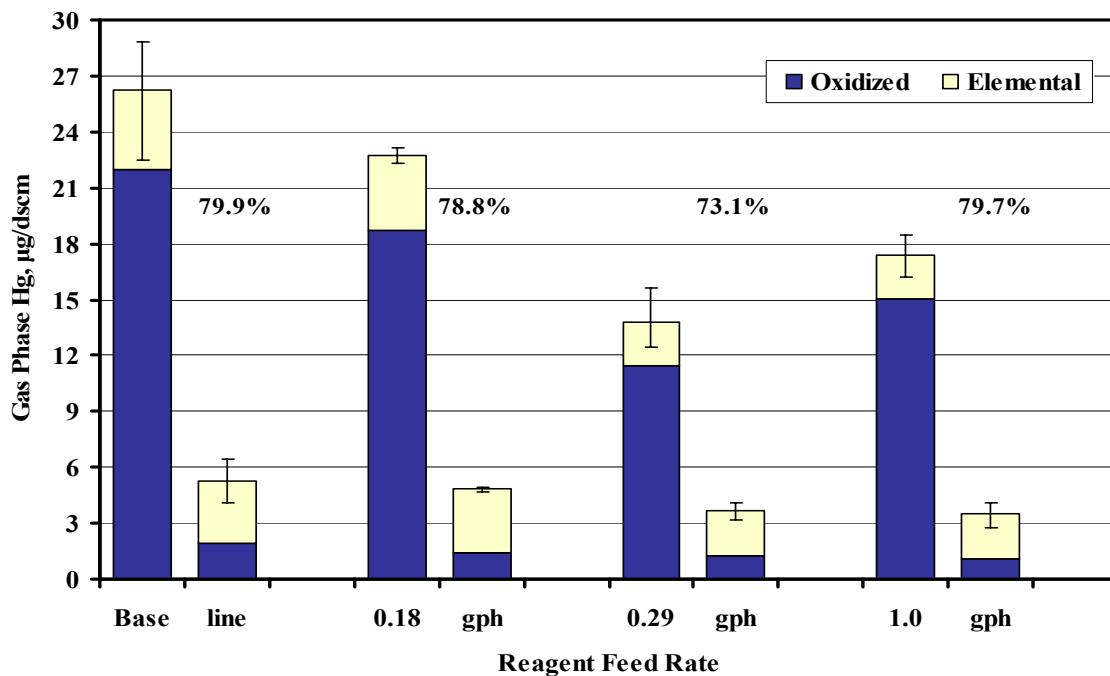


Figure 3.3-4 Hg Speciation Summary, Parametric Tests 5 - 8

Several interesting observations are apparent based on the data presented in the above figures. First, the mercury concentration in the flue gas entering the wet FGD system varies widely. For example, even though the 4 tests shown in Figure 3.3-4 were conducted on consecutive days, the average inlet gas phase mercury concentration ranged from 13 to 26 µg/dscm. Because Endicott fires up to four different Ohio coals (at varying sulfur concentrations), primarily based on spot market availability, this level of variation is not entirely unexpected. As a result, judging the effectiveness of the mercury control technology cannot be entirely based on removal performance alone. Consequently, simply comparing the mercury removal performance between the 0.18 gph and 0.29 gph tests shown in Figure 3.3-4 (without further analysis) would yield an erroneous conclusion regarding the reagent performance, namely, decreasing removal performance vs. increasing reagent feed rate. This is due to the fact that oxidized mercury is much more readily captured in wet FGD systems and that there was nearly twice as much oxidized mercury present in the inlet flue gas for the 0.18 gph test than for the 0.29 gph test, resulting in a falsely low bias for the 0.29 gph test.

As mentioned previously, the mercury control technology utilized during this program enhances mercury control in two ways: 1) increasing oxidized mercury removal performance, and 2) suppressing the reemission of mercury, already captured by the wet FGD system, in the elemental form. By evaluating the mercury removal performance with respect to the wet FGD outlet flue gas mercury concentration and speciation, a more meaningful performance curve can be generated. In Figure 3.3-5, the average outlet mercury speciation results for the 8 parametric tests are shown as a function of reagent feed rate. In the figure, the two baseline tests have been averaged (the elemental/oxidized ratio for both baseline tests was similar). The upper set of error

bars represents the maximum and minimum elemental mercury concentration for each test; the lower represents the maximum and minimum oxidized mercury concentration. The general trend is for decreasing mercury concentration (total, oxidized and elemental) with increasing reagent feed rate. This trend is illustrated more clearly in Figure 3.3-6, utilizing an X-Y plot to show total outlet gas phase mercury concentration as a function of reagent feed rate. The error bars shown in the figure represent the maximum and minimum total gas phase mercury concentration for each test.

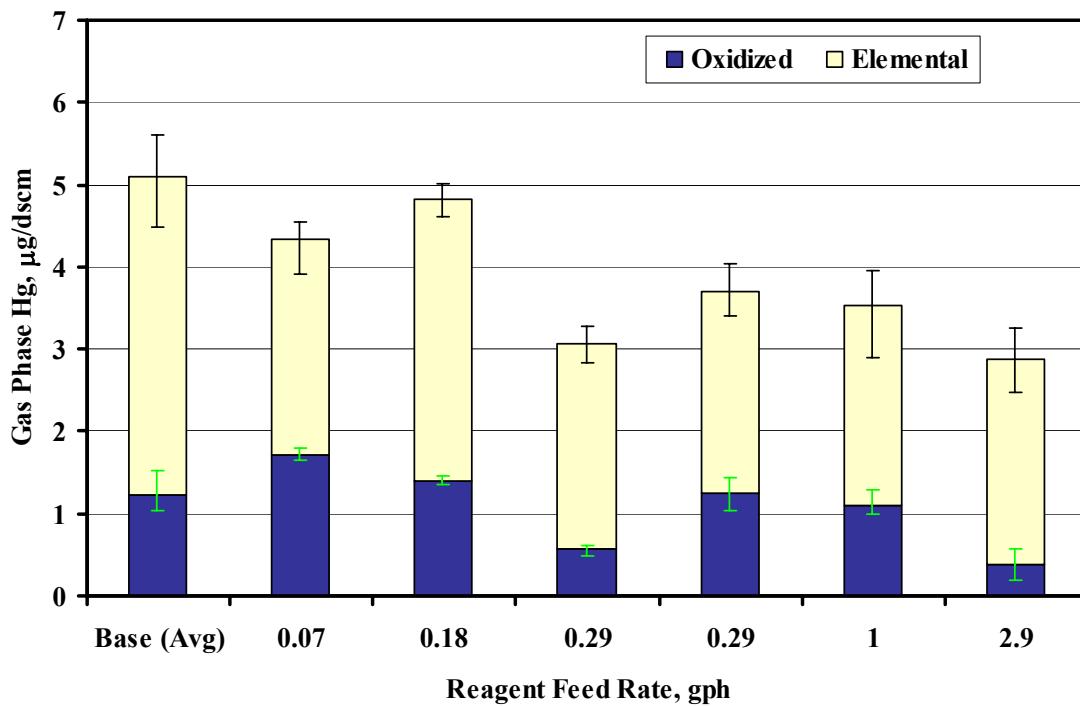


Figure 3.3-5: Summary of Wet FGD Outlet Hg Speciation, Parametric Tests

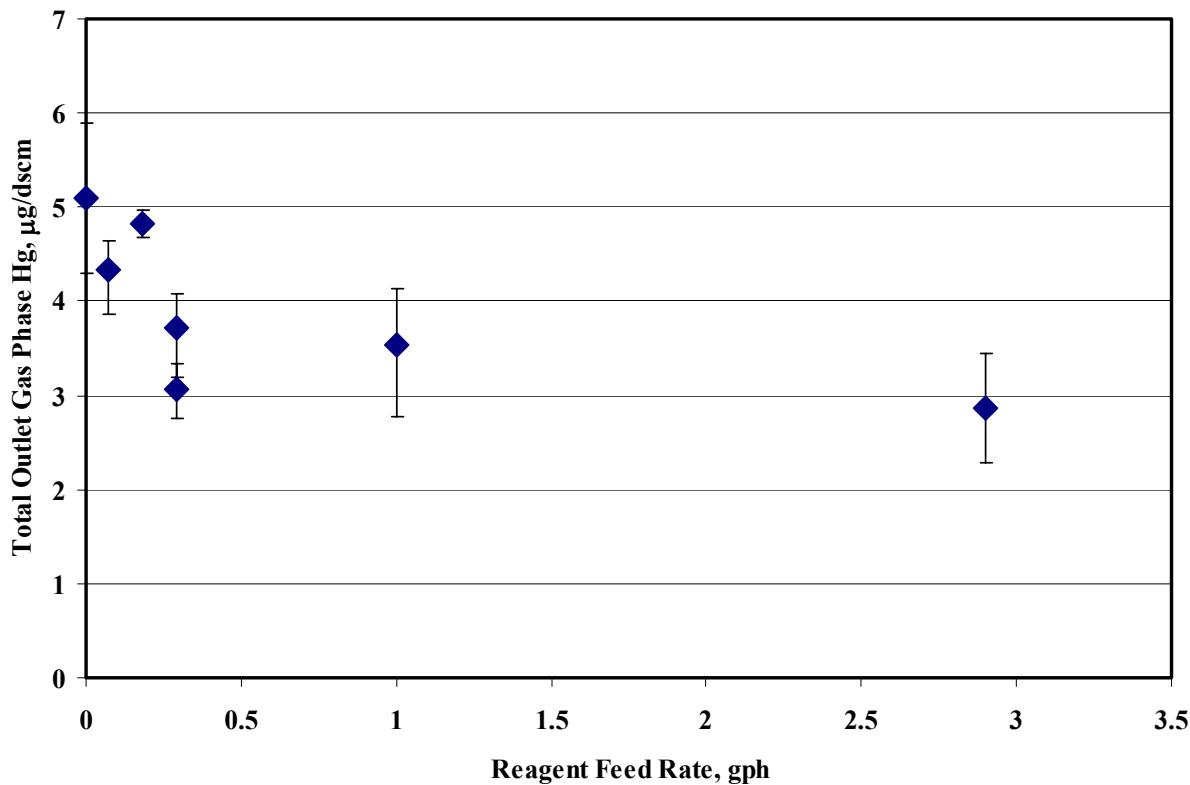


Figure 3.3-6: Effect of Reagent Feed Rate on Outlet Hg Concentration - Endicott

In order to conduct the Verification and Long-Term phases of the Endicott demonstration program, it was necessary to determine a reagent feed rate that would 1) provide high mercury removal performance, 2) maintain high removal performance regardless of inlet mercury concentrations, and 3) be low enough to allow a direct scale-up (same reagent/flue gas ratio) for the Zimmer demonstration program using the existing reagent feed system. Thus, although maximum mercury control was achieved with a reagent feed rate of 2.9 gph, the corresponding feed rate for the Zimmer demonstration would have exceeded the design capacity of the feed system. A reagent feed rate of 1 gph was therefore chosen for the Verification and Long-Term phases. With this feed rate the corresponding Zimmer demonstration feed rate fell below the feed system design capacity. Additionally, any fluctuations in inlet mercury concentration would be less likely to adversely affect removal performance, since similar mercury control performance was observed for the 0.29 and 1 gph tests (offering 3 to 4 times the amount of reagent to absorb the impact of concentration fluctuations).

3.3.1.4 Performance Verification Test Results

Verification testing, designed to demonstrate consistent day-to-day operation and removal performance, spanned 16 days; 14 sets of inlet and outlet OH sample trains (one set per day, test numbers 9 through 22) were conducted during this period. In Figure 3.3-7 a graphical summary of the speciation results for the 14 verification tests is shown. Each set of bars represents one

inlet and outlet set of OH sample train measurements. The average mercury removal across the wet FGD system for the Verification testing phase was 76%. A tabular summary of the results is given in Table 3.3-3.

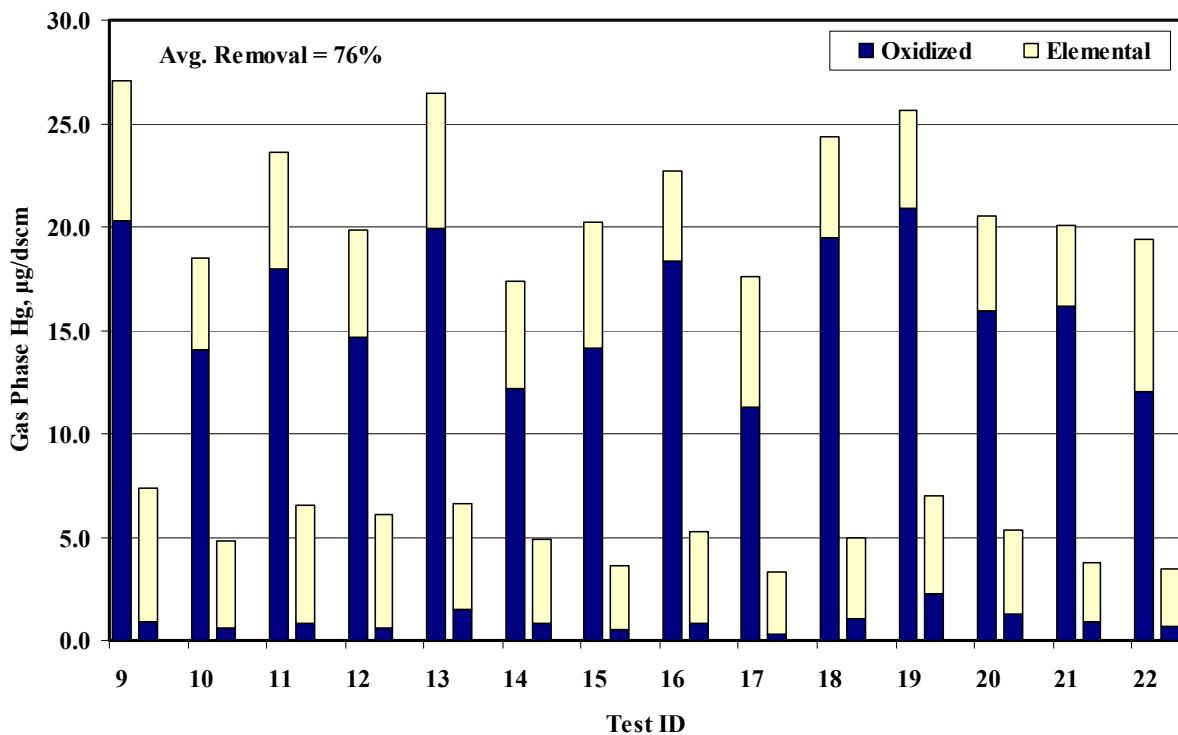


Figure 3.3-7: Summary of Hg Speciation Results - Endicott Verification Tests

Table 3.3-3: Summary of Hg Speciation Results - Endicott Verification Tests

	Average	Maximum	Minimum
Wet FGD Inlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	21.7	27.1	17.3
Oxidized	16.2	20.9	11.2
Elemental	5.4	7.4	3.9
Hg Speciation, %			
Oxidized	75	--	--
Elemental	25	--	--
Wet FGD Outlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	5.2	7.3	3.3
Oxidized	0.9	2.3	0.3
Elemental	4.3	6.4	2.7
Hg Speciation, %			
Oxidized	18	--	--
Elemental	82	--	--
Wet FGD Hg Removal, %			
Total	76.1	82.3	69.3
Oxidized	93.5	--	--
Elemental	19.5	--	--

The data summaries shown in Figure 3.3-7 and Table 3.3-3 illustrate two important points: 1) the control technology performed as expected with high oxidized mercury removal and suppressed reemission of mercury from the scrubber in the elemental form, and 2) due to the speciation percentages, very high total mercury removal performance across the wet FGD system (>90%) is not possible without some type of mercury oxidation technology upstream of the wet FGD system. These observations will be discussed in greater detail below.

In Figure 3.3-8 the effectiveness of the control reagent, at the chosen feed rate of 1 gph, is shown. During the course of the Verification tests, the inlet oxidized mercury concentration ranged from approximately 11 to 21 $\mu\text{g/dscm}$. Because wet FGD systems capture oxidized mercury much more readily than elemental, large fluctuations in the oxidized mercury concentration will be more likely to affect the overall mercury removal performance. The outlet oxidized mercury concentration remained essentially constant over the range of inlet oxidized

mercury concentrations. This would indicate that the 1 gph feed rate was sufficient to adequately account for the variations in inlet mercury concentration experienced during day-to-day operation by maintaining high levels of oxidized mercury removal across the scrubber, regardless of inlet oxidized mercury concentration.

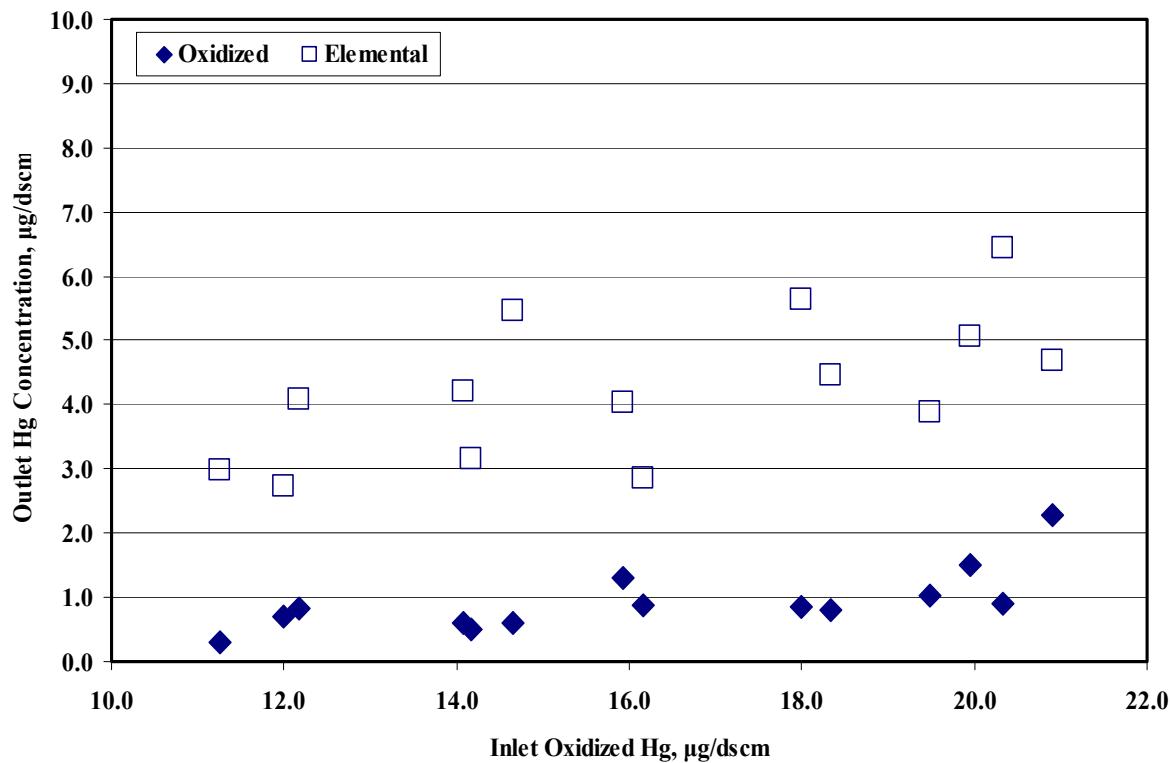


Figure 3.3-8: Outlet Oxidized and Elemental Hg Concentration vs. Inlet Oxidized Hg Concentration

In Figure 3.3-9, the outlet elemental mercury concentrations from the Verification tests are shown as a function of inlet elemental mercury concentration. A 45° line, representing equal inlet and outlet concentrations, is included in the figure for reference. Data points above and to the left of the 45° reference would represent conditions where mercury is being reemitted from the scrubber in the elemental form; points to the right and below the line correspond to conditions where mercury reemission is suppressed. All but one of the data points fall on or below the 45° line, indicating that mercury reemission was suppressed.

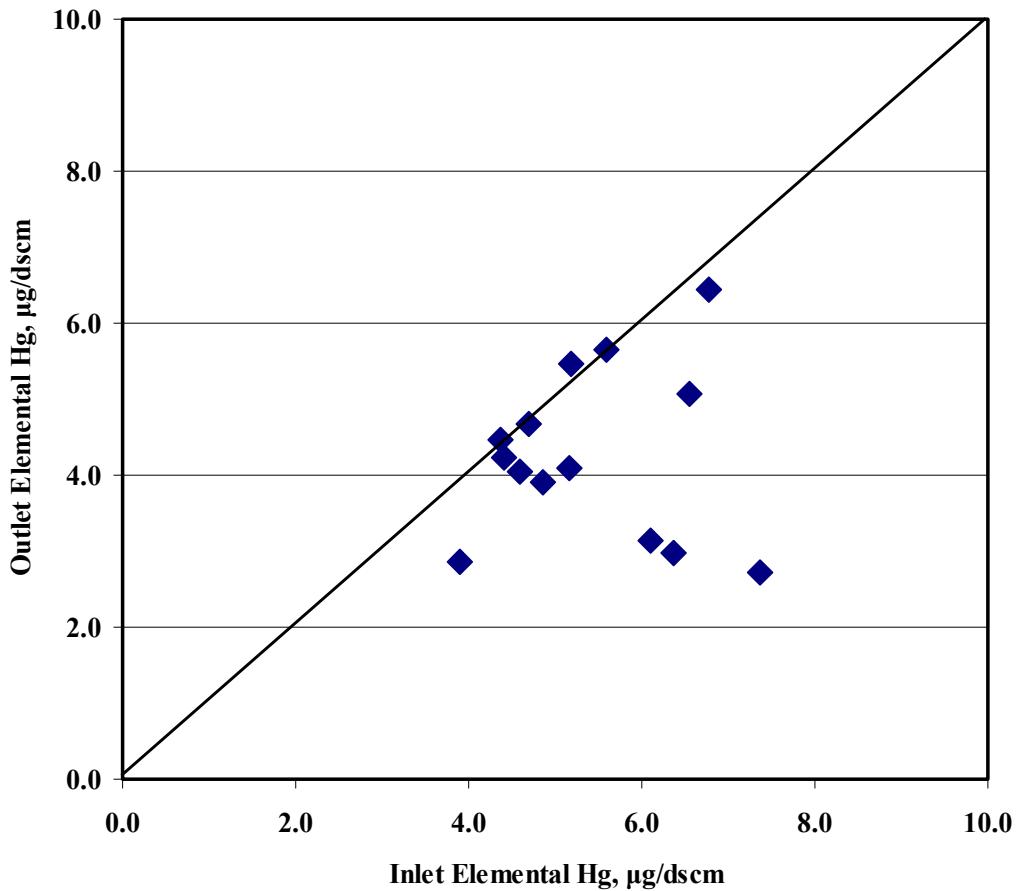


Figure 3.3-9: Outlet vs. Inlet Elemental Hg, Verification Tests - Endicott

3.3.1.5 Long-Term Operation

Immediately following the Verification tests, four months of long-term operation were conducted at a reagent flow of 1 gph to continue verification of mercury removal performance and to demonstrate that there were no long-term deleterious effects on SO₂ removal, system operations, or by-product utilization. During this test phase, 8 tests were conducted at two week intervals with triplicate sets of OH sample trains performed for each test (test numbers 23 through 30). In Figure 3.3-10, a graphical summary of the mercury speciation results is shown for 6 of the 8 tests conducted during this test phase. Due to gas sampling and analytical problems, the results for Test 23 are not included in the figure. The last Long-Term test (Test 30) was originally intended to be a final baseline test. However, it was discovered after the run that reagent, from dead legs in the feed system, was mixing with flush water and being fed to the wet FGD system. Because neither the feed rate nor the length of time the reagent feed was on could be verified, the speciation results for this test were not included in the figure.

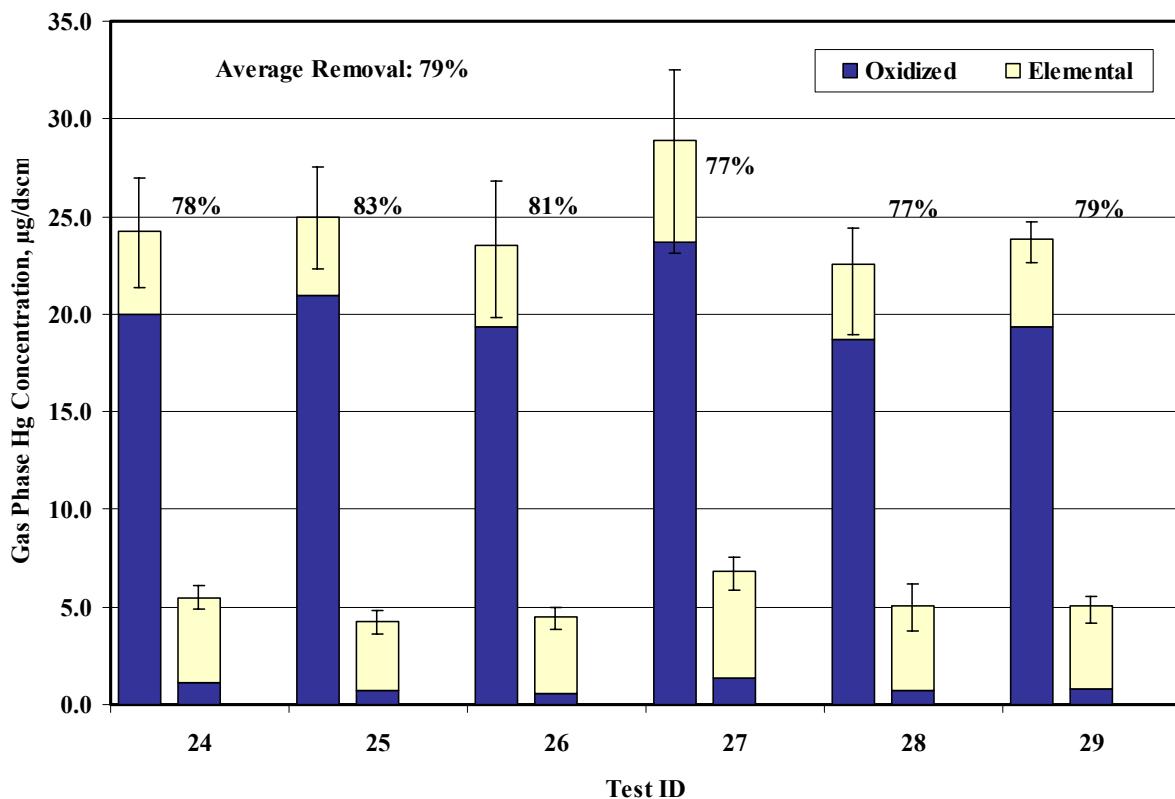


Figure 3.3-10: Summary of Hg Speciation Results - Endicott Long-Term Tests

The average mercury removal across the wet FGD system for the Long-Term testing phase was 79%. A tabular summary of the results is given in Table 3.3-4. As was observed during the Verification tests, the control technology performed as expected, providing very high oxidized mercury removals (95.7%) while simultaneously suppressing reemission of the captured mercury (no increase in elemental mercury concentration across the scrubber). The level of total removal across the scrubber (79%) was once again limited by the speciation percentages of the inlet flue gas (82% oxidized, 18% elemental).

Similar to Figure 3.3-9, the outlet elemental mercury concentrations for the Long-Term and Verification tests are shown in Figure 3.3-11 as a function of inlet elemental mercury concentration. The data indicate the continued success at suppressing the reemission of captured mercury in the elemental form [2 of the 6 reported tests showed a very slight increase in elemental mercury concentration across the wet FGD system (<0.5 µg/dscm for both tests)].

Table 3.3-4: Summary of Hg Speciation Results - Endicott Long-Term Tests

	Average	Maximum	Minimum
Wet FGD Inlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	24.2	32.5	18.9
Oxidized	19.9	27.2	11.2
Elemental	4.3	5.9	2.9
Hg Speciation, %			
Oxidized	82	--	--
Elemental	18	--	--
Wet FGD Outlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	5.2	7.6	3.6
Oxidized	0.9	1.5	0.2
Elemental	4.3	6.1	3.1
Hg Speciation, %			
Oxidized	17	--	--
Elemental	83	--	--
Wet FGD Hg Removal, %			
Total	79.0	83.9	67.3
Oxidized	95.7	--	--
Elemental	0.8	--	--

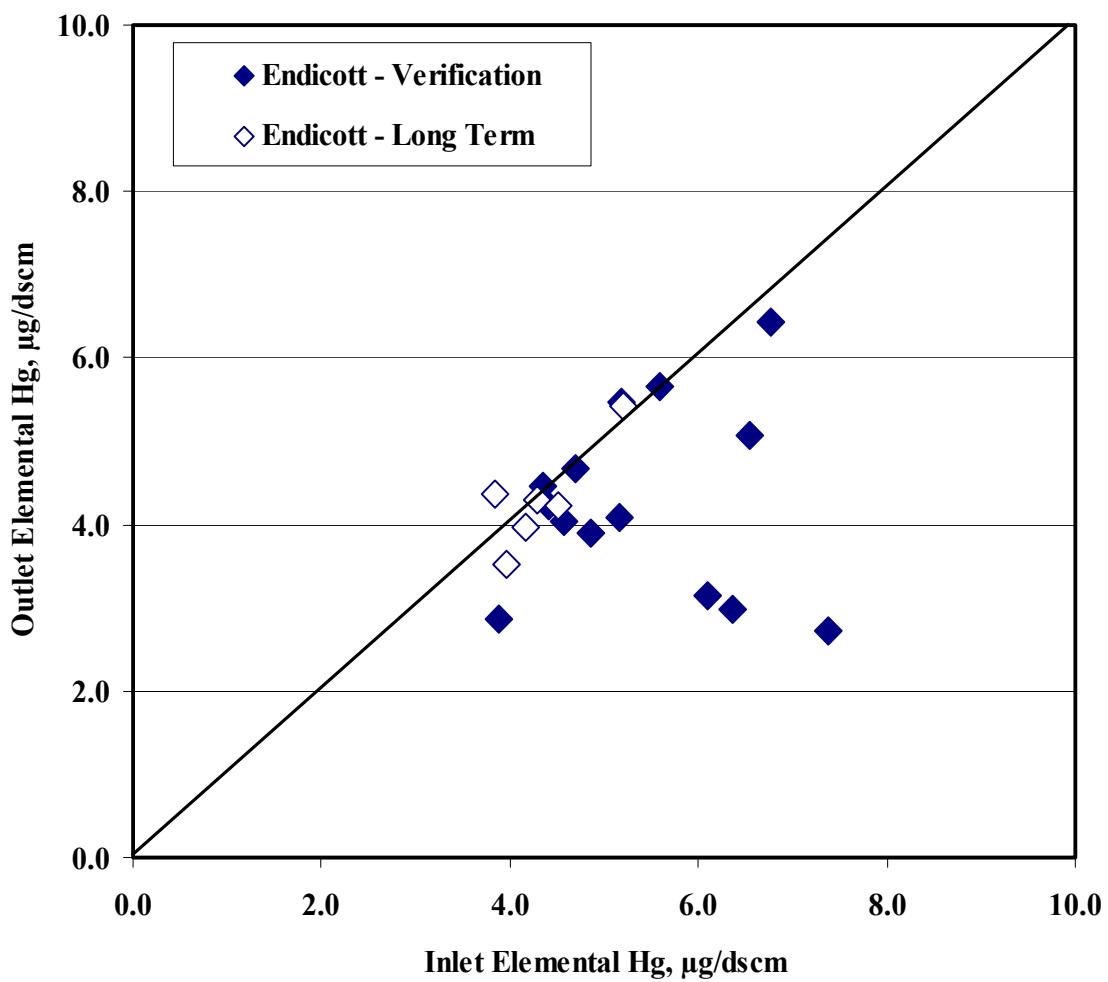


Figure 3.3-11: Outlet vs. Inlet Elemental Hg, Verification and Long-Term Tests - Endicott

3.3.2 Cinergy, Zimmer Station

3.3.2.1 Test Plan

Two weeks of Verification testing were conducted during this phase of the demonstration program. During these tests one set of inlet and outlet OH sample trains was conducted each day (for a total of 13 sets during reagent feed to the wet FGD system), with the exception of the baseline test; two sets of sample trains were performed for this test. For all of the tests conducted at Zimmer, OH sampling was conducted at both the wet FGD inlet (common duct upstream of the six ID fans) and wet FGD outlet (on the stack). Pictures of each sampling location are shown in Figures 3.3-12 (inlet) and 3.3-13 (outlet). In Figure 3.3-12, two of the inlet sampling ports are visible on either side of the walkway platform where the sampling equipment is located; the third sampling port is located at the centerline of the flue, in the middle of the walkway. In Figure 3.3-13, the sampling platform used during this program is second from the bottom of the picture.

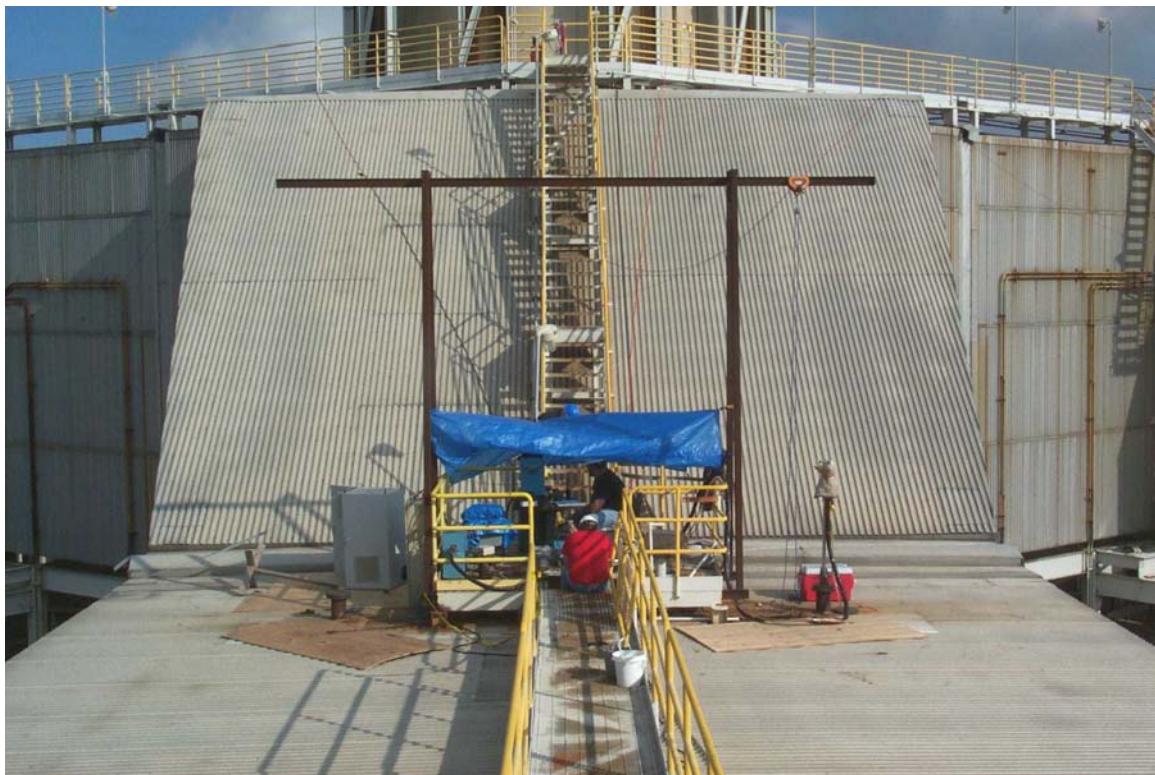


Figure 3.3-12: Wet FGD Inlet Sampling Location - Zimmer



Figure 3.3-13: Wet FGD Outlet Sampling - Zimmer

3.3.2.2 Plant Operation

A summary of the major operating parameters for the Verification tests conducted at Zimmer is shown in Table 3.3-5 (all of the Zimmer data acquisition system (DAS) data may be found in Appendix B). As with the Endicott data shown previously, each line in the table corresponds to a set of inlet and outlet O-H sample trains. The listed value for a given operating parameter from a specific test represents the average of values stored by the plant's DAS (at 6 minute intervals) during that test. Whenever possible, tests were conducted with the plant at full-load. Tests conducted at less than full-load were due to reduced grid power requirements. Zimmer is equipped with six scrubber modules (five operating and one spare). The spare module is indicated by 'OFF' in the pH section and by the low temperatures in module temperature section. Reagent was injected into all operating modules simultaneously.

Table 3.3-5: Summary of Plant Operating Conditions – Zimmer

O-H Test ID	Date/Time of OH Test Start	Reagent Flow	Net Load	ESP 1	ESP 2	Inlet	SO ₂	Stack SO ₂	SO ₂ Removal	Inlet CO ₂	Stack CO ₂	Mod 1	Mod 2	Mod 3	Mod 4	Mod 5	Mod 6
				Opacity	Opacity							gph	MW	%	%	ppm	ppm
31A	10/23/2001 10:15		0.0	1302	0.9	1.9	2536	430	80.0	13.0	11.1	6.3	6.2	6.2	6.4	6.2	5.9
31B	10/23/2001 13:45		0.0	1305	0.8	1.4	2465	184	91.0	12.9	11.1	OFF	6.6	6.5	6.7	6.5	6.7
32A	10/24/2001 10:17		27.2	1304	0.9	5.3	2457	193	90.9	12.8	10.9	OFF	6.2	6.3	6.4	6.3	6.0
33A	10/25/2001 11:00		27.3	1307	0.4	13.9	2857	237	90.4	12.7	10.9	OFF	6.4	6.4	6.5	6.4	6.0
34A	10/26/2001 11:00		27.3	1304	1.1	1.1	2748	197	91.7	12.9	11.0	OFF	6.3	6.3	6.4	6.3	6.1
35A	10/27/2001 9:26		27.4	1303	1.3	0.9	2335	162	92.0	12.5	10.8	OFF	6.2	6.2	6.3	6.2	6.2
36A	10/28/2001 8:32		27.2	1131	0.7	0.6	2370	174	91.7	12.0	10.4	OFF	6.0	6.1	6.2	6.1	6.1
37A	10/29/2001 9:30		27.2	1299	0.7	1.1	1957	132	92.4	12.4	10.8	OFF	6.2	6.4	6.4	6.2	6.2
38A	10/30/2001 9:30		27.3	1302	1.2	1.7	2521	171	92.2	12.9	11.1	OFF	6.3	6.5	6.3	6.3	6.3
39A	11/1/2001 8:00		27.2	1304	0.9	1.3	2582	153	93.1	12.5	10.8	6.4	6.5	6.4	6.3	OFF	6.5
40A	11/2/2001 8:00		27.2	1301	1.3	2.5	2233	166	91.5	12.4	10.8	6.0	6.0	5.9	6.0	OFF	6.0
41A	11/3/2001 8:45		27.2	819	0.7	1.1	868	84	89.4	10.9	9.5	6.0	6.1	6.1	6.1	OFF	6.0
42A	11/4/2001 8:00		27.2	821	0.8	1.6	1580	109	92.2	10.8	9.4	6.4	6.5	6.5	6.7	OFF	6.7
43A	11/5/2001 8:22		27.2	1305	1.5	0.7	2581	200	90.7	12.8	11.0	6.5	6.3	6.6	6.2	OFF	6.5
44A	11/6/2001 8:00		40.7	1302	1.1	0.6	2577	207	90.6	12.7	10.8	6.3	6.3	6.4	6.3	OFF	6.3

O-H Test ID	Date/Time of OH Test Start	Mod 1	Inlet	Mod 1	Mod 2	Mod 2	Mod 3	Mod 3	Mod 4	Mod 4	Mod 5	Mod 5	Mod 6	Mod 6	Mod 6	Mod 6	Mod 6
			°F	Outlet °F	Inlet °F	Outlet °F	Inlet °F	Outlet °F	Inlet °F	Outlet °F	Inlet °F	Outlet °F	Inlet °F	Outlet °F	Inlet °F	Outlet °F	Inlet °F
31A	10/23/2001 10:15		123	123	349	131	359	132	359	126	355	128	344	BadTC			
31B	10/23/2001 13:45		91	106	349	130	360	133	361	127	357	129	354	BadTC			
32A	10/24/2001 10:17		74	70	330	127	359	132	359	127	355	129	345	BadTC			
33A	10/25/2001 11:00		59	59	342	126	352	130	353	124	350	126	333	BadTC			
34A	10/26/2001 11:00		46	51	342	125	353	128	354	124	350	125	328	BadTC			
35A	10/27/2001 9:26		45	55	342	125	353	129	350	123	347	125	328	BadTC			
36A	10/28/2001 8:32		42	58	333	125	343	130	341	123	337	125	317	BadTC			
37A	10/29/2001 9:30		50	67	346	127	356	131	353	125	349	126	338	BadTC			
38A	10/30/2001 9:30		55	68	350	129	360	131	359	126	355	127	347	BadTC			
39A	11/1/2001 8:00		349	129	355	128	353	130	349	124	72	85	333	BadTC			
40A	11/2/2001 8:00		355	131	361	131	360	131	355	126	72	69	340	BadTC			
41A	11/3/2001 8:45		349	126	355	125	351	127	354	121	60	58	325	BadTC			
42A	11/4/2001 8:00		346	125	351	124	348	127	350	121	54	54	319	BadTC			
43A	11/5/2001 8:22		356	129	361	127	358	128	353	125	56	55	328	BadTC			
44A	11/6/2001 8:00		349	131	355	128	352	129	344	123	52	54	322	BadTC			

3.3.2.3 Performance Verification Results

Verification testing at Zimmer was designed to demonstrate consistent day-to-day operation and removal performance. Because the Zimmer wet FGD system is Thiosorbic® Lime-based, evaluation of the control technology performance with this system was essential to aid in determining the applicability of the technology to various wet FGD processes. Verification testing spanned 15 days and included 14 tests (one baseline, 13 with reagent - test numbers 31 through 44). In Figure 3.3-14 a graphical summary of the speciation results for 13 of the verification tests is shown. Test 44, conducted at a 50% higher reagent feed rate, is not shown, but no appreciable improvement in mercury removal performance across the scrubber was observed. With the exception of the baseline test, each set of bars represents one inlet and outlet set of O-H sample train measurements; the baseline test results are the average of two sets of sample trains. Unless indicated, all tests were conducted at full-load (1300 MW). The average mercury removal across the wet FGD system for the Verification testing phase was 51%. A tabular summary of the results is given in Table 3.3-6.

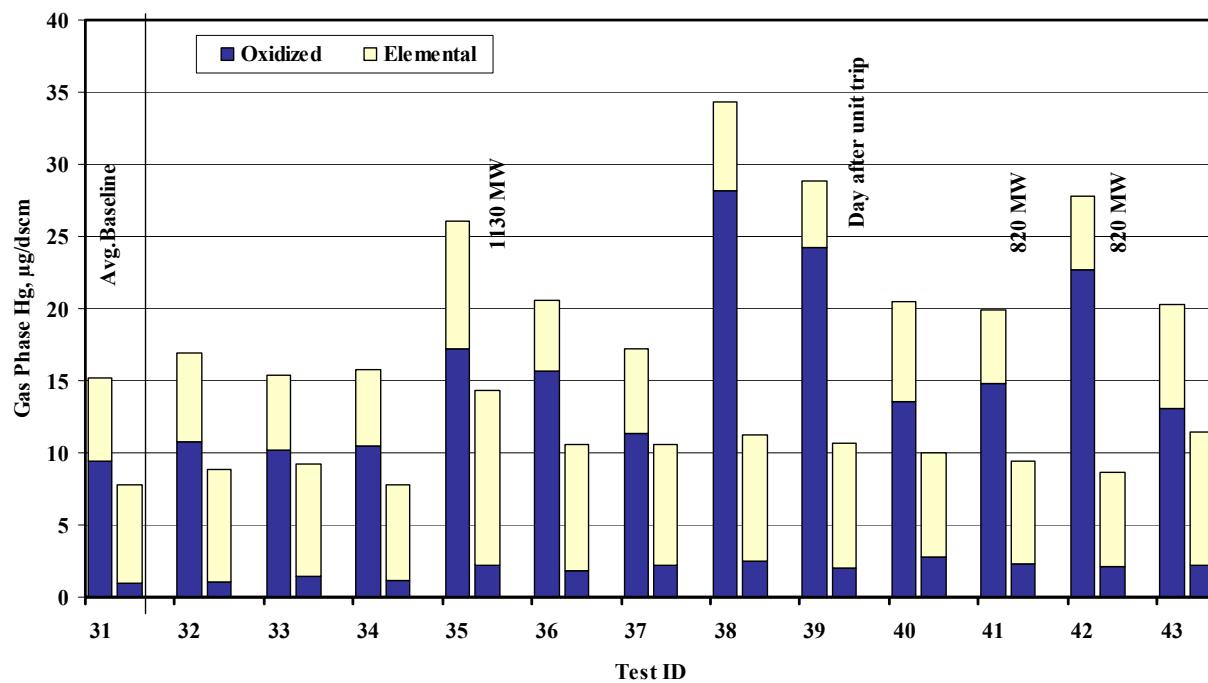


Figure 3.3-14: Summary of Hg Speciation Results – Zimmer Verification Tests

Table 3.3-6: Summary of Hg Speciation Results – Zimmer Verification Tests

	Average	Maximum	Minimum
Wet FGD Inlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	22.6	34.3	15.4
Oxidized	16.6	28.2	10.2
Elemental	6.0	8.8	4.6
Hg Speciation, %			
Oxidized	74	--	--
Elemental	26	--	--
Wet FGD Outlet			
Hg Concentration, $\mu\text{g/dscm}$			
Total	10.3	14.3	7.8
Oxidized	2.0	2.8	1.1
Elemental	8.3	12.2	6.6
Hg Speciation, %			
Oxidized	19	--	--
Elemental	81	--	--
Wet FGD Hg Removal, %			
Total	51.4	68.8	38.3
Oxidized	86.8	--	--
Elemental	(41.3)	--	--

It is evident from the data presented in Figure 3.3-14 that the control technology was not successful in preventing mercury captured in the absorber from being reemitted as elemental mercury. For each test, the elemental mercury concentration at the outlet of the wet FGD system was higher than the inlet. Over the entire Zimmer demonstration, an average of 40% *more* elemental mercury was present in the outlet flue gas versus that found in the inlet flue gas. Additionally, the control technology did not improve oxidized mercury removal, since oxidized mercury concentrations at the outlet were approximately twice as high as those observed during the Endicott demonstration (2.0 vs. 0.9 $\mu\text{g/dscm}$, on average). Two factors appear to be the cause of the poor performance during the Zimmer demonstration:

- Low inlet oxidized mercury concentration – Excluding the 3 tests where the inlet oxidized mercury concentration exceeded 20 $\mu\text{g}/\text{dscm}$, the average inlet oxidized mercury concentration for the Zimmer tests was approximately 13 $\mu\text{g}/\text{dscm}$, 3 $\mu\text{g}/\text{dscm}$ lower than the Endicott Verification tests and 7 $\mu\text{g}/\text{dscm}$ lower than the Endicott Long-Term tests. When combined with the higher outlet oxidized mercury concentrations, oxidized mercury removal for the Zimmer tests averaged 86.7% (85% when excluding the 3 high inlet tests), significantly less than the 94 – 96% removal observed at Endicott.
- Different scrubber chemistry – The Endicott wet FGD system is limestone-based with *in situ* forced oxidation; the Zimmer wet FGD system is Thiosorbic® Lime-based with natural oxidation in the scrubber and *ex situ* forced oxidation system for gypsum production. With Thiosorbic® Lime-based systems, the liquid-to-gas ratio in the wet scrubber is also much lower than a limestone system, 21 to 78 respectively; work performed at MTI during the Advanced Emissions Control Development Program showed a slight decrease in mercury removal performance across the scrubber with decreasing L/G ratio¹. Prior to the Zimmer demonstration, all testing conducted with the control technology had been on limestone-based, forced oxidation systems. It was theorized that the different SO₂ control chemistry associated with the Thiosorbic® Lime-based system would not impact mercury control performance. However, this was not the case. The most noticeable effect attributable to this difference is the lack of suppressed mercury reemission that was observed during the Zimmer tests.

In Figure 3.3-15 the outlet elemental mercury concentration measurements for all of the tests conducted during this program are shown as a function of inlet elemental mercury concentration. Also included are the measurement results for the pilot development work conducted at MTI. The open symbols represent the baseline tests for each of the listed test programs. It is readily apparent that the control technology had no impact on mercury reemission during the Zimmer tests; every test showed greater elemental mercury concentrations at the outlet versus the inlet. It is also apparent that there would have been reemission in the Pilot Program and at Endicott if the reagent was not used as shown by the baseline data.

¹ Advanced Emissions Control Development Program – Phase II Final Report, Revision 1 USDOE Contract No. DE-FC22-94PC94251

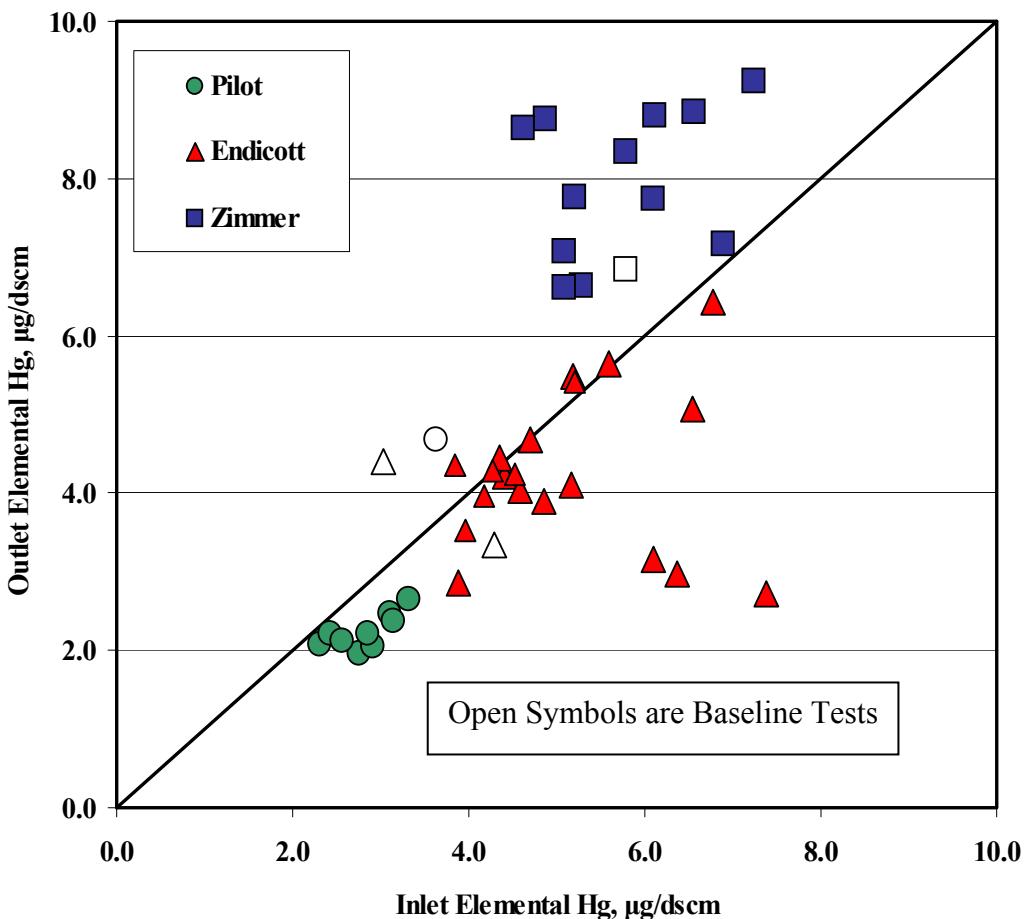


Figure 3.3-15: Outlet Elemental Mercury Concentration as a Function of Inlet Elemental Mercury Concentration – Pilot, Endicott, and Zimmer

The effect this had on total mercury removal across the wet FGD system, compared to the Endicott and pilot tests, is shown in Figure 3.3-16. In the figure, the oxidized, elemental and total wet FGD mercury removal results are shown for two pilot test programs, Endicott and Zimmer. The left side of the graph shows the removal performance for the baseline tests; the right side shows the average performance for the reagent tests. By comparing the baseline and reagent tests for both the pilot and Endicott test programs, a marked increase in total mercury removal across the scrubber is achieved when the reagent is added to the wet FGD system. Conversely, the ineffectiveness of the reagent in the Zimmer wet FGD system results in a much lower total removal across the scrubber, even though oxidized removal across the scrubber remained high.

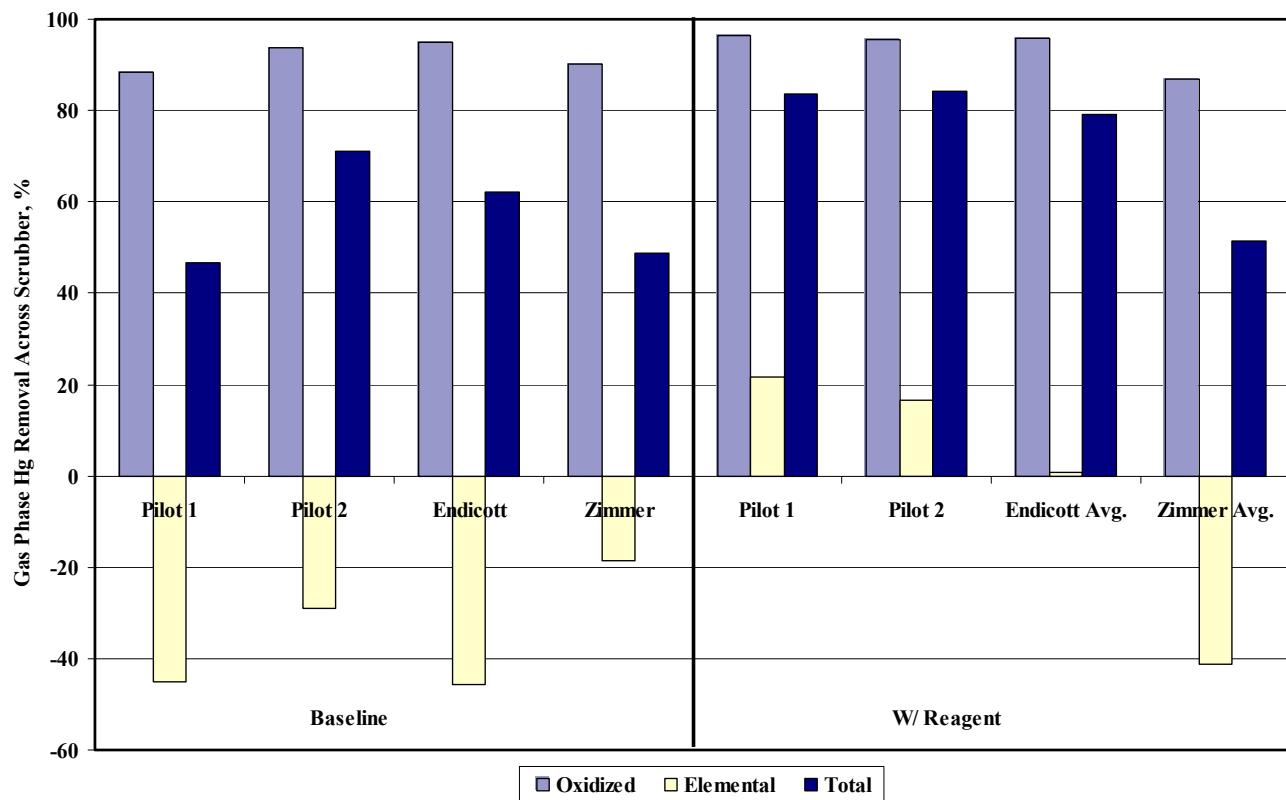


Figure 3.3-16: Speciated Mercury Removal Performance, Baseline and w/ Reagent

3.3.3 Ontario Hydro Flue Gas Sampling Summary and Conclusions

Full-scale field demonstration testing was performed at two power plants to evaluate B&W/MTI's advanced mercury control technology. The Ontario Hydro flue gas sampling method, designed to determine mercury speciation in the flue gas, was used to measure mercury concentration in the flue gas at the inlet and outlet of the wet FGD systems at both plants.

Parametric tests, intended to establish feed rate/performance curves, were performed at MSCPAs Endicott station. Based on the results of the Parametric tests, Verification and Long-Term tests were conducted to determine the reliability of mercury removal performance and the impact on plant operation and SO₂ removal performance. Average mercury removal across the wet FGD system during the Verification and Long-Term tests ranged from 76% to 79%. Most of the oxidized mercury present in the flue gas was removed in the wet FGD system and there was no increase in elemental mercury concentration at the scrubber outlet, indicating that the control technology was successful in not only maintaining high oxidized mercury removal but simultaneously suppressing elemental mercury reemission.

Following the Endicott test program, two weeks of Verification tests were performed at Cinergy's Zimmer station. Average mercury removal across the wet FGD system during these tests averaged 51%. Compared to the Endicott results, lower oxidized mercury removal performance was observed at Zimmer (87% vs. 96%). In addition, elemental mercury concentrations increased across the wet FGD system, indicating that the control technology was not effective in suppressing the reemission of captured mercury from the scrubber. Testing conducted with 50% more reagent feed at the end of the Zimmer test program showed no improvement in mercury removal performance.

At both power plants, the wet FGD systems were very effective in removing oxidized mercury from the flue gas entering the scrubber. Total wet FGD mercury removal performance, however, was limited by the amount of elemental mercury present in the inlet flue gas. As discussed in the next section, a comparison of various technical scenarios illustrates the importance of a viable mercury oxidation technology in obtaining high total mercury removals in wet FGD systems.

3.4 A CASE FOR OXIDATION TECHNOLOGIES

Based on the data presented in the previous sections, it is apparent that some type of elemental mercury oxidation (or capture) technology is necessary to achieve total wet FGD mercury removals at or above 90%. During the Endicott Verification and Long-Term tests, for example, 94 to 96% of the oxidized mercury entering the wet FGD system was successfully captured. Even with the control technology effectively suppressing mercury reemission, average mercury removal across the wet FGD system was 76 to 79%. This performance can be directly attributed to the mercury speciation percentages of the inlet flue gas (73 to 82% oxidized, 18 to 27% elemental). Figure 3.4-1 shows mercury speciation in the vapor phase for typical Ohio coals. Figure 3.4-2 shows the Cl/Hg ratio for typical Ohio coals.

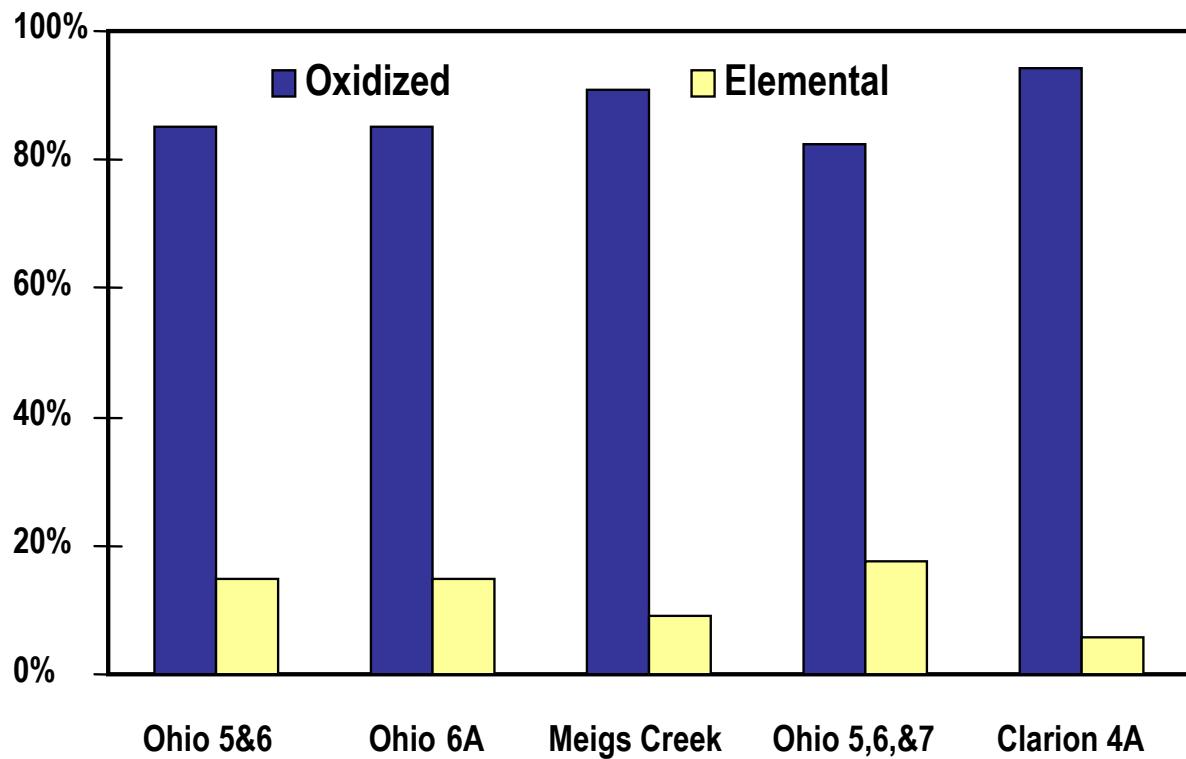


Figure 3.4-1: Mercury Speciation for Typical Ohio Coals

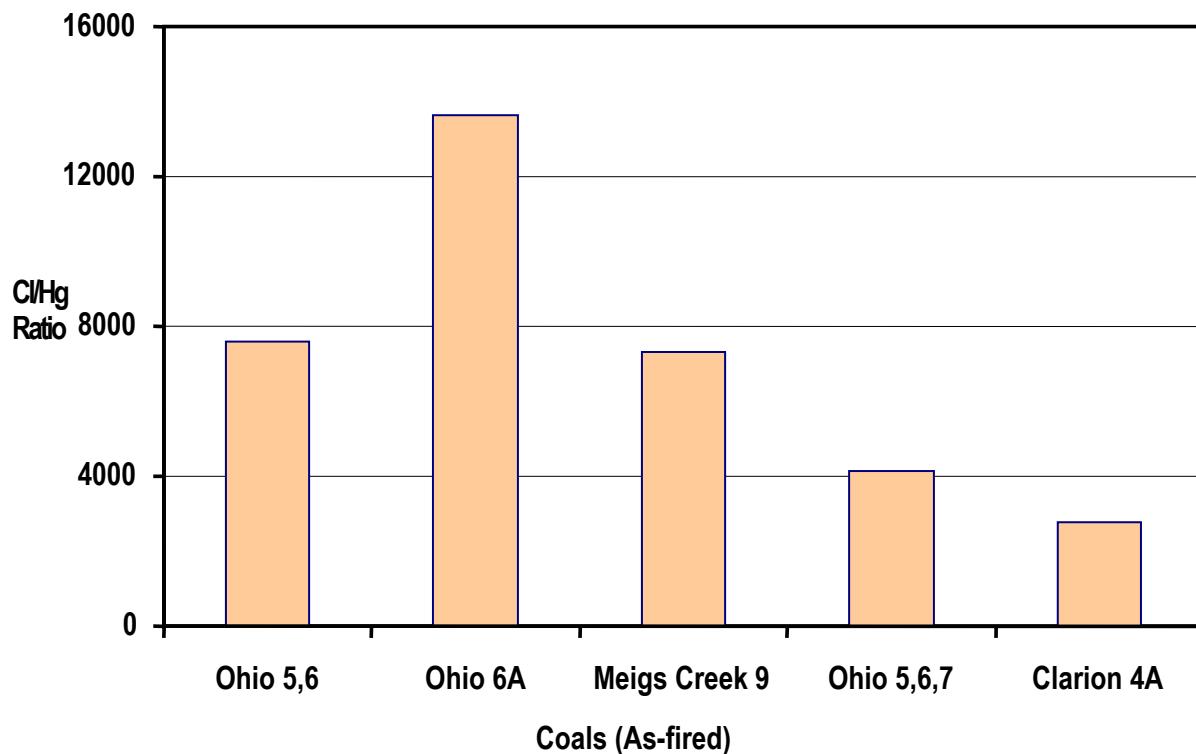


Figure 3.4-2: Range of Chlorine Content for Typical Ohio Coals

The potential increase in total wet FGD mercury removal performance offered by the availability of an effective elemental mercury oxidation technology is shown in Figure 3.4-3. In the figure, four sets of wet FGD inlet and outlet gas phase mercury speciation bars are shown:

- Baseline – this condition represents a “typical” bituminous-fired, limestone-based, forced oxidation wet FGD system. For this scenario, a mercury speciation ratio of 75% oxidized, 25% elemental was chosen. An oxidized removal performance of 95% was also assumed, as was the rate of elemental mercury reemission, based on the Endicott baseline data.
- Enhanced Current – Applies the control technology evaluated during this program to the Baseline case.
- Baseline w/ Oxidation Technology – Applies *only* an oxidation technology capable of producing a flue gas with 95% of the mercury in the oxidized form.
- Enhanced w/ Oxidation Technology – Applies the control technology evaluated during this program *in addition to* the oxidation technology scenario described above.

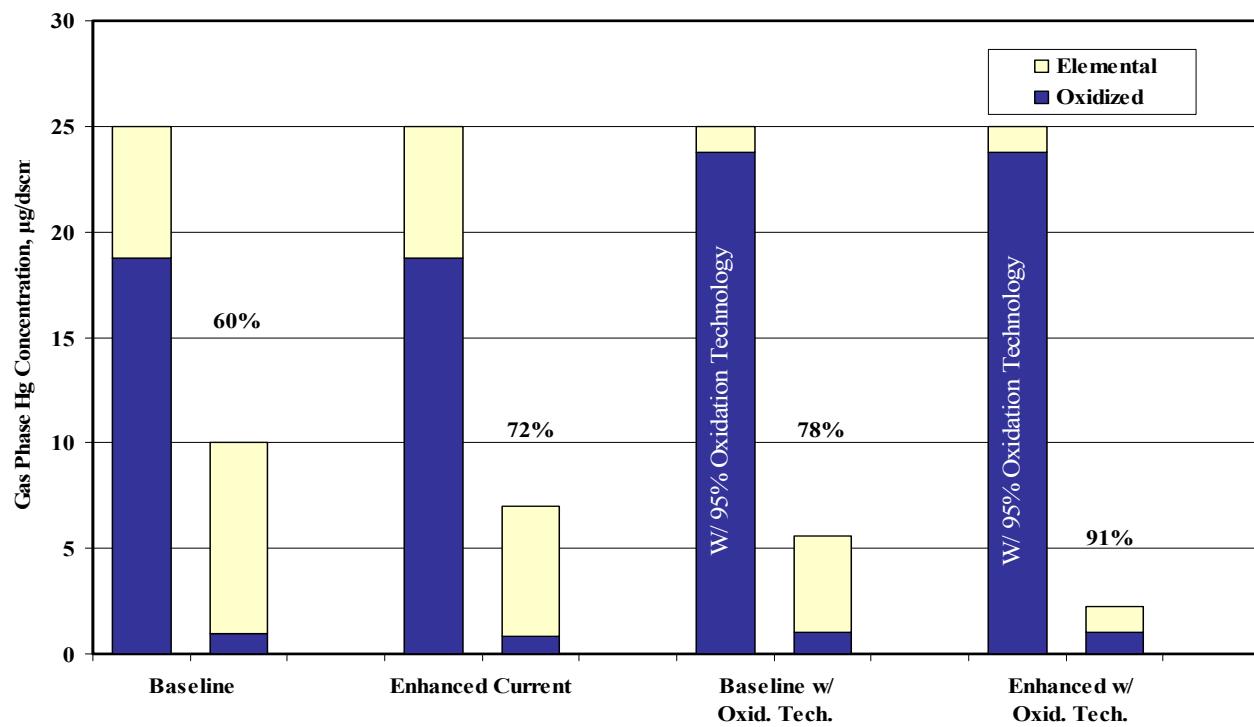


Figure 3.4-3: Comparison of Mercury Control Scenarios

For the first two scenarios, the application of B&W/MTI’s control technology improves total mercury removal across the scrubber (from 60% to 72%) by preventing the reemission of captured mercury from the scrubber. Similarly, by applying an oxidation technology (bar set 3), total mercury removal across the scrubber can be improved (from 60% to 78%) by increasing the

percentage of oxidized mercury, thereby making more of the mercury available for absorption in the wet FGD system. However, some of the captured mercury is still reemitted from the scrubber, limiting the overall removal performance. By applying both technologies, high overall removals are attained by simultaneously providing a high oxidized content flue gas to the wet FGD system and preventing any of the captured mercury from leaving the system as elemental mercury.

Two promising examples of oxidation technologies are chloride addition and use of a SCR. Testing of these technologies was not completed as part of this project, but information supporting their development is provided below.

Chloride Addition. One potential oxidation technology is chloride addition. B&W's approach to chloride addition is based on licensed technology developed and patented⁶ by Niro, A/S, in the early 1990's. The impact of chloride addition on the speciation of mercury was investigated⁷ during the firing of a western U.S. coal in B&W's 100 million Btu/hr CEDF as part of a U.S. DOE/B&W funded project entitled, "Cost-Effective Control of NO_x with Integrated Ultra Low-NO_x Burners and SNCR". A chloride-containing solution was sprayed directly into the flame zone of the furnace. Table 3.4-1 summarizes the chloride content of the coal, the chloride added to the combustion zone, and the results of sampling used to determine the chlorine content of the flue gas at the inlet of the ESP. The predicted chlorine concentration based on the coal analysis and flow rate of additive is greater than the measured chlorine concentration in the flue gas, but the difference is relatively small.

Test	Coal Chlorine		Added Chlorine	Total Chlorine	Gas-Phase Chlorine
	(ppm)	(lb/hr) ¹	(lb/hr)	(lb/hr)	(lb/hr) ²
Baseline	64.5	0.53	0.00	0.53	0.27
Cl Addition	69.1	0.56	5.06	5.62	5.01

1 - Based on a coal flow rate of 8150 lb/hr

2 - Based on flue gas flow rate and measured Cl concentration (EPA Method 26A)

Table 3.4-1: Chloride Addition Test Conditions

Triplicate sets of Ontario Hydro measurements were conducted at the inlet to the ESP at a temperature of 320 °F. Figure 3.4-4 summarizes the average mercury speciation results for the baseline and chloride addition tests. Elemental mercury in the flue gas decreases with the addition of chloride, while the oxidized mercury increases. Particulate-phase mercury shows a small increase with chloride addition.

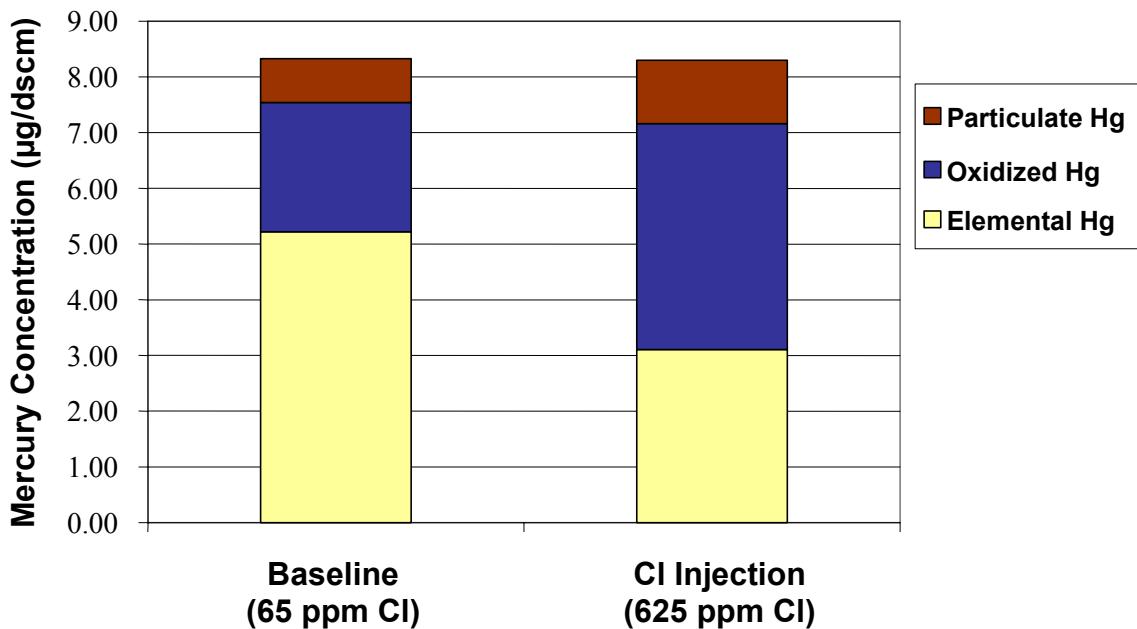


Figure 3.4-4: Impact of Chloride Addition on Mercury Speciation

The addition of chloride to the combustion zone clearly enhances the formation of oxidized mercury. The amount of chloride added in this test was relatively modest, equivalent to a coal chloride content of about 625 ppm (0.0625%).

SCR. SCR systems are another potential way to enhance mercury oxidation. Normally, SCR catalysts are used for reducing NO_x with ammonia. However, all reduction reactions also involve oxidation. For example, although the NO_x present in the flue gas is reduced in the SCR process, the NH_3 is oxidized. Also, it has long been recognized that conventional SCR catalysts have a tendency to oxidize SO_2 to SO_3 . In order to evaluate⁸ the effect an SCR catalyst would have on Hg speciation, a prototype “catalyst device” was designed and fabricated to simulate a full-scale SCR reactor on a coal-fired boiler during an OCDO/B&W project entitled, “Mercury Control for Coal-Fired Boilers”.

Testing was conducted in B&W’s Small Boiler Simulator (SBS) facility. The SBS was fired with Mahoning 7 coal. Mercury speciation results are presented in Figure 3.4-5. Each bar shown in the figure represents a single Ontario Hydro sample train, and is identified either as an “SCR” train (flue gas has contacted the SCR panels in the catalyst device) or a “Reference” train (flue gas is untreated). From left to right, each SCR/Reference pair of bars represents a simultaneous pair of Ontario Hydro sample trains. Each bar is divided to show the amount of oxidized and elemental mercury present in the flue gas. The numerical value above each bar represents the percentage of gas phase mercury existing in the oxidized form.

It can be seen from the data that substantial mercury oxidation was achieved across the SCR catalyst. For the 3 sets of parallel Ontario Hydro sample trains the average percent oxidized

mercury present increased from 50.9% untreated to 93.4% in the presence of the SCR catalyst. In addition, for each SCR/Reference bar set, the total mercury present is similar indicating that the gas-phase mercury is remaining in the gas phase (and not, for example, adsorbing onto the catalyst surface). Particulate mercury concentrations were determined for one test. Less than 2% of the mercury present in the flue gas (0.05 $\mu\text{g}/\text{dscm}$ and 0.34 $\mu\text{g}/\text{dscm}$ in the Reference and SCR trains, respectively) was in the particulate phase and not included in Figure 3.4-5.

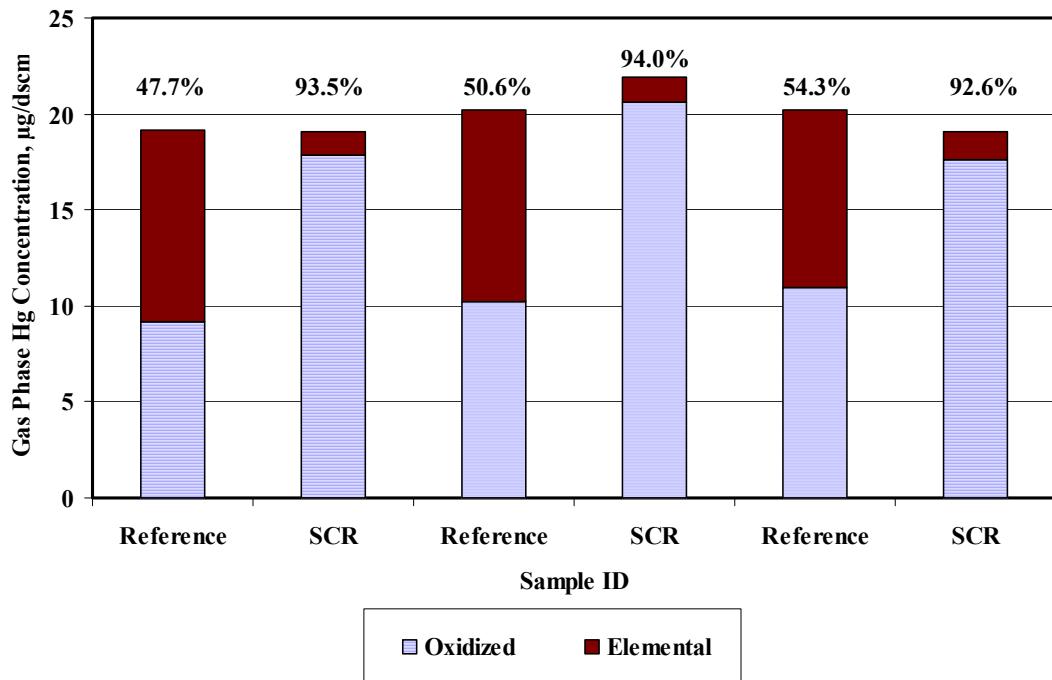


Figure 3.4-5: Effect of SCR Catalyst on Mercury Speciation

Oxidation technology cost impact. The cost impact of adding an oxidation technology to B&W/MTI's enhanced wet FGD mercury removal technology is expected to be very small in the case of adding chlorides to the power plant system. Adding chloride directly onto the coal means only a minor addition of a system to add chloride to the coal feeder belt upstream of the pulverizer. Also, the cost of the chlorides themselves is very inexpensive.

The cost impact of using an SCR for oxidation is free in the case where an SCR is already available on a unit for NOx control, therefore there is no cost impact on the B&W/MTI enhanced wet FGD mercury removal technology. If an SCR would be added specifically for mercury control, there would be an impact on the cost of the B&W/MTI enhanced wet FGD mercury removal technology. To what extent was not calculated as part of the economics completed with this project because the mercury oxidation work was completed independently of this project.

3.5 MERCURY IN COAL UTILIZATION BY-PRODUCTS (CUBs)

The objective of this task is to study the fate of mercury (Hg) contained in Coal Utilization By-Products (CUB) obtained from the Zimmer and Endicott Stations during this project.

Previous research has shown that the mercury released during coal combustion can exit the plant in three ways. It can condense or react with the fly ash, be absorbed in subsequent flue gas desulfurization (FGD) processes, or remain in the gas and exit the stack. This section will explore the differences in the two plants and how they affect the distribution and stability of the Hg in the CUBs.

This section is divided into three parts. The first, presents the results of conventional analytical techniques performed on the various samples from the two sites including ultimate coal analyses and Cold Vapor Atomic Absorption (CVAA) to measure the total mercury in a sample. The second, presents the results of Thermal Dissociation Tests (TDT), known as Thermal Decomposition in previous reports. This test was developed by MTI and involves measuring the temperature at which mercury compounds are evolved from a sample. It is an extension of the work reported in the Final Report for a project entitled *Mercury Control for Coal-Fired Utilities* that was completed August 31, 2001¹. This project was funded in part by the Ohio Coal Development Office, Department of Development, State of Ohio. The third, presents the results of a mercury material balance for the two plants.

3.5.1 Conventional Chemical Analyses

This section presents the results of conventional analytical techniques on coal and CUB samples. The main procedure used was EPA Method SW846-7471A. This method involves an aggressive digestion to dissolve all the mercury compounds, followed by CVAA analyses to determine the total mercury in the sample. It should be noted that no TCLP tests were performed because all tests to date indicate the mercury in CUB is not leachable.

Table 3.5-1 summarizes the sample preparation techniques and Table 3.5-2 summarizes the analytical methods used for mercury determination.

Table 3.5-1: Process Stream Sample Preparation Techniques for Mercury Analysis

Matrix	Preparation Technique	Method Reference
Coal	Oxygen Bomb	ASTM D3684-78
Ash/Slurry/Sludge	Acid Digestion	EPA 7471A
Liquid Streams	Acid Digestion	EPA 3015

Table 3.5-2: Process Stream Analytical Methods

Matrix	Analytical Method	Method Reference
Coal	CVAAS ASTM D3684-78	Standard Method for Total Mercury in Coal by Oxygen Bomb/Cold Vapor Atomic Absorption Spectroscopy
Ash/Slurry/Sludge	CVAAS SW7471/SW846	Mercury in Solids or Semi Solids Waste/Cold Vapor Atomic Absorption Spectroscopy
Liquid Streams	CVAAS	Cold Vapor Atomic Absorption Spectroscopy

3.5.1.1 Endicott Stream Sampling

Stream samples from the field tests at Zimmer and Endicott were collected for each test condition. Samples are divided into three types, Feed Streams, Intermediate Streams and Waste Streams. At Endicott, there are three effluent streams (waste ash, gypsum and treated water), three feed streams (coal, Hg reagent and limestone), and three intermediate streams (ESP ash, wet FGD slurry and water treatment sludge). All samples were collected in 500-ml Nalgene bottles.

Coal. Plant personnel take coal samples from the pulverizer feeders every hour. These samples are combined and riffled to produce a weekly average coal sample. A representative hourly sample was collected for each OH test and the weekly samples were also saved. An ultimate analysis, including chlorine and mercury, was performed on select samples. Figure 3.5-1 shows the coal sampling apparatus.

Hg Reagent. The proprietary mercury removal reagent was delivered via tanker, Figure 3.5-2, in a very dilute form. At Endicott, one truck was sufficient for the entire test. Samples were collected on a weekly basis during the parametric and validation tests and on a bimonthly basis during the long-term test.

ESP Ash. B&W/MTI's mercury control technology has no impact on the ESP. However, samples were collected from each of the four ESP fields for each test condition to provide information for a mercury inventory. Select samples were analyzed for total mercury and TDT characteristics. Figures 3.5-3 and 3.5-4 show the hopper arrangement and the sampling location. Only one row was sampled, Hoppers 12-9. Gas flow is from right to left in the diagram, so Hopper 12 represents ESP Field 1 and Hopper 9 represents ESP Field 4. Field 4 rarely contained ash.

Waste Ash. Waste ash is collected in an ash silo and mixed with water through a pug mill, shown in Figure 3.5-5, for dust control before loading into a truck for disposal. The silo contains all of the dry ash streams from the plant including ash from the airheater and economizer ash

hoppers. It is normally emptied twice per day. One sample was collected each test day. Select samples were analyzed for total mercury and TDT characteristics.

Limestone Slurry. A limestone slurry sample was taken once per day during testing from the storage tank recirculation and feed pumps shown in Figure 3.5-6. At Endicott, limestone is fed to the scrubber batch-wise to keep pH and SO₂ removal within appropriate ranges. Select samples were analyzed for total mercury in the liquid and solid fractions.

Water Treatment Sludge. Endicott has a multistage water treatment plant that is used to purify wastewater before it is discharged. One step in the process uses a lime-rich by-product from a local municipal water treatment plant to adjust the pH of the stream. Thickened sludge from this step, shown in Figure 3.5-7, is fed back to the wet scrubber to utilize the excess lime in the solids and may be a source for mercury to enter the system. Therefore, a daily sample was collected from the line leading back to the scrubber shown in Figure 3.5-8. Select samples were analyzed for total mercury in the liquid and solid fractions and for TDT characteristics.

Treated Water. A treated water sample was drawn from the final treatment tank for each test condition as shown in Figure 3.5-9. Select samples were analyzed for total mercury.

Wet FGD Slurry. Figure 3.5-10 shows the sample port on the side of the absorber recirculation tank used to collect wet FGD slurry samples. A sample was collected near the completion of each OH Test. Select samples were analyzed for total mercury in the liquid and solid fractions and for TDT characteristics.

Gypsum. A gypsum sample was collected for each test condition. Samples were taken directly from the filter drum, Figure 3.5-11, or from the top and sides of the gypsum pile, Figure 3.5-12, if the filter was not operating. Select samples were analyzed for total mercury in the liquid and solid fractions and for TDT characteristics.



Figure 3.5-1: Endicott Coal Sampling Device and Pulverizer Feeder Sampling Port



Figure 3.5-2: Mercury Removal Reagent Tanker at Endicott

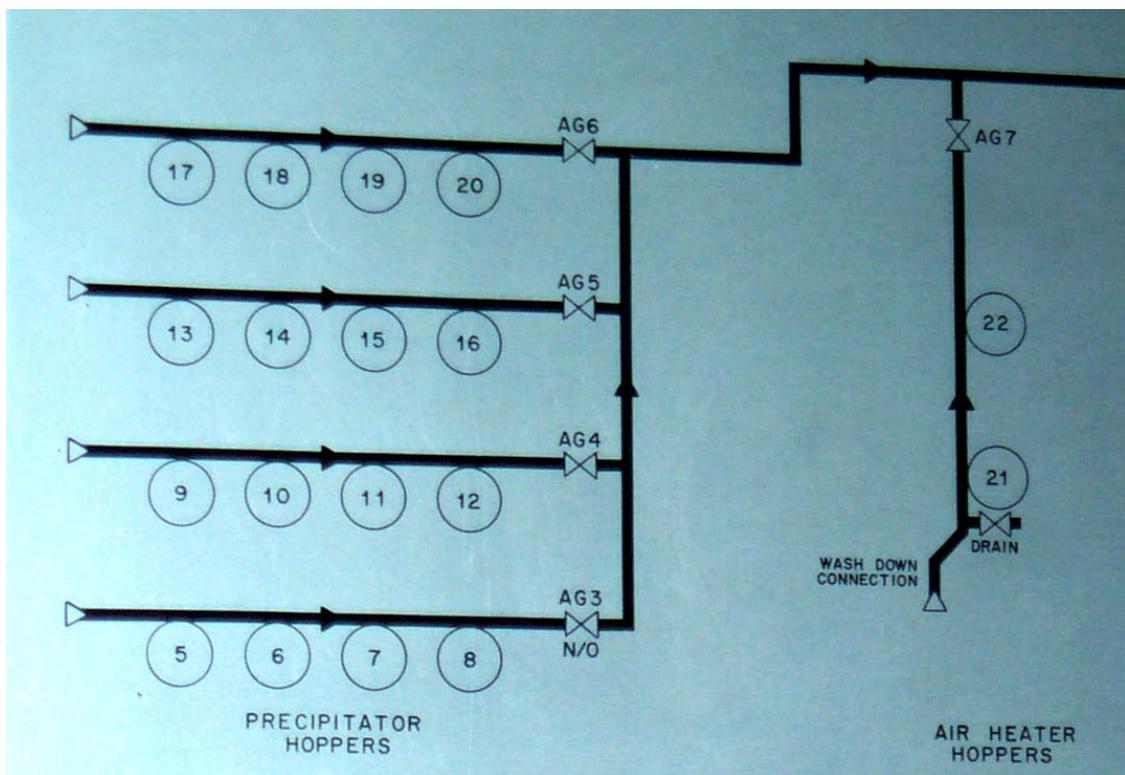


Figure 3.5-3: ESP Hoppers at Endicott

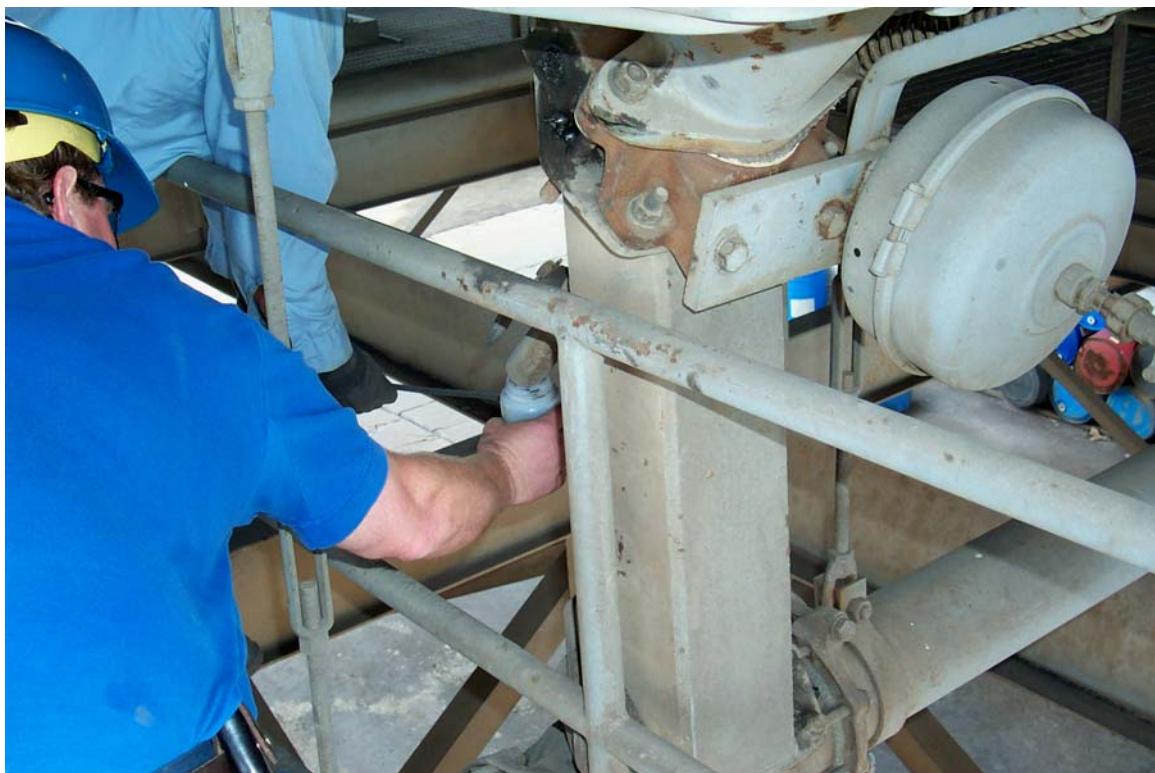


Figure 3.5-4: ESP Ash Sampling at Endicott

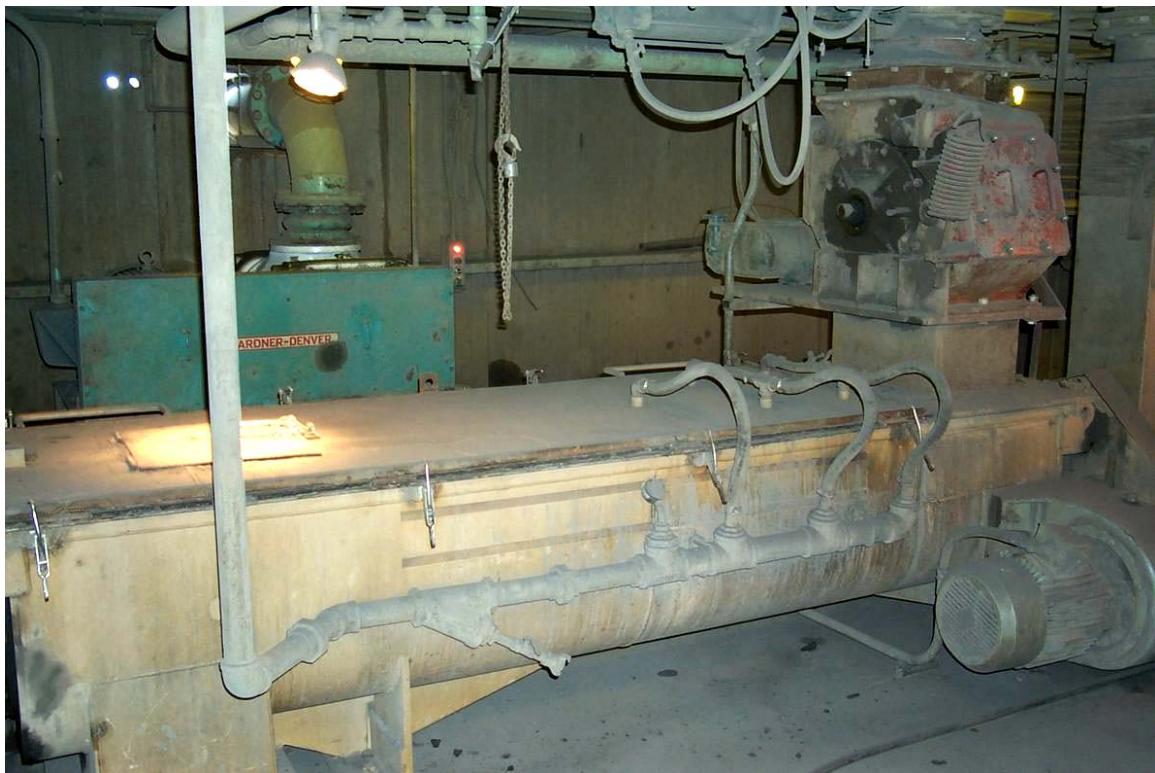


Figure 3.5-5: Pug Mill on the Waste Ash Silo at Endicott



Figure 3.5-6: Limestone Slurry Pump and Storage Tank at Endicott



Figure 3.5-7: Settled Sludge in a Tank in the Water Treatment Process at Endicott



Figure 3.5-8: Sample Point for the Water Treatment Sludge at Endicott



Figure 3.5-9: Treated Water Overflow Weir at Endicott



Figure 3.5-10: Wet FGD Slurry Sample Tap on the Absorber Recirculating Tank at Endicott



Figure 3.5-11: Gypsum Filter Drum at Endicott



Figure 3.5-12: Gypsum Filter Pile at Endicott

3.5.1.2 Zimmer Stream Sampling

Zimmer has four effluent streams (Fly Ash, Gypsum, Fines and Centrate Water), four feed streams (Coal, Hg Reagent, Make-up Water and Thiosorbic Lime), and two intermediate streams (ESP Ash and Wet FGD Slurry). All samples were collected in 500-ml Nalgene bottles.

Coal. Plant personnel collected a coal sample from every barge emptied during the 15-day test. Proximate analyses were done on these samples. However, the samples were mistakenly discarded before analyses for chlorine and mercury were done. Fortunately, several samples were retained for ash fusion analyses by Cinergy and these samples were analyzed for chlorine and mercury. Only four samples from the fifteen day test were retained.

Hg Reagent. The proprietary mercury removal reagent was delivered in tankers in a dilute form. At Zimmer, two trucks were used during the test. Several samples from each tanker were collected.

Thiosorbic Lime Slurry. A feed slurry sample was taken each day from the slurry feed tanks as shown in Figure 3.5-13. Select samples were analyzed for total mercury in the liquid and solid fractions.

Reclaim Water. Additional water is used in the scrubber process for several purposes. A sample of this water was taken once a day as shown in Figure 3.5-14. Select samples were analyzed for total mercury.

ESP Ash. Figure 3.5-15 is a diagram of the hopper arrangement at Zimmer. There are two identical ESP modules, East (Box 2) and West (Box 1), and each module has five fields and eight rows of hoppers as indicated by the cell numbers in the figure. Gas enters the ESP from a duct running between the modules, exits on the far sides, and recombines before entering the wet scrubbers. Hoppers that were sampled are highlighted. Field 5 rarely contained enough ash for a sample. Ash samples were collected daily from each hopper as shown in Figure 3.5-16. Select samples were analyzed for total mercury and for TDT characteristics.

Waste Ash. Waste ash is collected in an ash silos for disposal. Typically, low carbon ash is collected and stored separately from high carbon ash. The low carbon ash is stored in the south silo and is loaded into tankers for sale as shown in Figure 3.5-17. One set of samples were collected each day. Select samples were analyzed for total mercury and for TDT characteristics.

Wet FGD Slurry. A composite slurry sample was collected from the sample taps on the module recirculation slurry slipstream for pH control for each operating module during each OH Test. Figure 3.5-18 shows a slurry sample being taken at one such sample location. Select samples were analyzed for total mercury in the liquid and solid fractions and for TDT characteristics.

Slurry Fines and Centrate Water. Gypsum from the *ex situ* oxidation system is dewatered in a multistage process that involves a hydroclone followed by a filter belt. Hydroclone underflow goes to the filter belt and is dewatered to make salable gypsum. Hydroclone overflow, containing process fines, is sent to a thickener. The thickener underflow is then sent to

centrifuges to separate the fines from the process water. The fines, Figure 3.5-19, are trucked to the landfill and the centrate water, Figure 3.5-20, is discharged to a sludge pond. These streams were sampled every day. Select samples were analyzed for total mercury and for TDT characteristics

Gypsum. A gypsum sample was collected each day from the vacuum filter belts. Select samples were analyzed for total mercury and for TDT characteristics. During the last few days of testing (Tests 41-44), the *ex situ* oxidation system was shut down for repairs. During this time, spent wet FGD slurry was sent, unoxidized, to thickeners and then to a set of drum filters, where samples were taken. Figure 3.5-21 shows the gypsum pile and fines centrifuges at Zimmer.



Figure 3.5-13: Thiosorbic Lime Slurry flowing from Storage Tanks at Zimmer

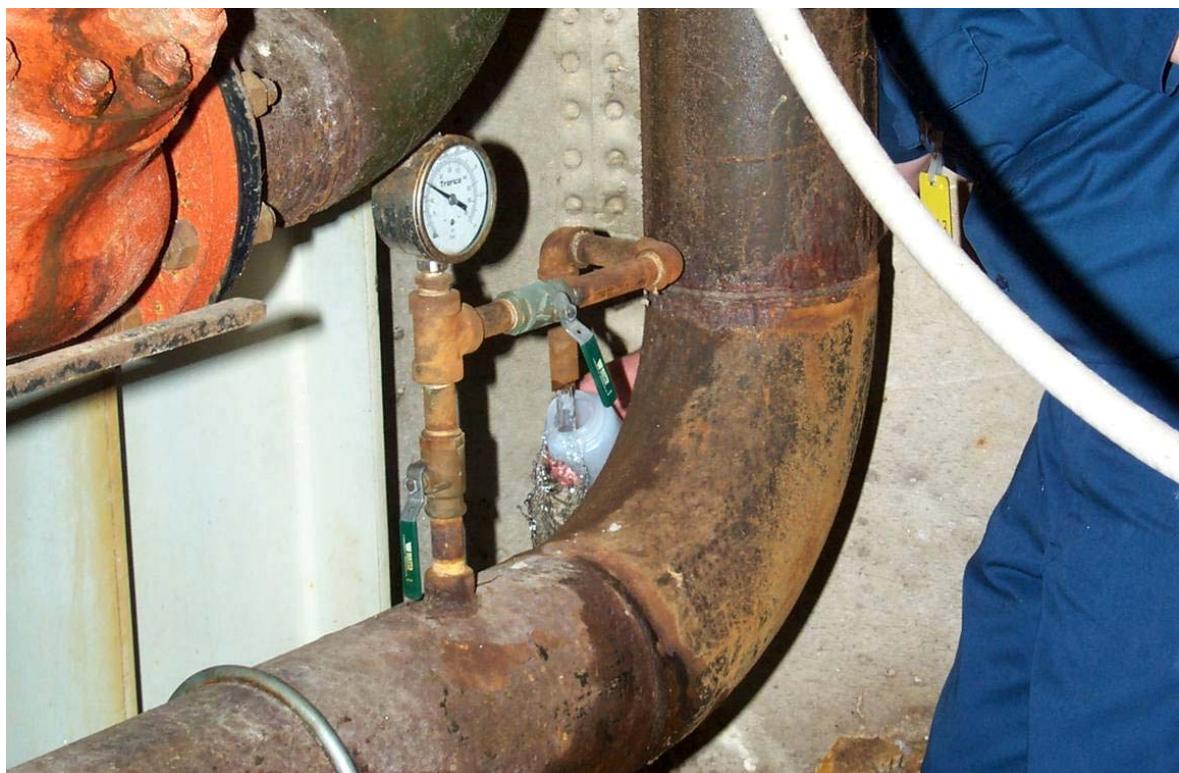


Figure 3.5-14: Reclaim Water Sampling in the Scrubber Building at Zimmer

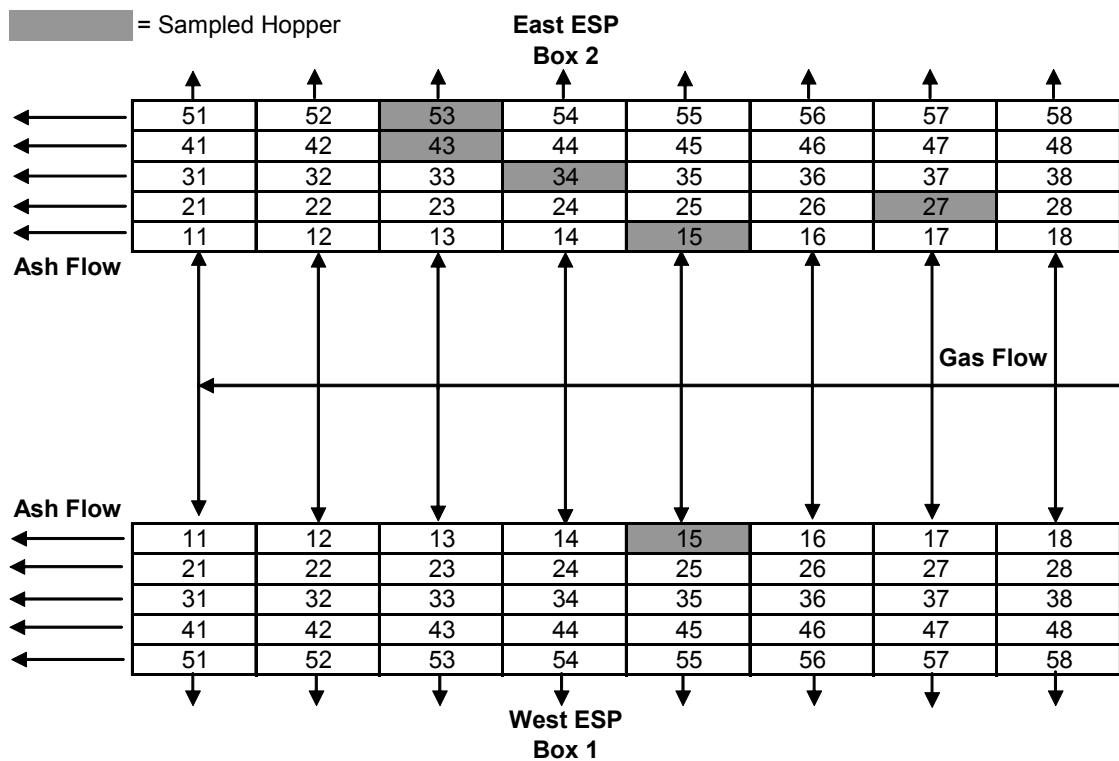


Figure 3.5-15: ESP Hopper Layout at Zimmer



Figure 3.5-16: ESP Ash Sampling at Zimmer



Figure 3.5-17: Ash from the South Ash Silo being Loaded into a Tanker at Zimmer



Figure 3.5-18: Wet FGD Slurry Sampling at Zimmer



Figure 3.5-19: Wet FGD Slurry Fines from the Centrifuges at Zimmer

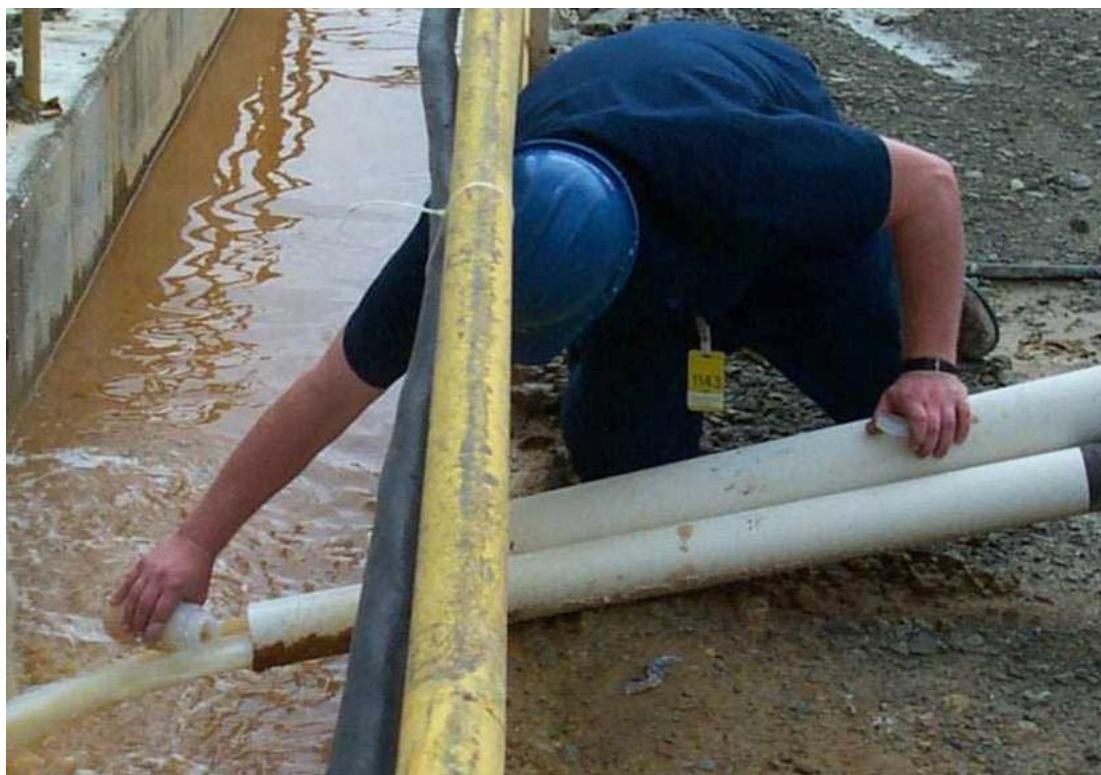


Figure 3.5-20: Centrate Water from the Centrifuges at Zimmer



Figure 3.5-21: Gypsum Pile (left, white) and Centrifuges (center, blue) at Zimmer

Tables 3.5-3 and 3.5-4 list all the process stream samples that were taken at Endicott and Zimmer, respectively. Lightly shaded cells represent the samples for which conventional chemical analyses were performed. The darkly shaded cells represent the samples for which TDT were performed. Tests for which all the samples were analyzed were chosen to represent a baseline condition and steady state condition with reagent. The tables also show the reagent flow rate for each test and the ID given to corresponding OH tests.

Table 3.5-3: Samples Collected and Analyzed from Endicott

Test	O-H Test ID	Waste			Feed			Intermediate					
		Waste Ash	Gypsum	Treated Water	Coal	Hg Reagent	Limestone Slurry	ESP Ash Field #1	ESP Ash Field #2	ESP Ash Field #3	ESP Ash Field #4	WFGD Slurry	WT Sludge
Raw Coal					XXXXX								
5/8/2001 Baseline	1A	X	X	X	X		X	X	X	X	X	X	X
	1B	X	X		X							X	
	1C				X			X	X	X	X	X	
	1D	X	X	X	X		X					X	
	2A	X	X	X	X	X	X	X	X	X		X	X
	2AO	X						X	X	X			
	2B				X							X	
	3A				X		X				X	X	
0.29 gph	3B	X	X	X	X			X	X	X		X	X
	3C				X							X	
	4A				X							X	
	4B	X	X	X	X			X	X	X	X	X	X
	4C				X	X						X	
	5A				X							X	
	5B	X	X	X	X			X	X	X	X	X	X
	5C				X							X	
0.08 gph	6A				X							X	
	6B	X	X	X	X			X	X	X		X	X
	7A				X							X	
	7B	X	X	X	X	X	X	X	X	X	X	X	X
	7C				X							X	
	8A				X							X	
	8B	X	X	X	X			X	X	X	X	X	X
	8C				X							X	
Validation	9A	X	X	X	X	X	X	X	X	X	X	X	X
	10A	X	X	X	X			X	X	X	X	X	X
	11A	X	X	X	X			X	X	X	X	X	X
	12A	X	X	X	X			X	X	X		X	X
	13A	X	X	X	X			X	X	X	X	X	X
	14A	X	X	X	X			X	X	X	X	X	X
	15A	X	X	X	X			X	X	X		X	X
	16A	X	X	X	X			X	X	X	X	X	X
	17A	X	X	X	X	X		X	X	X		X	X
	18A	X	X	X	X			X	X	X		X	X
	19A	X	X	X	X			X	X	X	X	X	X
	20A	X	X	X	X			X	X	X	X	X	X
	21A	X	X	X	X			X	X	X	X	X	X
	22A	X	X	X	X			X	X	X	X	X	X
Long Term	23A				X								X
	23B	X	X		X	X	X	X	X	X	X	X	X
	23C				X							X	
	24A				X							X	
	24B	X	X	X	X	X	X	X	X	X	X	X	X
	24C				X							X	
	25A				X							X	
	25B	X	X	X	X	X	X	X	X	X	X	X	X
	25C				X							X	
	26A				X							X	
	26B	X	X		X	X	X	X	X	X	X	X	X
	26C				X							X	
	27A				X							X	
	27B	X	X	X	X+pyrites	X	X	X	X	X	X	X+Fines	X
10/4/2001 Baseline	27C				X							X	
	28A				X							X	
	28B	X	X	X	X	X	X	X	X	X	X	X	X
	28C				X							X	
	29A				X							X	
	29B	X	X	X	X	X	X	X	X	X	X	X	X
	29C				X							X	
	30A				X							X	
Others	30B	X	X	X	X			X	X	X	X	X	X
	30C				X							X	
	30D												
	30D				Nist Standard Coal								
					Thickener Underflow								
					Coal Pile Runpff								
					Coal Pile Runpff Sludge								


 Coal Ultimate Analyses and Hg by CVAA
 TDT

Table 3.5-4: Samples Collected and Analyzed from Zimmer

Test Reagent Flow	Waste Stream						Feed Stream	
	O-H Test ID	Waste Ash	Gypsum Filter Belt	Reclaim Water	Centrifuge Fines	Centrate Water	Coal	Hg Reagent
0.0 gph	31B		X	X	X	X	X	
27.2 gph	32A	X	X	X	X	X	X	X
	33A	X	X	X	X	X	X	
	34A	X	X	X	X	X	X	
	35A		X	X	X	X	X	
	36A		X	X	X	X	X	X
	37A	X	X	X	X	X	X+pyrites	
	38A	X	X	X	X	X	X	
	39A	X	X	X	X	X	X+pyrites	
	40A	X	X	X	X	X	X	
	41A			X			X	
	42A		X	X			X	
	43A	X		X			X+pyrites	
40 gph	44A	X	X	X			X+pyrites	X

Test Reagent Flow	Intermediate Stream							
	Lime Slurry	ESP Ash West 1-15	ESP Ash East 2-15	ESP Ash East 2-27	ESP Ash East 2-34	ESP Ash East 2-43	ESP Ash East 2-53	WFGD Slurry
0.0 gph	X	X	X	X				X
27.2 gph	X	X	X	X				X
	X	X	X	X				X
	X	X						X
	X	X	X	X				X
	X	X	X	X				X
	X	X	X	X				X
	X	X	X	X				X
	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X
40 gph	X	X?	X	X	X	X	X	X

 Coal Ultimate Analyses and Hg by CVAA
 TDT

3.5.1.3 Results of Conventional Chemical Analyses

Tables 3.5-5 and 3.5-6 show the results of the mercury analyses conducted on the samples from Endicott and Zimmer, respectively. The tables give the OH Tests ID, the sample type and the amount of mercury measured in the solid (on a dry basis) and liquid fractions of the sample. ND indicates that the mercury was below the detection limit for CVAA which was 0.0005 mg/l for liquid samples and 0.005-0.4 mg/kg for solid samples. The range in the detection limit for solid samples depended on sample size and mercury concentration. The detection limit was low (0.01 mg/kg) for samples containing little mercury, and high (0.4 mg/kg) for samples with high mercury concentrations. Duplicate runs are indicated by “Dup”.

Table 3.5-5: Results of Mercury Analyses on CUB Samples from Endicott

Test ID	Endicott Sample Type	Hg in Solid ppm-dry	Hg in Liquid mg/L	Test ID	Endicott Sample Type	Hg in Solid ppm-dry	Hg in Liquid mg/L
5B	ESP Ash Field 1	0.27		5B	Gypsum	1.15	
5B	ESP Ash Field 2	0.82		18A	Gypsum	0.95	
5B	ESP Ash Field 3	0.10		24B	Gypsum	0.61	
5B	ESP Ash Field 4	0.40		25B	Gypsum	0.58	
18A	ESP Ash Field 1	0.17		27B	Gypsum	0.74	
18A	ESP Ash Field 2	0.38		28B	Gypsum	0.48	
18A	ESP Ash Field 3	0.39		28B	Gypsum-Dup	0.56	
29B	ESP Ash Field 1	0.21		29B	Gypsum	0.62	
29B	ESP Ash Field 2	0.21		29B	Gypsum-Dup	0.62	
29B	ESP Ash Field 3	0.32		5B	WFGD Slurry	0.64	ND
29B	ESP Ash Field 4	0.30		9A	WFGD Slurry	0.91	ND
29B	ESP Ash Field 4-Dup	0.29		11A	WFGD Slurry	0.69	ND
5B	Waste Ash	0.22		13A	WFGD Slurry	0.75	ND
5B	Waste Ash-Dup	0.28		15A	WFGD Slurry	0.84	ND
18A	Waste Ash	0.23		18A	WFGD Slurry	0.87	ND
18A	Waste Ash-Dup	0.20		20A	WFGD Slurry	1.18	ND
29B	Waste Ash	0.11		22A	WFGD Slurry	0.52	ND
5B	Limestone Slurry	0.03	ND	29B	WFGD Slurry	0.46	ND
18A	Limestone Slurry	0.04	ND	29B	WFGD Slurry-Dup		ND
29B	Limestone Slurry	0.02	ND	5B	Treated Water		0.0010
5B	Water Treat. Sludge	1.31	ND	18A	Treated Water		ND
18A	Water Treat. Sludge	0.21	ND	24B	Treated Water		ND
29B	Water Treat. Sludge	0.33	ND	24B	Treated Water-Dup		ND
29B	Thickener Underflow	0.41	ND	25B	Treated Water		ND
29B	Coal Pile Run-Off		ND	27B	Treated Water		ND
29B	Coal Pile Run-Off Mud	0.04	ND	28B	Treated Water		ND
				29B	Treated Water		ND

ND = None Detected

Dup = Duplicate

Table 3.5-6: Results of Mercury Analyses on CUB Samples from Zimmer

Test ID	Zimmer Sample Type	Hg in Solid ppm-dry	Hg in Liquid mg/L	Test ID	Zimmer Sample Type	Hg in Solid ppm-dry	Hg in Liquid mg/L
31B	ESP Ash East 2-15	0.03		31B	Gypsum	0.04	
40A	ESP Ash East 2-15	ND		32A	Gypsum	0.06	
31B	ESP Ash East 2-27	0.04		34A	Gypsum	0.03	
40A	ESP Ash East 2-27	0.01		36A	Gypsum	0.05	
40A	ESP Ash East 2-34	ND		38A	Gypsum	0.06	
40A	ESP Ash East 2-43	ND		40A	Gypsum	0.10	
40A	ESP Ash East 2-53	0.06		31B	WFGD Slurry	0.40	ND
31B	ESP Ash West 1-15	0.01		32A	WFGD Slurry	0.42	ND
40A	ESP Ash West 1-15	0.01		32A	WFGD Slurry-Dup		ND
40A	Waste Ash	ND		34A	WFGD Slurry	0.44	ND
31B	Thiosorbic Lime	ND	0.0026	36A	WFGD Slurry	0.40	ND
40A	Thiosorbic Lime	ND	0.0030	38A	WFGD Slurry	0.33	ND
31B	Reclaim Water		ND	40A	WFGD Slurry	0.39	ND
32A	Reclaim Water		ND	42A	WFGD Slurry	0.93	ND
34A	Reclaim Water		ND	42A	WFGD Slurry-Dup	0.80	
36A	Reclaim Water		ND	44A	WFGD Slurry	0.31	ND
38A	Reclaim Water		0.0013	31B	Centrate Water	0.50	0.0018
40A	Reclaim Water		0.0011	32A	Centrate Water	0.28	ND
				32A	Centrate Water-Dup	0.24	
				34A	Centrate Water	0.08	0.0027
				36A	Centrate Water	0.03	0.0019
				38A	Centrate Water	0.07	0.0006
				40A	Centrate Water	1.30	0.0027
				40A	Centrate Water-Dup		0.0025
				31B	Centrifuge Fines	12.87	
				32A	Centrifuge Fines	14.49	
				34A	Centrifuge Fines	16.50	
				36A	Centrifuge Fines	13.38	
				38A	Centrifuge Fines	11.57	
				40A	Centrifuge Fines	11.11	

ND = None Detected

Dup = Duplicate

Figures 3.5-22 through 3.5-24 present a comparison of the mercury concentrations in the various sample streams from Endicott and Zimmer. Figure 3.5-22 shows ash mercury concentration as a function of ESP Field. Several things can be gleaned from the figure. First, there is very little mercury in the Zimmer Ash as compared to the Endicott Ash. Also, the mercury concentration in the various fields is not a strong function of the field, contrary to the notion that the mercury in fly ash is associated with the carbon and will, therefore, tend to concentrate in the latter fields with the fine soot and unburned carbon particles. One explanation for this is that the carbon content in the Endicott Ash was much higher than at Zimmer:

% Unburned Carbon	Field 1	Field 2	Field 3	Field 4
Endicott: Test 1A	12.1	12.3	6.9	4.2
Zimmer: Test 40A	0.4	1.9	1.2	1.0

Also, the unburned carbon content decreased in the latter fields at both sites. This would indicate that the unburned carbon is contained in a relatively coarse fraction of the ash or that most of the particulate was removed in the first few fields. This may have been the case because, at both sites, there was often little or no ash in the latter fields.

Figure 3.5-23 shows wet FGD slurry and gypsum mercury concentration as a function of test day for Endicott and Zimmer. For Endicott, the curves represent a test period of over 5 months. For Zimmer, the test period was 14 days. Several important aspects of the program are covered in the figure. First, the mercury in the slurry and gypsum solids from Endicott is higher than from Zimmer. This is consistent with the higher mercury concentration in the flue gas and the higher mercury removal measured at Endicott. The wide variation in the mercury concentration, especially at Endicott, is also consistent with the wide variation in mercury concentration measured in the flue gas and coal, and made it impossible to discern any increase in mercury concentration in the effluent due to the addition of the reagent. Also, it is important to note that the mercury concentration in the Endicott gypsum and slurry solids is about the same whereas, for Zimmer, the mercury in the slurry is much higher than in the gypsum. This means that there must be another means by which mercury can exit the system at Zimmer. As mentioned in the sampling section above, the fines in the slurry at Zimmer are concentrated and disposed separately. At Endicott, the slurry fines eventually build up to a point of equilibrium with what is collected on the filter cake of the filter drums. Figure 3.5-24 shows that the mercury concentration in the fines stream at Zimmer. The x-axis represents individual test days. The figure shows that the fines mercury was about 14 times higher than in the slurry. This is sufficient to account for the mercury concentration difference between the gypsum and slurry at Zimmer. It is further evidence that the mercury compound formed in the wet scrubber is associated with the fines and is not tied to the larger gypsum crystals. This theory was further tested during the Thermal Dissociation Tests, presented below. Early in the test program it was noticed that when slurry samples from Endicott were allowed to settle, the solids separated into a thick white layer, which settled out within minutes, and a thin dark layer that required about an hour to settle on top of the light layer (See Figure 3.5-35). When the dark layer was separated and tested, it was found to contain 50 times more mercury than the combined solids.

This is one of the most important findings of the test program because it suggests that the mercury in gypsum fines can easily be separated from the gypsum product by mechanical (hydroclones) or gravimetric (settling tanks) separation before resale. Since the mercury has been shown to be stable, the fines could then be dewatered and landfilled with other wastes. This is a positive finding for wet scrubber based mercury control technologies because it shows that, if necessary, the gypsum from these processes can be refined so that no significant secondary mercury releases are possible. Of course further testing at a wider variety of sites is needed before this can be concluded for all sites.

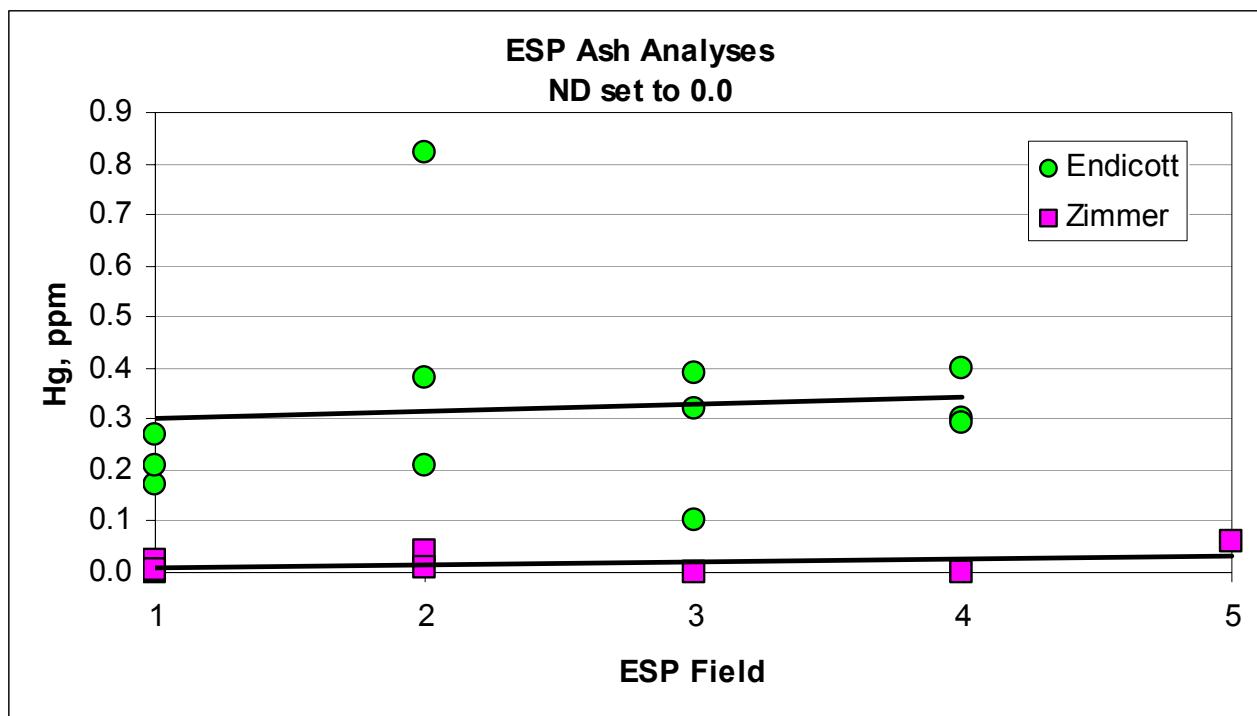


Figure 3.5-22: Mercury vs. ESP Field for Endicott and Zimmer

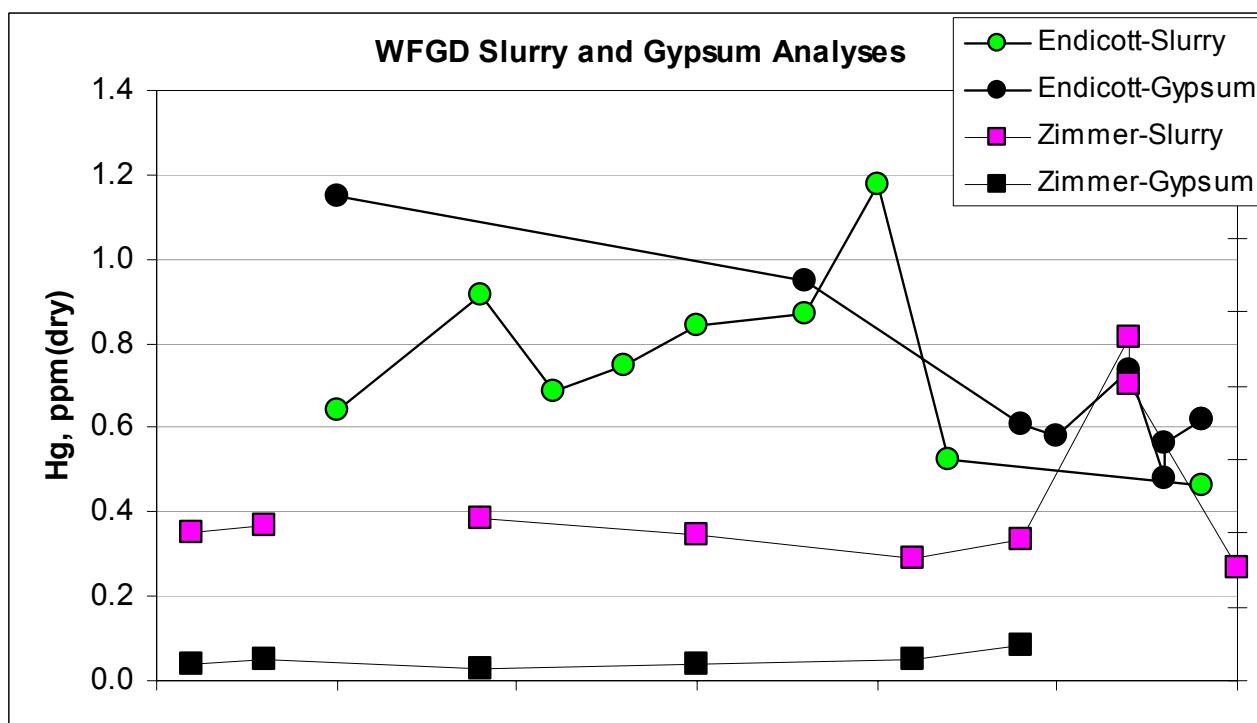


Figure 3.5-23: Mercury in Gypsum and Wet FGD Slurry Solids for Endicott and Zimmer

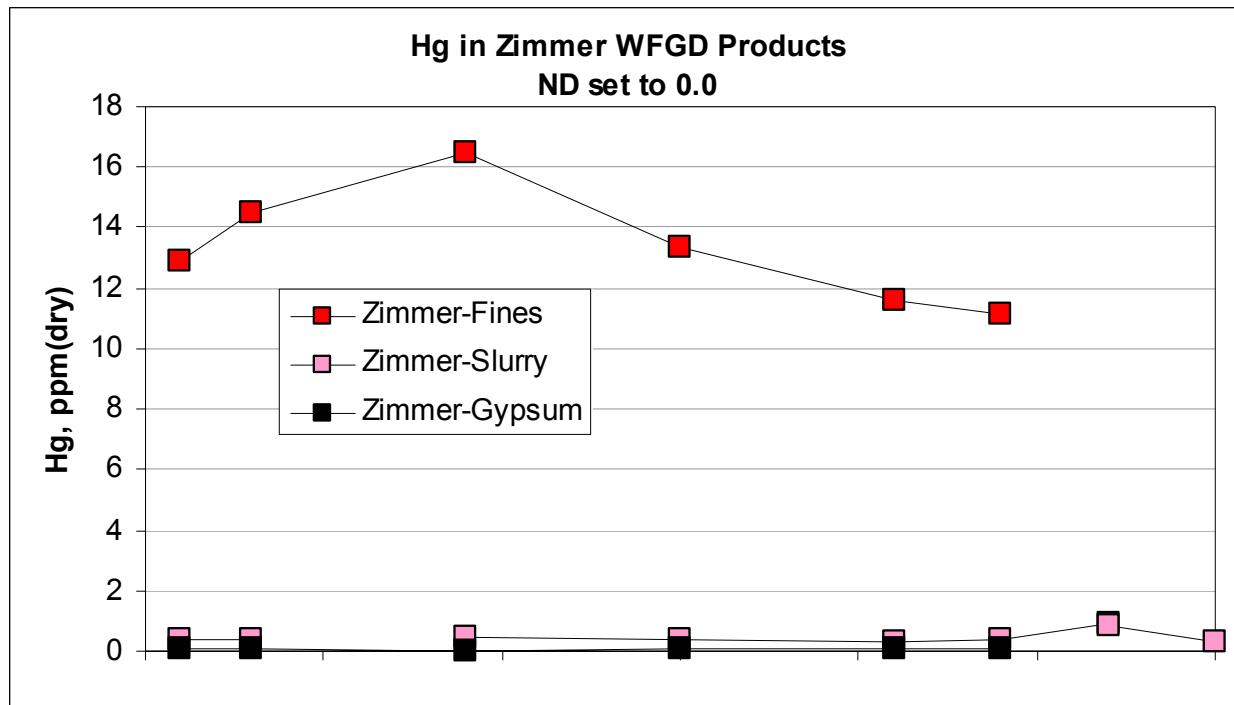


Figure 3.5-24: Mercury in Wet FGD CUB for Zimmer

3.5.1.4 Coal Analyses

Table 3.5-7 shows the ultimate coal analyses for Endicott along with Cl and Hg. Table 3.5-8 shows the Hg and Cl values for all the Endicott coal samples that were analyzed (some coals were tested only for Cl and Hg). Table 3.5-9 shows the ultimate analyses for the coal samples from Zimmer. Unfortunately, the coal samples collected at Zimmer during the program were destroyed after proximate coal analyses were performed (Appendix A). Only four samples were salvaged that corresponded to test dates. The row in Table 3.5-7 represents coal standards for mercury and chlorine. The Hg Standard was labeled BCR182 with Hg = 0.132 ppm. The Chlorine standard was labeled NIST 1630a with Cl = 1144±32 ppm.

Figures 3.5-25 and 3.5-26 show the mercury and chlorine concentration for the Endicott and Zimmer coals, respectively. The figures show that both mercury and chlorine varied widely throughout the test which made it difficult to discern the effect of reagent addition on the mercury concentration in the scrubber slurry or gypsum. In general, Hg and Cl were higher in the Endicott coals. This corresponds well with the OH data presented above in that the mercury concentration at the scrubber inlet measured at Endicott was higher than at Zimmer (and would be even higher if the mercury in the ESP ash was factored in). The higher Cl content of the Endicott coal may also contribute to the higher split between oxidized and elemental mercury in the flue gas.

Table 3.5-7: Endicott Ultimate Coal Analyses, Cl and Hg

Test ID	Composite	Daron: Pit 8	Ox: Meigs Cr 9	Det Ed: Mah 7	Buckl: Ohio 6	Buckl: Mah 7	1B	1C	1D
H ₂ O	5.23	4.72	6.67	6.42	7.21	6.82	6.72	6.36	6.90
C	66.70	70.38	64.70	67.90	65.56	70.25	70.17	74.98	68.35
H	4.83	5.10	4.53	4.75	4.47	4.79	4.71	5.03	4.85
N	1.22	1.29	1.27	1.33	1.24	1.33	1.34	1.43	1.29
S	3.45	3.64	2.64	2.77	1.75	1.87	1.13	1.21	2.58
Ash	12.49	13.18	14.73	15.46	12.77	13.68	9.53	10.18	8.06
Cl	0.02	0.02	0.05	0.05	0.01	0.01	0.11	0.12	0.06
O by Diff	6.06	6.39	7.36	7.74	7.53	8.07	6.59	7.05	7.60
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HV, Btu/lb	11944	12603	11552	12124	11563	12389	12323	13168	12225
M&A Free		14516		14341		14352		14660	
Cl, ppm	200		500		100		1100		600
Hg, ppm			0.130		0.151		0.119		0.203

Test ID	2A	5B	18A	24B	25B	27B	28B	29B	O-H Average
H ₂ O	9.4		8.13		7.13		8.61		7.61
C	66.81	73.74	62.38	67.90	66.77	71.90	64.65	70.74	65.53
H	4.51	4.98	4.21	4.58	4.49	4.83	4.37	4.78	4.87
N	1.38	1.52	1.40	1.52	1.37	1.47	1.34	1.47	1.34
S	1.96	2.16	1.96	2.13	2.51	2.70	3.11	3.40	2.29
Ash	9.59	10.59	15.65	17.03	11.28	12.15	11.73	12.83	11.86
Cl	0.06	0.07	0.07	0.08	0.07	0.07	0.08	0.09	0.07
O by Diff	6.29	6.94	6.20	6.76	6.38	6.88	6.11	6.69	6.79
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HV, Btu/lb	11819	13045	11057	12036	11935	12851	11625	12720	11190
M&A Free		14590		14506		14628		14592	
Cl, ppm	600		844		696		881		1013
Hg, ppm	0.219		0.134		0.340		0.303		997
									0.129
									0.108

Table 3.5-8: Endicott Coal: Cl, Hg

Test ID	Hg	Cl	Test ID	Hg	Cl
	ppm	ppm		ppm	ppm
Composite		200	9A	0.313	799
Pitt8	0.130	500	11A	0.148	787
MeigsCr9	0.151	100	13A	0.241	783
DE-Mah7	0.119	1100	15A	0.349	795
Ohio6A	0.199	600	18A	0.340	696
Bl-Mah7	0.233	500	20A	0.135	852
1B	0.214	500	22A	0.101	775
1C	0.181	600	23B	0.230	891
1D	0.203	200	24B	0.303	881
2A	0.219	600	25B	0.244	886
3B	0.247	906	26B	0.148	831
4B	0.229	1037	27B	0.266	921
5B	0.134	844	28B	0.129	1013
6B	0.134	1073	29B	0.108	997
7B	0.370	799	30B	0.268	1119
8B	0.199	842	Standard	0.145	1108

Hg Std =

0.132

BCR182

Cl Std =

1144 +/- 32

NIST 1630a

Table 3.5-9: Zimmer Ultimate Coal Analyses, Cl and Hg

O-H Test ID				37	38	44	44			
Unload Date	10/17/01	10/21/01	10/21/01	10/29/01	10/30/01	11/5/01	11/5/01	11/11/01	11/11/01	11/19/01
Ash	12.04	10.06	9.52	9.98	11.75	14.47	10.97	14.16	12.34	9.50
H	4.96	5.13	5.20	5.07	4.94	4.77	5.20	4.76	5.16	5.16
C	68.93	72.34	72.38	72.81	68.93	66.45	72.36	67.01	71.29	73.45
N	1.76	1.27	1.17	1.24	1.30	1.17	1.25	1.33	1.39	1.35
S	4.28	4.01	4.39	4.10	3.73	4.79	4.09	3.90	3.75	4.10
O	8.03	7.19	7.34	6.80	9.35	8.35	6.13	8.84	6.07	6.44
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Cl, ppm	216	534	481	373	217	217	321	326	587	481
Hg, ppm	0.24	0.13	0.11	0.12	0.21	0.18	0.10	0.14	0.15	0.10

Testing at Zimmer began 10/23/01 and ended 11/5/01

Endicott Coal Analyses

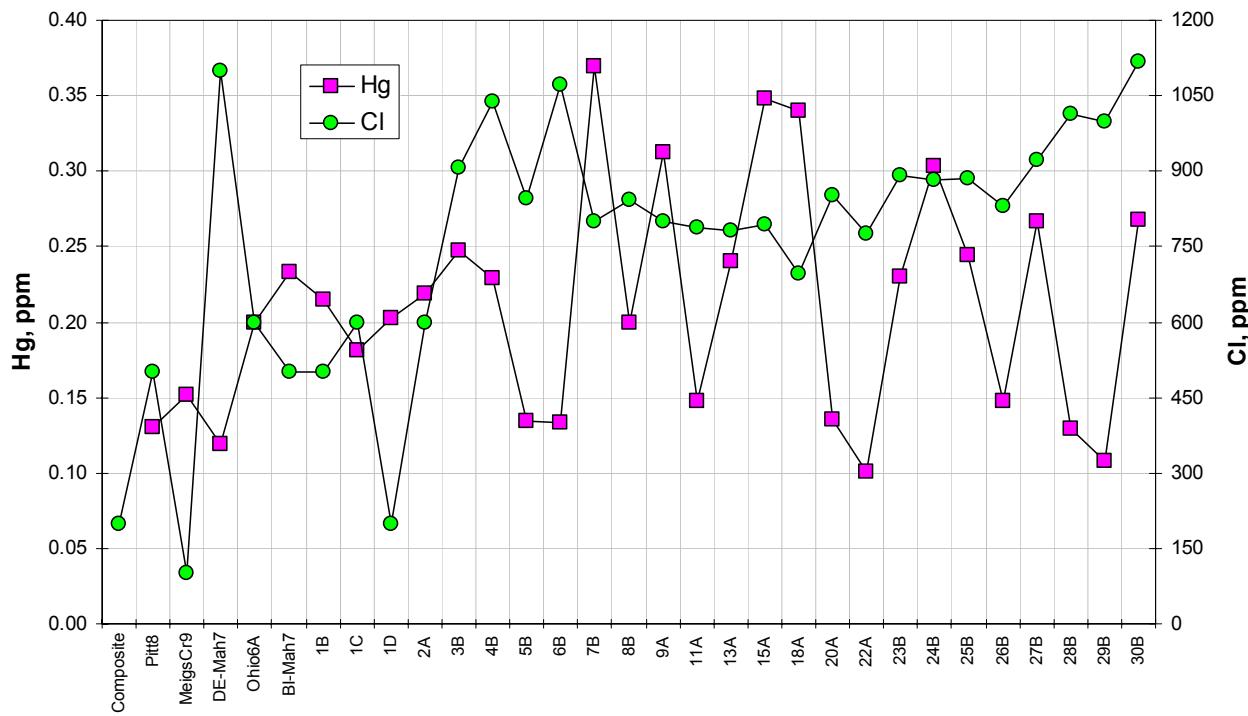


Figure 3.5-25: Cl and Hg in Endicott Coal Samples

Zimmer Coal Analyses

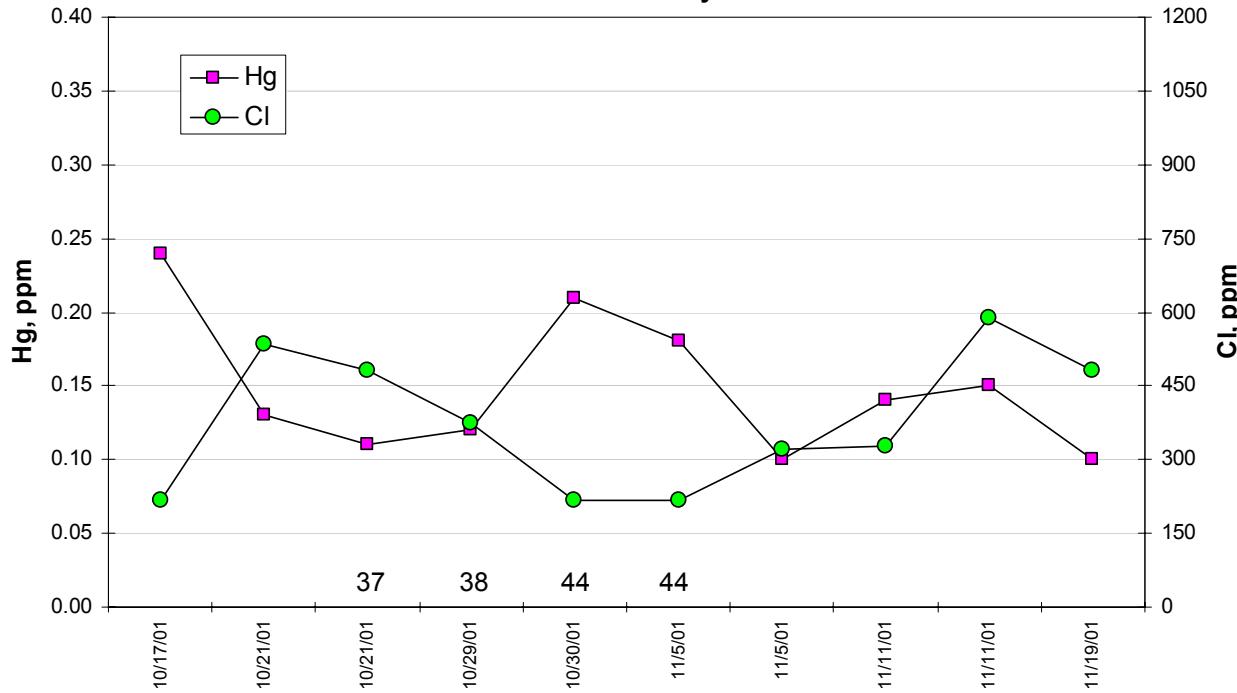


Figure 3.5-26: Cl and Hg in Zimmer Coal Samples

3.5.2 Thermal Dissociation Tests

Results from conventional wet chemical analyses have shown that the mercury in wet scrubber exists in a form that is insoluble in water. Calculations also show that the mercury content in most coals is so low that, even if all the mercury ended up in the scrubber by products and in a soluble form, the sludge would pass the standard TCLP test used to characterize pollutant leachability. Therefore, the purpose of this study was to determine the chemical form and thermal stability of mercury compounds in CUB.

Normal wet chemistry and other analytical methods cannot be used to distinguish the various mercury compounds in CUB because they are present in very small amounts. However, most mercury analyzers are capable of detecting mercury at very low concentrations in gas streams. MTI developed a method whereby CUB are heated in an oven and the mercury in the off gas is continuously measured to generate a plot of mercury concentration versus temperature.

Figure 3.5-27 shows vapor pressure curves for Hg^0 and several simple mercury salts that may exist in CUB. The figure shows that different mercury compounds have significantly different vapor pressures at any given temperature. Theoretically, these differences could be used to determine what mercury compounds exist in CUB since the mercury compounds should vaporize at different rates and produce an off gas of varying concentration depending on the temperature. The discussion below describes the apparatus used in this study, how standards were prepared and tested and, finally, the results of TDT from Endicott and Zimmer samples and from previous TDT. In all, 33 TDT were conducted as part of this study.

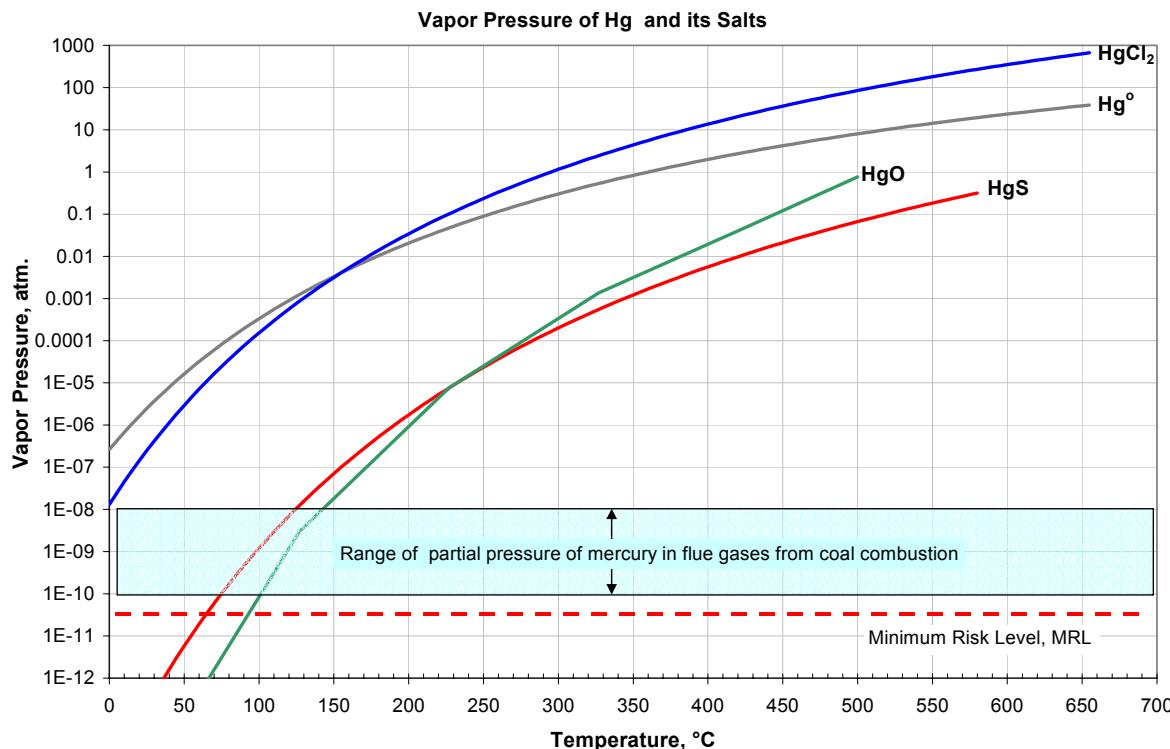


Figure 3.5-27: Vapor Pressure of Hg^0 and Select Hg Salts

3.5.2.1 Apparatus and Method

A schematic of the TDT apparatus is shown in Figure 3.5-28 and photographs 3.5-29 through 3.5-33. It consists of an Argon source, an Argon flow meter, a temperature controlled tube furnace, a high temperature furnace, an impinger to convert all mercury to Hg^0 (Figure 3.5-33), a chiller to remove water vapor, a PSA Mercury Analyzer (Figure 3.5-32) and a data acquisition system (Figure 3.5-30). Temperature is measured at the sample location (TC1), in the pyrolyzer (TC2), and at the junction of the pyrolyzer outlet and heated hose (TC3). Argon flow was held at 250 ml/min throughout the test. Test samples were placed in a glass sample boat (preheated to 800°C to purge mercury) and placed in the control oven (Figure 3.5-31). The samples were first heated to 95°C to evaporate all liquid water, then to 140°C to evolve the first waters of hydration from gypsum, and finally to 600°C at a rate of 6°C/min. The temperature of 140°C was chosen not to exceed the temperature at which the final waters of hydration evolve from the gypsum. This is the highest temperature that most CUBs are exposed to and is similar to the maximum temperature at a wallboard production plant.



Gases from the control oven then pass through the pyrolyzer and impinger to convert gaseous mercury compounds to elemental mercury. Mercury is then measured by atomic fluorescence in the PSA analyzer. For this application, the gold trap was bypassed so the detector would produce a continuous mercury signal.

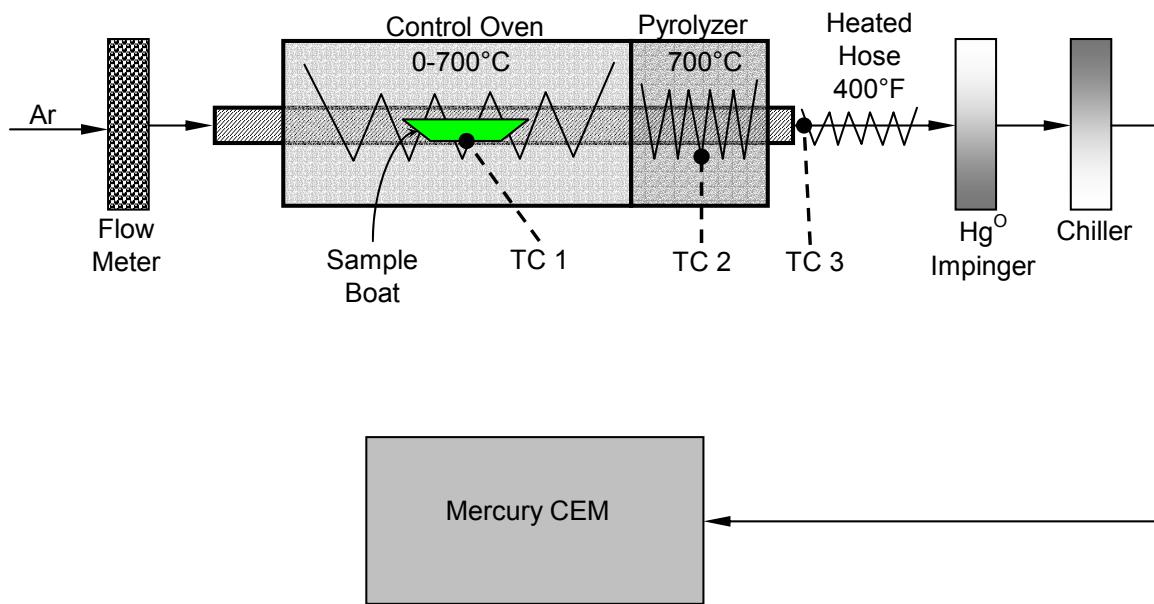


Figure 3.5-28: Thermal Dissociation Test Apparatus



Figure 3.5-29: TDT Heated Hose, Pyrolyzer, Control Oven, Argon Flow Meters

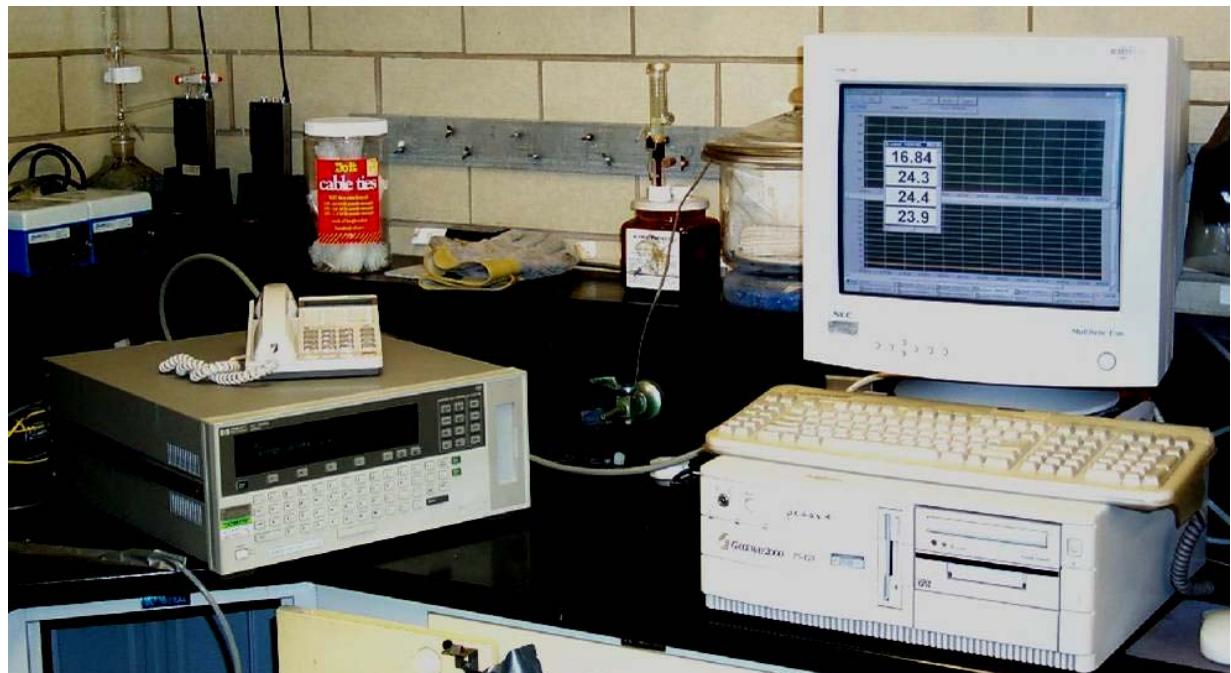


Figure 3.5-30: TDT Data Acquisition System



Figure 3.5-31: TDT, Inserting a Sample Boat into the Control Oven



Figure 3.5-32: PSA Mercury Analyzer and Preconditioner

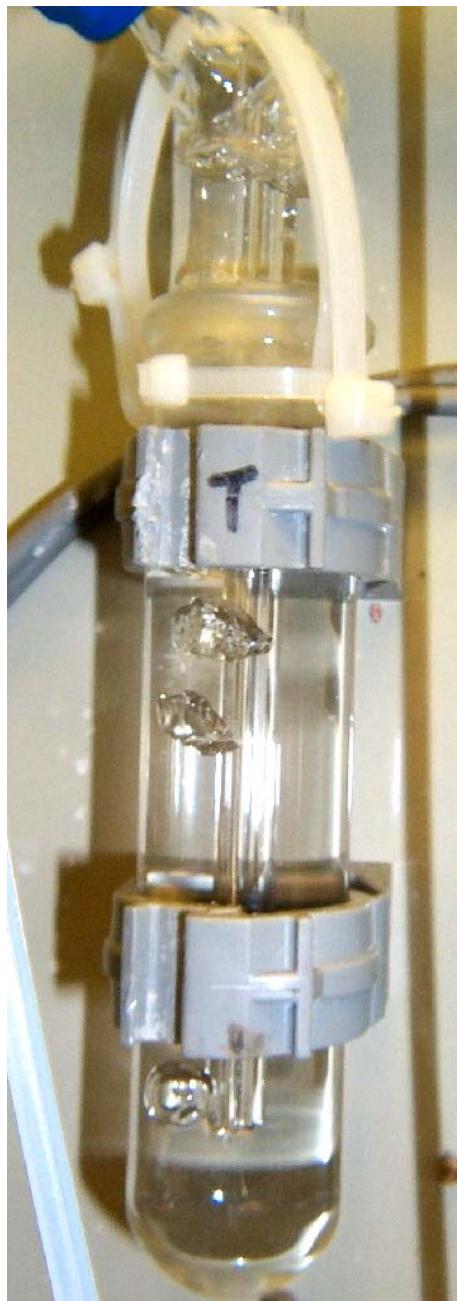


Figure 3.5-33: Hg^0 Impinger



Figure 3.5-34: Fines in Endicott Wet FGD Slurry

3.5.2.2 Preparation and Testing of Standards

For this method to be successful it was important to develop and test standards made from pure mercury compounds in order to generate plots for comparison with CUB. It was beyond the scope of this study to test all the mercury compounds of interest, so several compounds were chosen based on the ions most likely to be found in the wet scrubber environment, namely mercuric chloride (HgCl_2), mercuric sulfide (HgS), mercuric sulfate (HgSO_4) and mercuric oxide (HgO). A blank, consisting of an empty sample boat, was also tested.

To create the standards, the pure mercury compounds were ground and diluted with pure alumina to a target concentration of 1 ppm Hg. The alumina was prebaked at 800°C to drive off any mercury.

The Thermal Dissociation Curve. Figure 3.5-35 shows the Thermal Dissociation Curve (TDC) produced by a typical TDT. This test represents the HgO Standard and will be used to explain the various features of the TDC. The title gives a description of the sample tested, its weight and the OH Test ID if applicable. The x-axis represents time and a typical TDC requires 2-3 hours to generate depending on the amount of time required to dry the sample before heating to 140°C. The left-hand y-axis shows control oven temperature in °C. The oven temperature curve,

represented by the bold red line, shows that the sample was heated from room temperature to 95°C, held at 95°C for 5 min., heated at 6°C/min. to 140°C, held at 140°C for 10 min., then heated to 600°C at 6°C/min. The right-hand y-axis shows mercury concentration. No units are given because the software controlling the mercury analyzer was not written for the case in which the gold trap is bypassed as was done for this study. However, later in this section it will be shown that area under the mercury curve is equivalent to about 15 times the mercury measured by conventional methods in ppm. Furthermore, the most important information to be gleaned from the TDC is not the instantaneous mercury concentration but the temperature at which mercury is detected, the general shape of the mercury curve and the area under the curve. The right-hand y-axis also begins at ten instead of zero so that the background mercury value, another anomaly of operating the analyzer with the gold trap bypassed, is not shown. The conclusions from this figure are that a very small amount of mercury evolved at 140°C and the rest evolved and peaked at 300°C. It is also important to pay attention to the peak height and how it relates to the sample weight. For some samples, 0.01g produced peaks up to 550 indicating a high mercury concentration (wet FGD slurry fines), while 15g of other samples only produced peaks of 60 indicating very low mercury concentrations (Zimmer ESP ash). Therefore, peak heights cannot be directly compared unless sample weight is also considered. This TDC can now be compared with those produced from field test samples to see if there are similarities.

Blank. Figure 3.5-36 shows the TDC for a blank sample boat. The result was that no mercury evolved during the test since the signal was below 10 for the entire test. This indicates there was no mercury contamination on the boat or in the system.

Area vs. Concentration. Figure 3.5-37 shows the TDC for three sample weights of a HgSO_4 Standard prepared and tested during a previous program. This figure is reproduced here to demonstrate how the area under the curve can be used as a relative measure of mercury concentration in the samples. The sample weights tested were equivalent to about 1x, 0.5x and 0.25x and corresponded well with the normalized areas under the curves of 0.999, 0.496 and 0.245.

HgO Standard. Figures 3.5-38 and 3.5-39 show the TDCs for the HgO Standard from a test conducted in 2000¹ and one from the current project, respectively. These figures show good agreement between the two programs in that both curves were well defined and peaked at about 300°C.

HgS Standard. Figures 3.5-40 and 3.5-41 show the TDCs for the HgS Standard from a test conducted in 2000¹ and one from the current project, respectively. These figures show good agreement between the two programs in that both curves were well defined and peaked at about 300°C. Unfortunately, both HgS and HgO produced TDC, as would be predicted by the vapor pressure curves in Figure 3.5-27, so that it would be difficult to distinguish between these compounds by this method if they were present in the field samples.

HgSO_4 Standard. Figures 3.5-42 and 3.5-43 show the TDCs for the HgSO_4 Standard from a test conducted in 2000¹ and one from the current project, respectively. These figures both contain a minor peak at 300°C and a major peak at about 400°C. However, the TDC from 2002

has a more pronounced minor peak and a major peak at 380°C compared to 425°C from the TDC of 2000. The explanation for this is not clear, but several improvements were made to the apparatus since the previous program that greatly improved the overall performance of the system. The peak at 380°C is also the highest for any material tested to date.

HgCl₂ Standard. Figures 3.5-44 and 3.5-45 show the TDCs for the HgCl₂ Standard from a test conducted in 2000¹ and one from the current project, respectively. Although the figures appear different at first glance, they also have several similarities. First, both figures show some release of mercury at or below 140°C which the other standards do not. This is consistent with the vapor pressure curves in Figure 3.6-27 that show HgCl₂ and Hg⁰ having similar vapor pressure characteristics. Both TDC also exhibit a peak near 250°C and one at 300°C, however the strengths of the two peaks are quite different. More tests would be required to determine the cause of these differences. It may be related to the difficulties in preparing standards by the method of dry dilutions where microgram size samples of pure compounds have to be mixed and diluted by a factor of 1000.

The overall conclusions from the standard tests show that HgO and HgS produce well defined TDC that peak at 300°C, HgSO₄ produces multiple peaks with one at a much higher temperature than the other standards of about 400°C, and HgCl₂ also produces multiple peaks with one at around 250°C which is lower than the other standards.

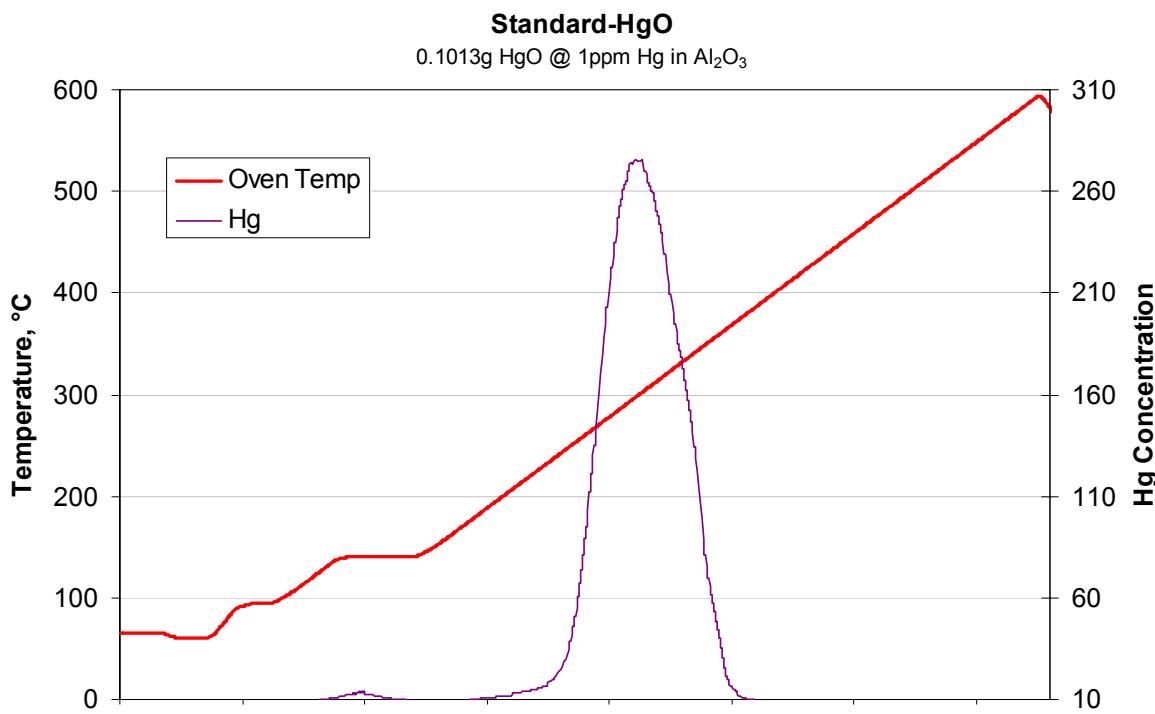


Figure 3.5-35: Example TDC

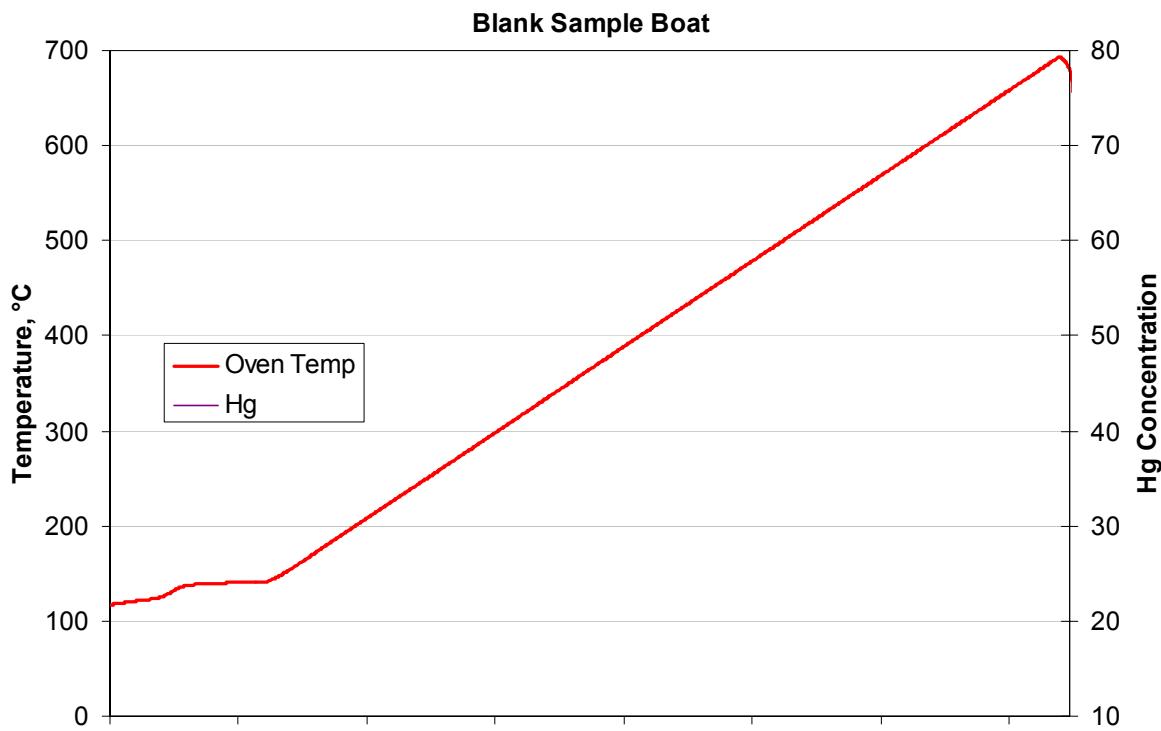


Figure 3.5-36: Blank Sample Boat

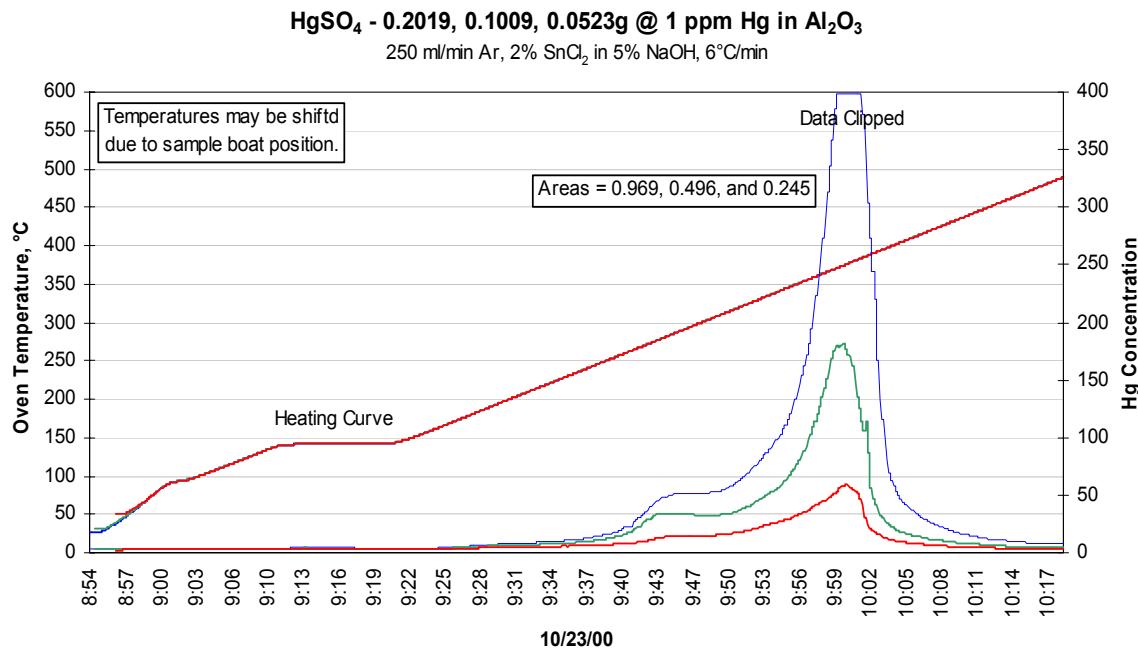


Figure 3.5-37: Multiple TDC for the HgSO₄ Standard at Various Sample Weights

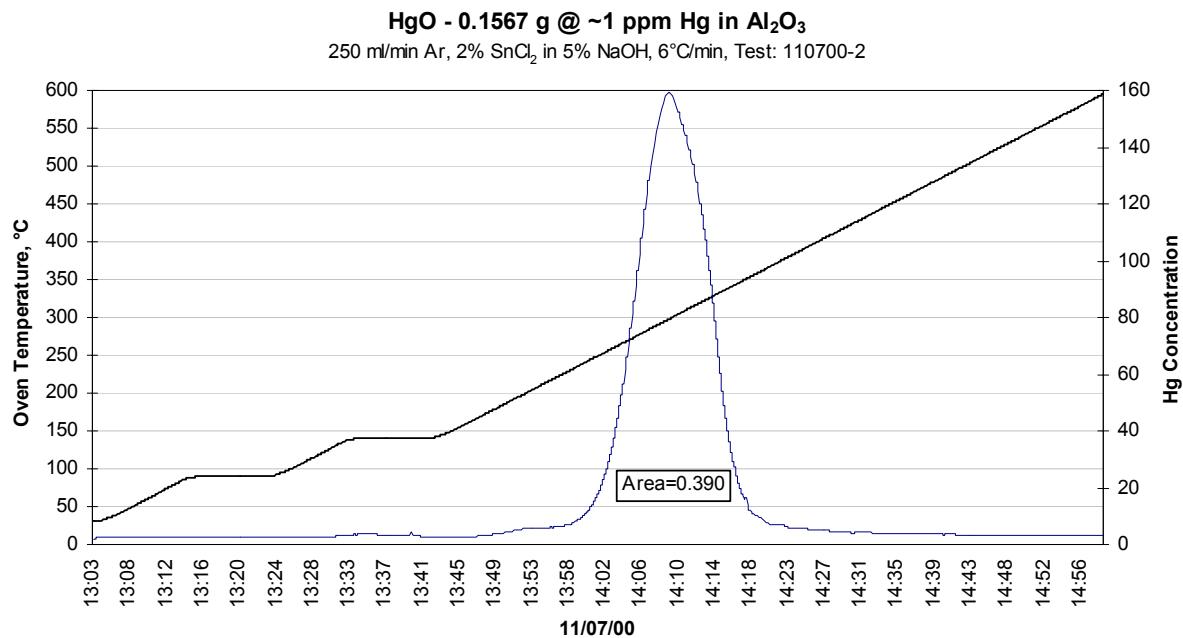


Figure 3.5-38: TDC for the HgO Standard Year 2000

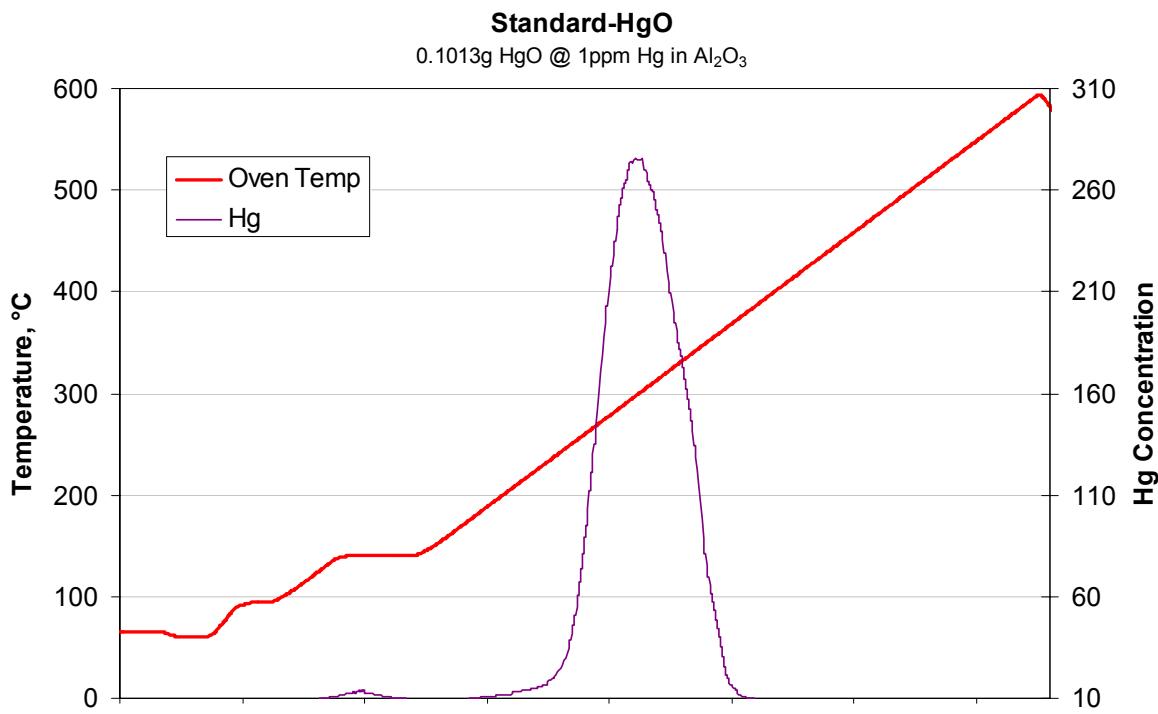


Figure 3.5-39: TDC for the HgO Standard Year 2002

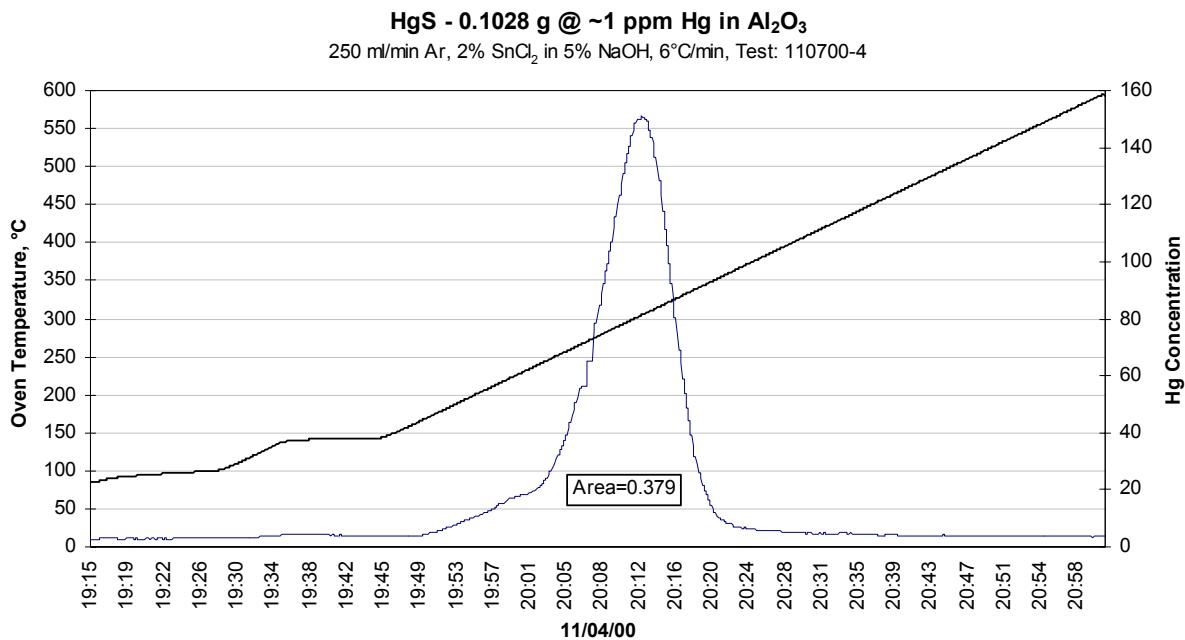


Figure 3.5-40: TDC for the HgS Standard Year 2000

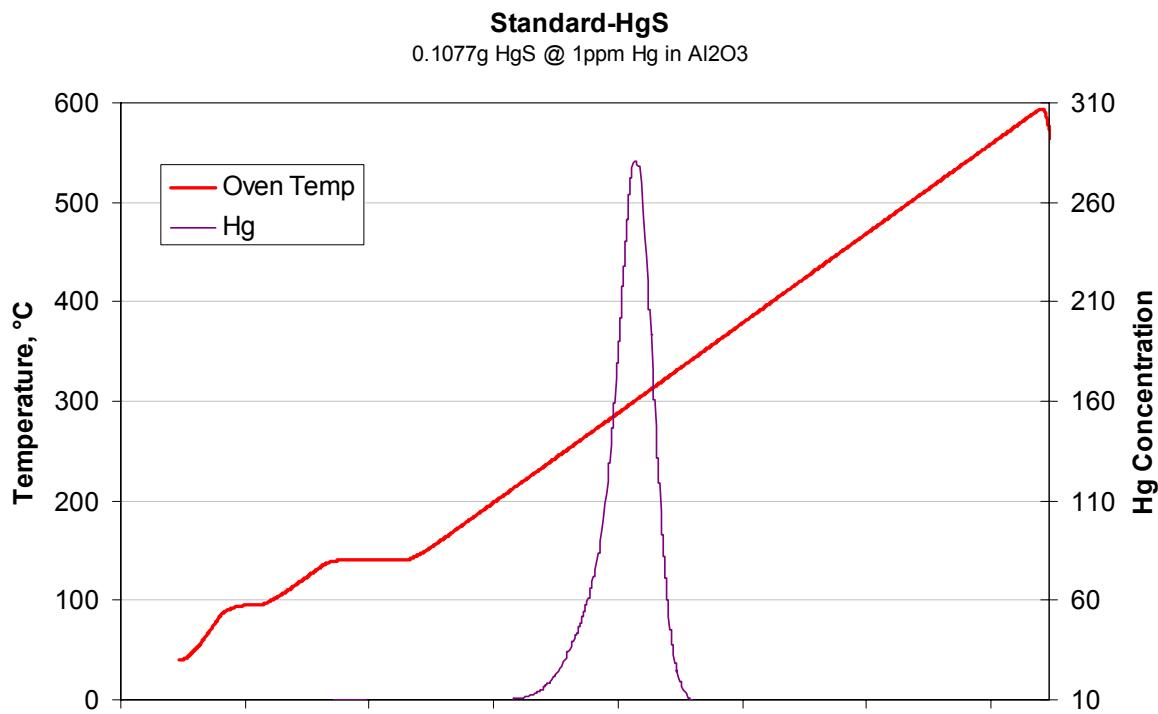


Figure 3.5-41: TDC for the HgS Standard Year 2002

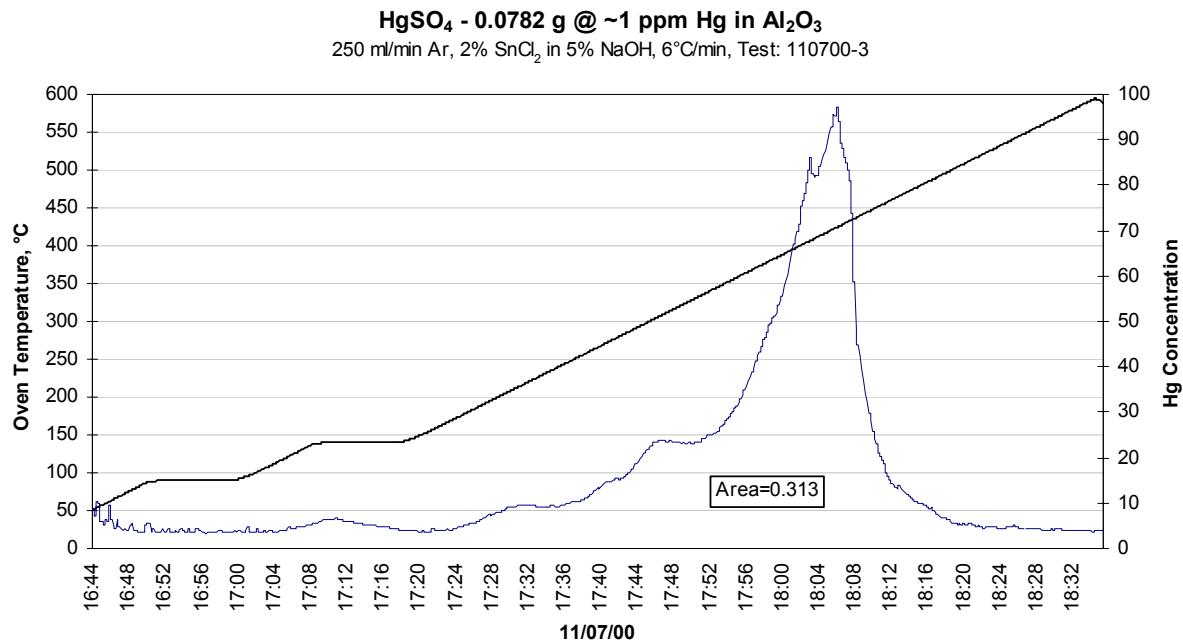


Figure 3.5-42: TDC for the HgSO₄ Standard in 2000

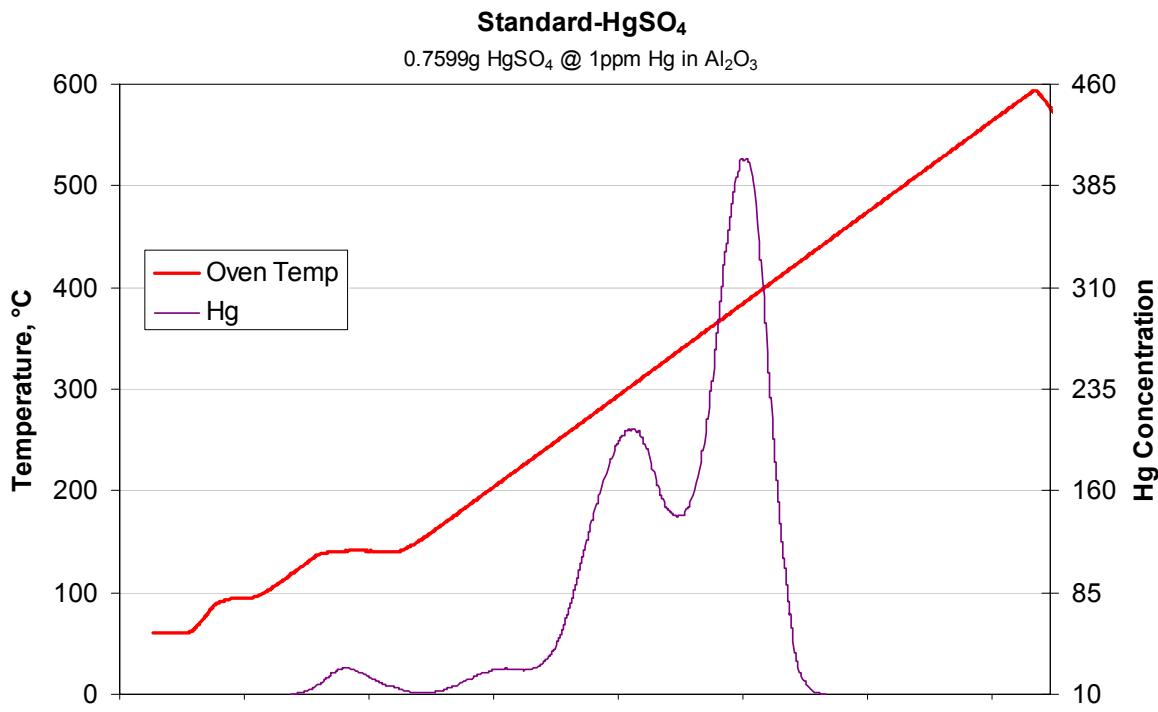


Figure 3.5-43: TDC for the HgSO₄ Standard in 2002

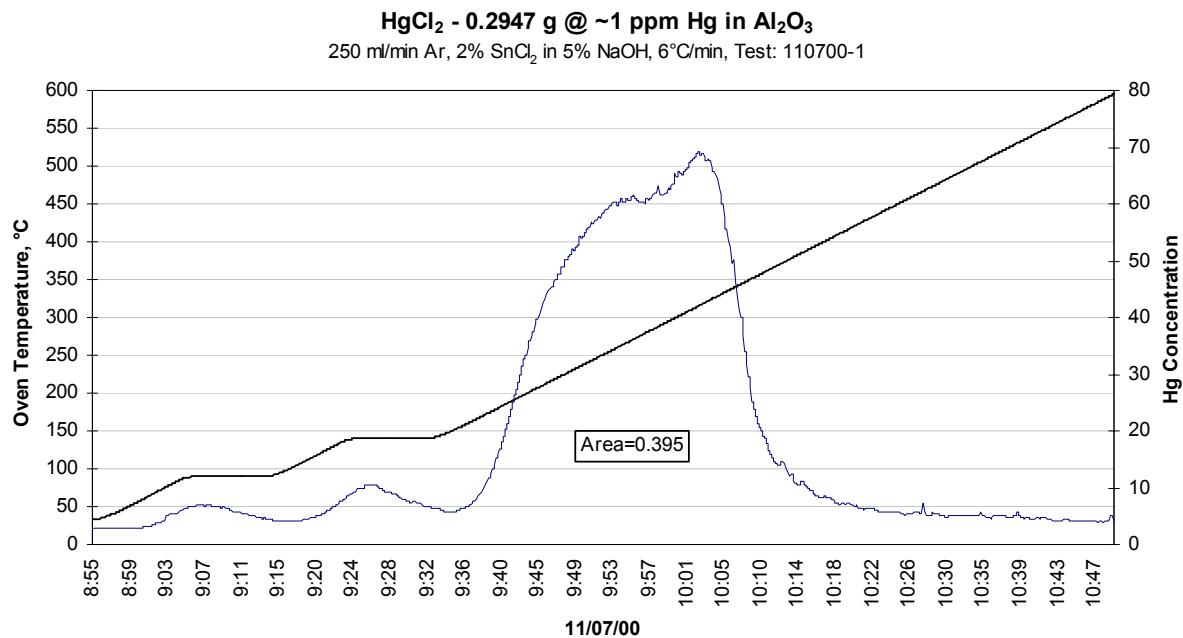


Figure 3.5-44: TDC for the HgCl₂ Standard in 2000

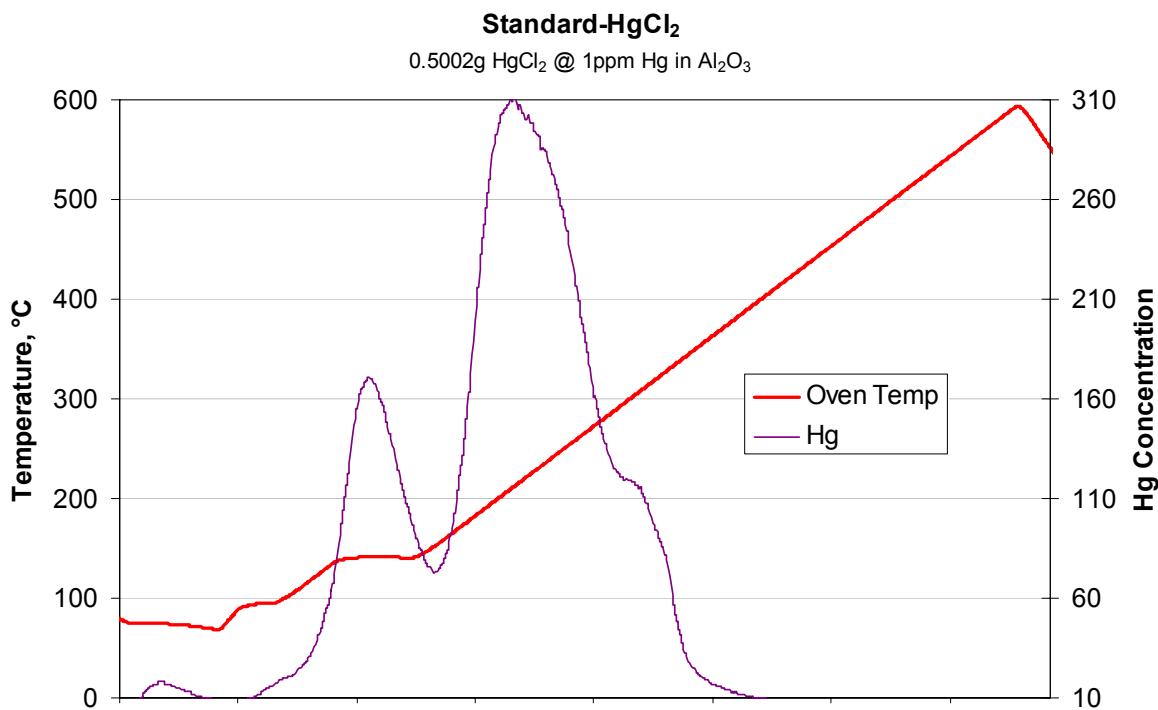


Figure 3.5-45: TDC for the HgCl₂ Standard in 2002

3.5.2.3 TDT Tests of Endicott and Zimmer Samples

This section presents TDT results for samples from both Endicott and Zimmer. Tables 3.5-3 and 3.5-4 show what samples were tested. A set of samples from the beginning (baseline) and end (steady state) of a test series was chosen to see if differences caused by the injection of the proprietary reagent could be ascertained. This section is organized into several parts comparing TDT data from Endicott and Zimmer for gypsum, ash, wet FGD slurry, wet FGD slurry fines and, finally, figures comparing TDT and conventional chemical analyses.

Gypsum. The first two TDCs, Figures 3.5-46 and 3.5-47, represent gypsum from Endicott and Zimmer, respectively for baseline and steady state w/reagent injection. Both sets of curves show that there was a slight increase in mercury concentration between the two tests, but because of the variation in coal mercury content on a day-to-day basis, it is hard to attribute this solely to reagent injection. However, both sets of curves show that the gypsum contains a mercury compound that produces a peak at about 250°C. This is different than any of the standards except possibly HgCl_2 , but HgCl_2 is soluble in water and was not detected in the liquid fractions of any of the samples so it is likely something different. The curves also show that a second compound may be present. For Zimmer, this is exhibited by the double peak, and in the Endicott samples it is exhibited by the slow rate of decay or large shoulder after the peak. Notice that the rate of decay after the peak is very sharp in the Zimmer curves in contrast to the Endicott curves.

ESP Ash. Figure 3.5-48 is the TDC for Endicott ESP Ash for three fields and Figure 3.5-49 is the TDC for Endicott Waste Ash, which is a combination of economizer, air heater and ESP ash that has been wetted in a pug mill to reduce dust problems while loading into trucks for disposal. The results for Zimmer Ash are not presented because, as shown in section 3.5.2, this ash contained very little mercury and 15 grams of sample barely produced peaks above the background level. The TDCs for the Endicott Ash show several things. First, the ESP ash contained a mercury compound that produced peaks between 360-400°C. This is somewhat consistent with the HgSO_4 standard but the shapes of the curves are very different. Secondly, the ash in the latter fields appear to contain a second mercury compound with a much lower peak temperature of about 220°C. This peak is barely present in the Field 1 sample, grows stronger in the Field 2 and becomes distinctly pronounced in Field 3. This suggests that different mercury compounds may be present depending on the make up of the ash collected in each field. Finally, the waste ash, a combination of economizer, air heater and ESP ash, produced a surprisingly different TDC than the ESP ash with a peak temperature of only about 280°C. However, it was sampled after being wetted in the pug mill to control dusting. It is known that HgSO_4 breaks down in water and may form HgS or HgO which is consistent with the TDCs.

Wet FGD Slurry. Figures 3.5-50 and 3.5-51 show the TDCs for wet FGD slurry solids from Endicott and Zimmer respectively. The three curves in each figure represent a baseline, steady state, and a dried sample. A dried sample, dried overnight at 95°F, was tested to determine if drying affected the TDC. It is much easier to test dried samples since much smaller amounts are needed and there is no need for lengthy drying times before heating to 140°C. The curves show a significant difference between Endicott and Zimmer, which is not unexpected since Zimmer uses Thiosorbic Lime and natural oxidation in the scrubber, whereas Endicott is a conventional limestone forced oxidation system. The Zimmer slurry produced two distinct peaks, a main peak

at about 220°C and a minor peak at about 400°C. In contrast, the Endicott slurry produced several small peaks at or below 140°C, a main peak at about 280°C and a smaller shoulder peak at about 350°C that was followed by a gradual decay. Drying had no apparent effect on the samples. The TDCs produced by the slurry are different than those produced by the gypsum. This can be explained for Zimmer since the slurry is subjected to a multistage chemical process in the *ex situ* oxidation system. However, the slurry at Endicott is simply pumped to a thickener and the underflow is sent to filter drums to separate the gypsum. There are other streams added to the thickener, like the material from the scrubber building sumps, so some additional chemical reactions may occur.

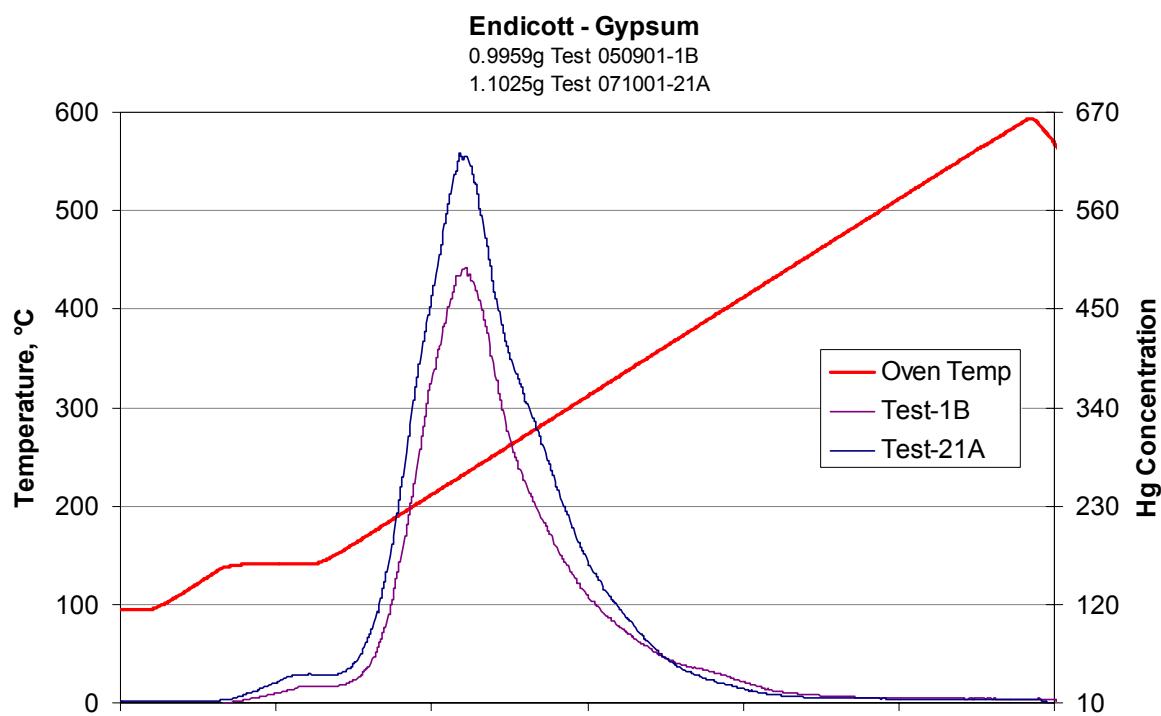


Figure 3.5-46: TDC for Endicott Gypsum

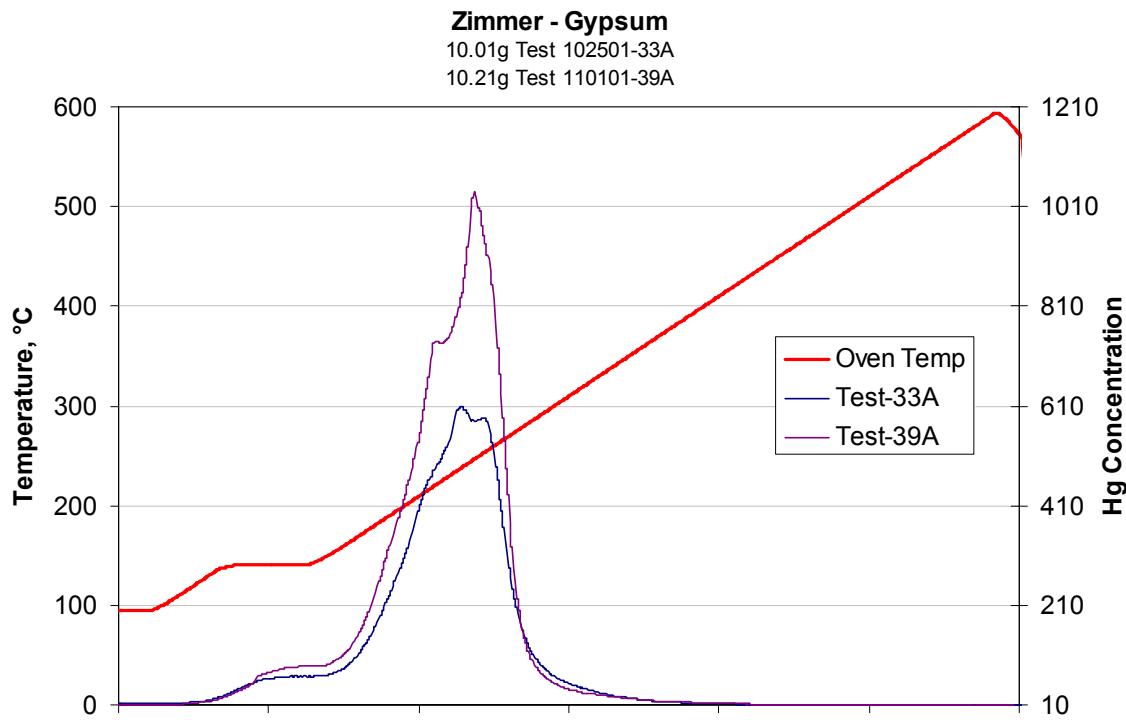


Figure 3.5-47: TDC for Zimmer Gypsum

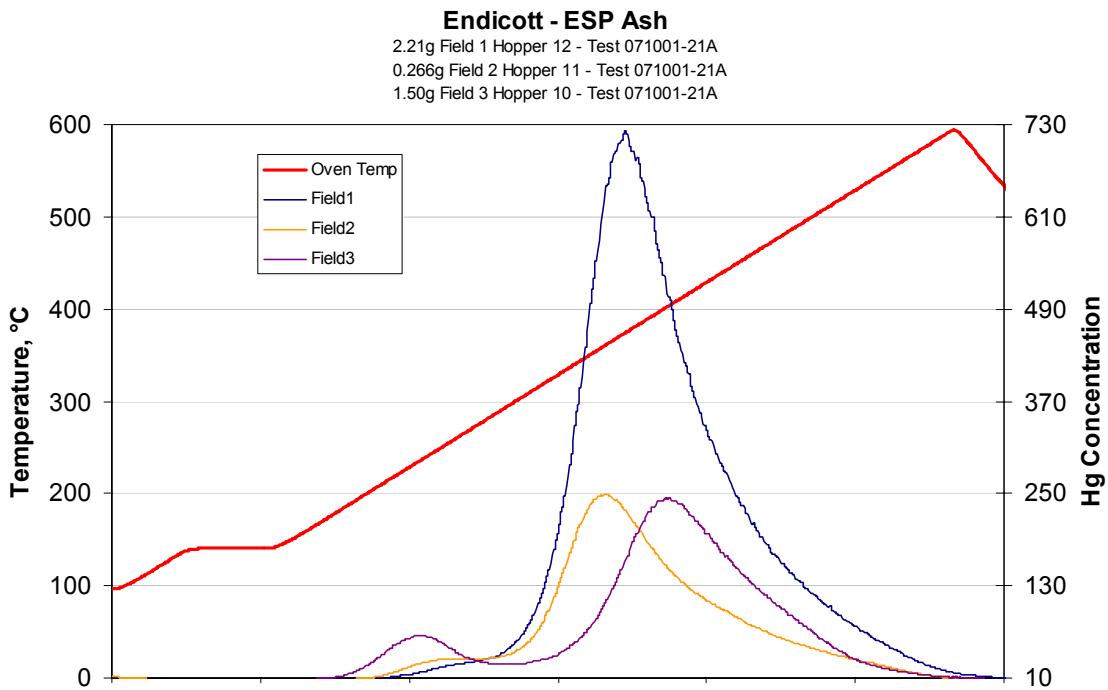


Figure 3.5-48: TDC for Endicott ESP Ash by Field

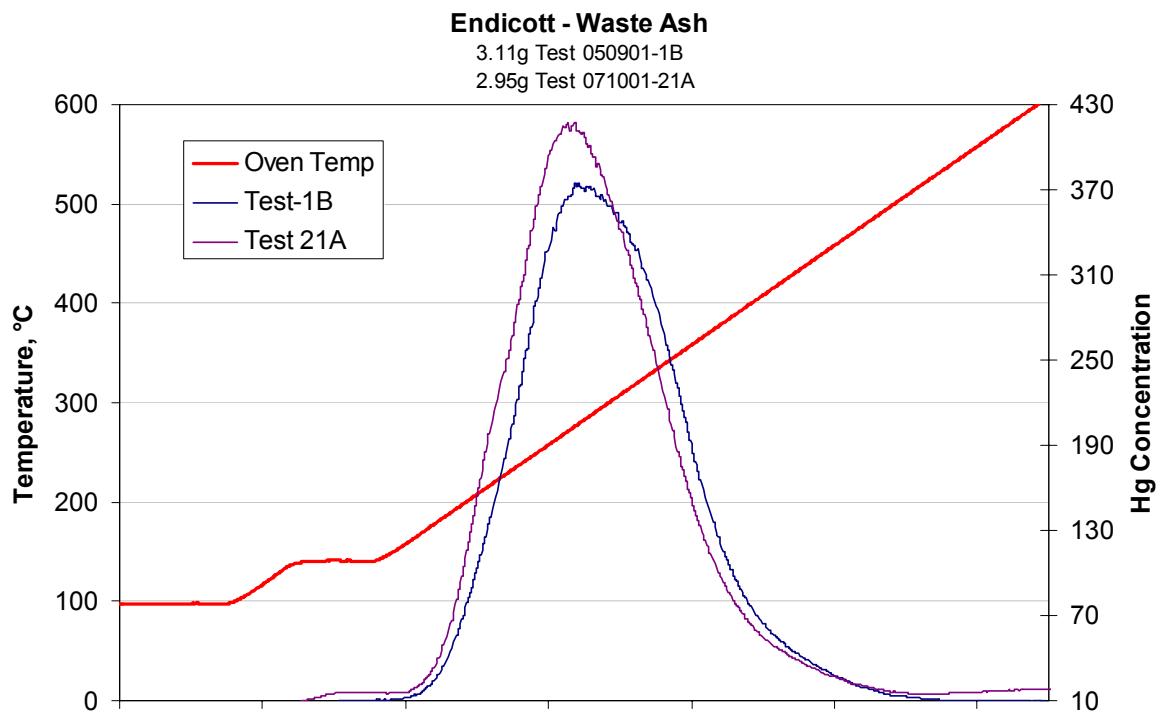


Figure 3.5-49: TDC for Endicott Waste Ash

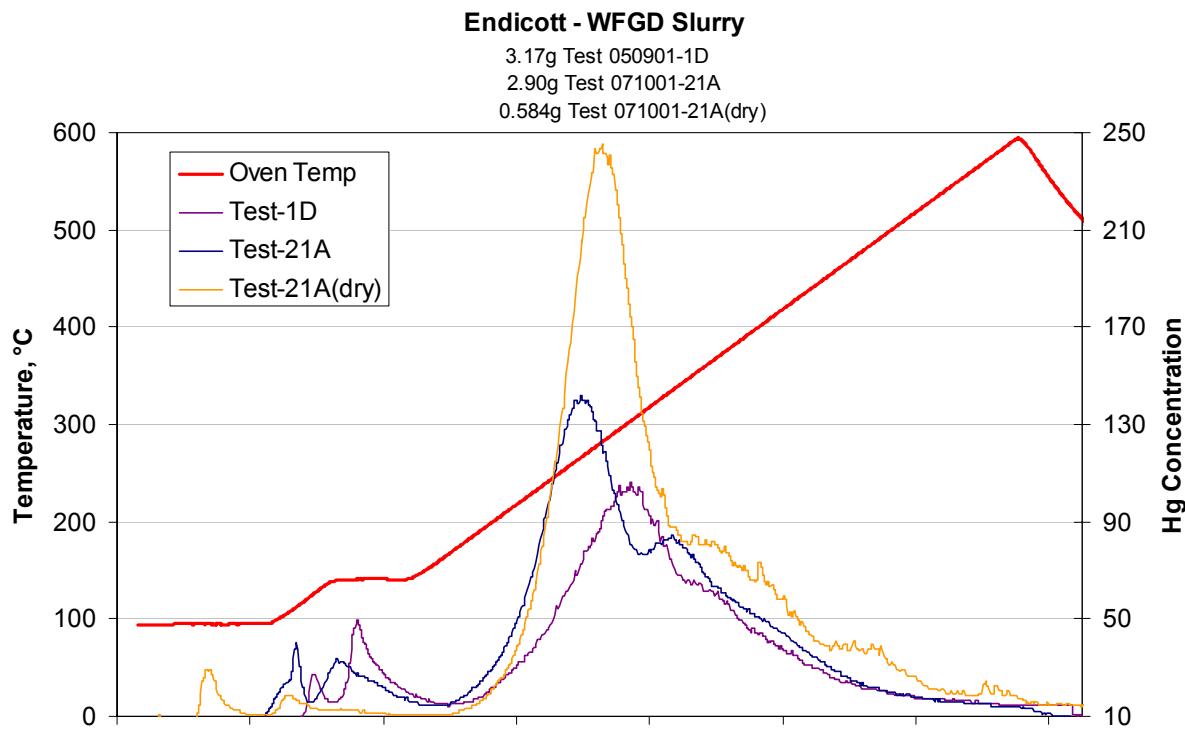


Figure 3.5-50: TDC for Endicott Wet FGD Slurry

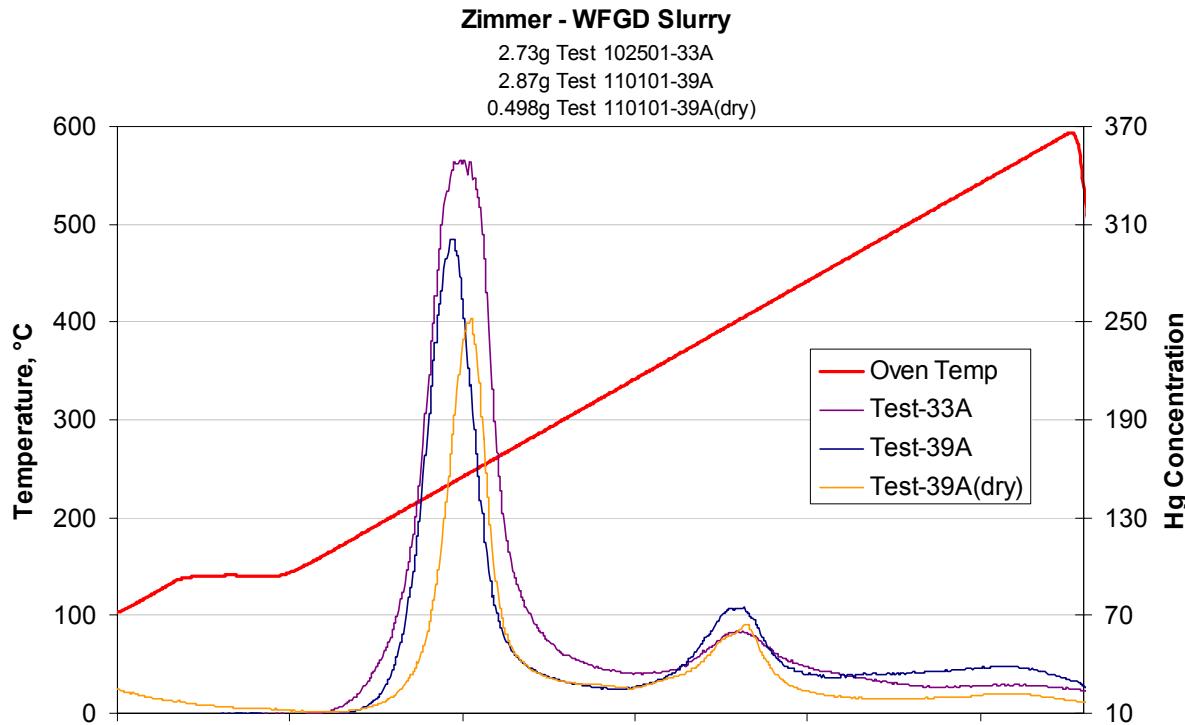


Figure 3.5-51: TDC for Zimmer Wet FGD Slurry

Wet FGD Slurry Fines. Figures 3.5-52 and 3.5-53 show the TDCs for wet FGD slurry fines from Endicott and Zimmer respectively. Slurry fines are separated from the gypsum product and disposed separately at Zimmer (Figure 3.5-19). At Endicott, the fines build up in the slurry until they are removed with the gypsum on the filter drums. To get a sample of the fines from Endicott, a slurry sample was mixed, and then allowed to stand until only the white gypsum portion settled. The liquid above the white layer was still black at this point from the suspended fines. This dark liquid was drawn off, filtered, and dried overnight at 95°F. Figure 3.5-34 shows the dark, fine layer on a completely settled sample of scrubber slurry from Endicott. The Endicott fines produced a single, well defined peak at about 240°C. This is consistent with the major peak in both the gypsum and the slurry and is, therefore, the likely source for most of the mercury in these samples. Note that only 0.01 g of this material produced a peak over 500 whereas 0.58 g of the dried slurry only produced a peak of 250 which means the mercury is heavily concentrated in the fines. The same holds true for the Zimmer fines except that the peak temperature is about 250°C and the mercury concentration is a bit lower as compared to the slurry. However, the separation method employed at Zimmer is not as discriminating as what was done in the lab.

Water Treatment Sludge. Figure 3.5-54 shows the TDC for the water treatment sludge solids from Endicott. Water treatment sludge is a material produced at Endicott in the water treatment plant. It is pumped to the wet scrubber to take advantage of its high alkalinity. All waste water streams at Endicott are pumped to the plant and undergo a multistage process including

acidification, precipitation, clarification, and neutralization, before being discharged. The sludge from the neutralization step overflows a weir in the bottom of a tank (Figure 3.5-7) and is periodically pumped to the wet scrubber. This stream was sampled because it is a possible source of mercury to the system, and the solids were found to contain about as much mercury as the wet FGD slurry solids (Table 3.5-5). However, the flow rate of this stream is very small and so it is not a main source of mercury. The TDC for this material shows two peaks, a major peak at about 260°C and a minor peak at 380°C. The material from the earlier test (Test 1A) also had a peak at about 330°C. The two main peaks look very similar to those produced by the wet FGD slurry from Zimmer which suggests that the two materials contain the same mercury compounds or compounds with similar vapor pressures.

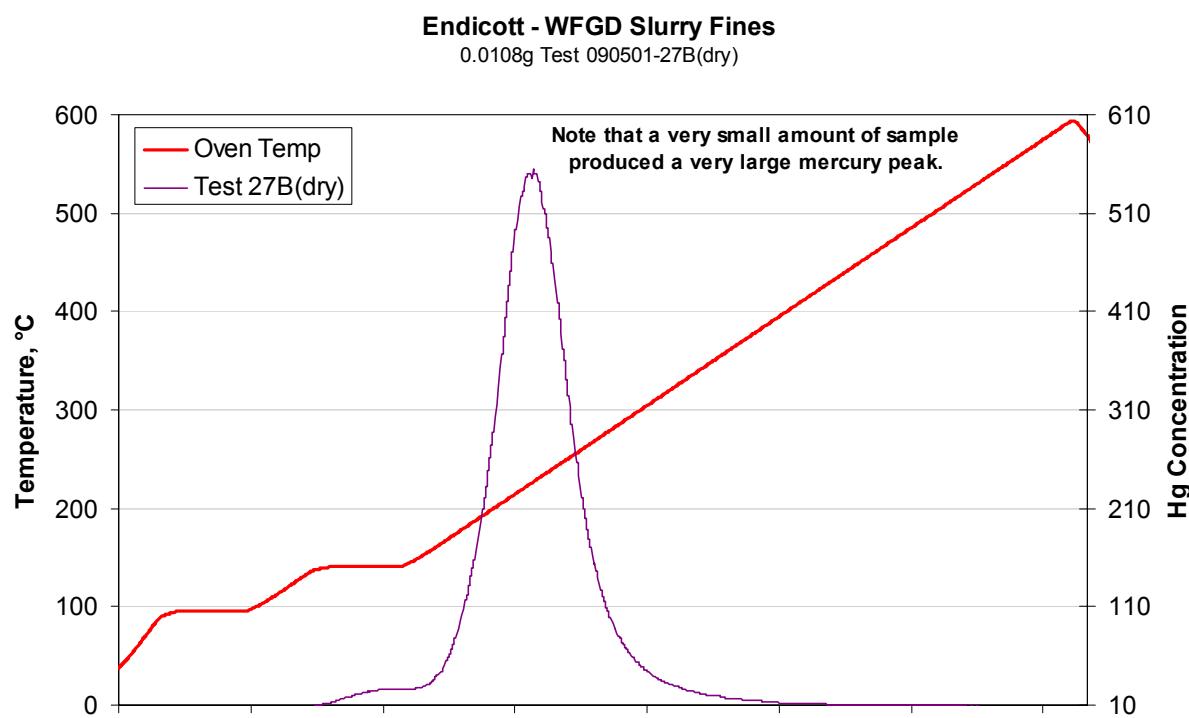


Figure 3.5-52: TDC for Endicott Wet FGD Slurry Fines

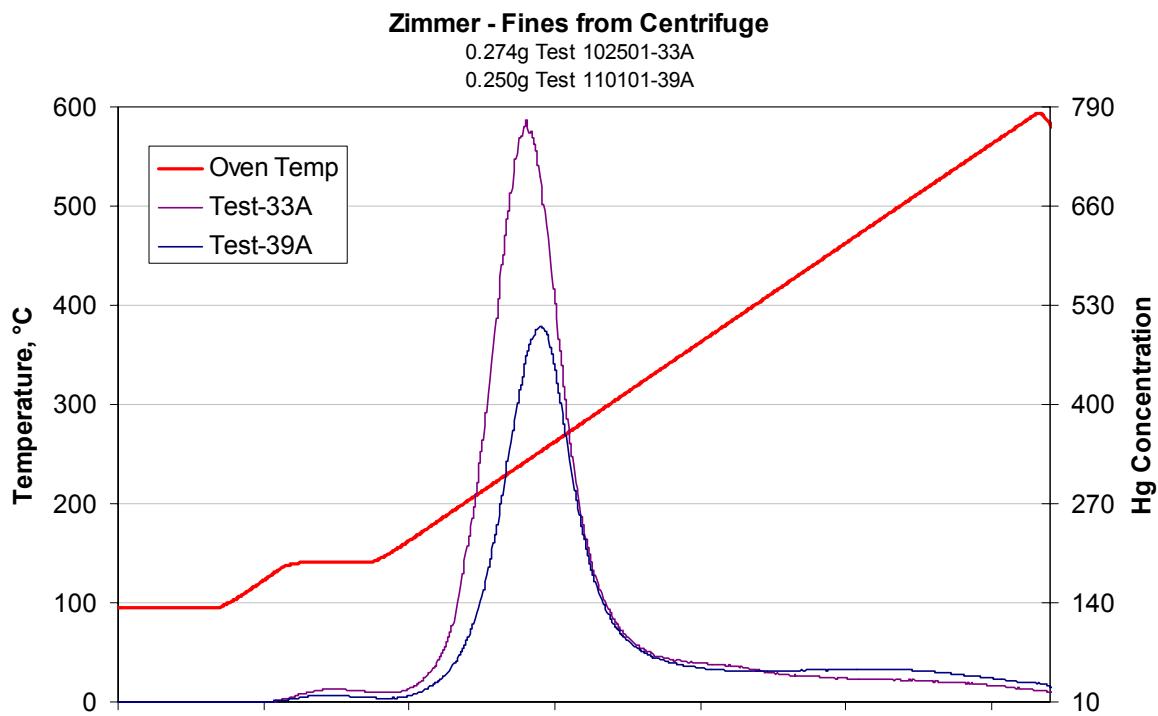


Figure 3.5-53: TDC for Zimmer Wet FGD Slurry Fines

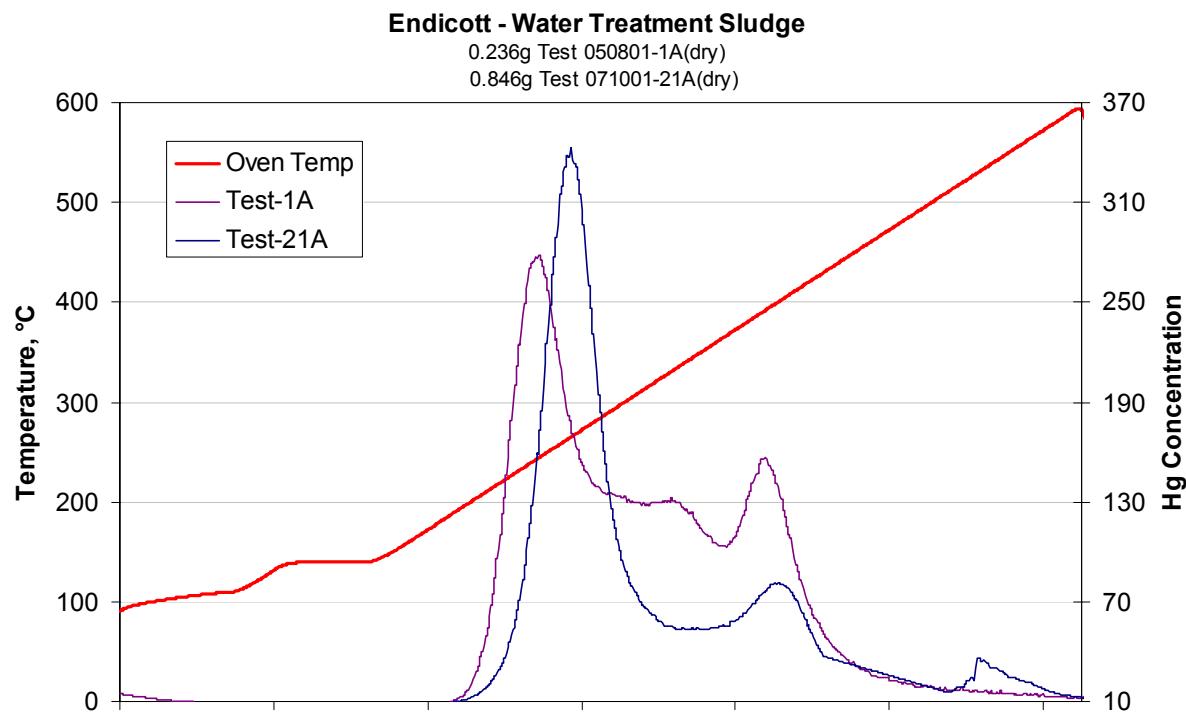


Figure 3.5-54: TDC for Endicott Water Treatment Sludge

3.5.2.4 TDT vs. Conventional Chemistry

Figures 3.5-55 through 3.5-57 present a comparison of TDT data and conventional chemical analyses. To generate these plots, the area under the TDC was calculated by:

$$\text{Area} = \left(\int ((\text{Hg}^n - 10 + \text{Hg}^{n+1} - 10) / 2 * \Delta t) \right) / \text{wt} / 1000$$

Where:

Hg \equiv mercury concentration measured by the PSA analyzer,
 n \equiv the number assigned to each Hg value measured,
 Δt \equiv time interval between n and $n+1$ ($\Delta t = 5$ sec for this study),
 wt \equiv dry sample weight in grams

This equation states that the average value between two successive outputs from the mercury analyzer is multiplied by the time interval and summed over the entire length of the test, and the sum is then divided by the sample weight and by 1000. A value of 10 was subtracted from each output to nullify the background signal. The sum was divided by 1000 simply to produce values for the area that were in a reasonable range.

Figure 3.5-55 shows the TDT Area plotted on the right-hand y-axis and the Hg concentration from conventional chemical analyses on the left-hand axis for the ESP and waste ash samples from Endicott and Zimmer. The data is further separated into columns representing the particular field the sample came from. This figure shows that there is good agreement between the two methods and that further dividing the TDT Area by 15 would produce a value equivalent to the ppm values for the conventional analyses. It further shows that the TDT correctly distinguished between the relatively high mercury in the Endicott ash compared to the Zimmer ash.

Figure 3.5-56 is a similar comparison for the slurry and gypsum samples. Again, there is good agreement between the two methods when the TDT areas are factored by 15. The TDC area method again correctly indicated the low mercury levels in the Zimmer Gypsum as compared to other samples.

Finally, Figure 3.5-57 shows the same comparison for the wet FGD slurry fines, which contained the highest mercury concentration of any of the samples tested. This figure shows that there is good agreement between the methods for the Zimmer Fines, but no conventional chemical analyses were performed on the Endicott fines. Therefore, a one-to-one comparison shows that converting the TDT area to ppm yields a value for the Endicott fines of about 38 ppm Hg . This is about twice as high as the Zimmer fines and much higher than the Endicott gypsum values of 1 ppm Hg , but it is consistent with what was seen for the Zimmer samples.

There are two important conclusions from the TDT study. First, it confirmed, for two very different plants, that the mercury captured by wet scrubbers is not bound with the larger gypsum crystals but is present as a separate, fine particulate or is bound to other fine particulate in the slurry. This suggests that the mercury captured by wet scrubbers can be separated from the gypsum product by adding a step to separate the fines. The fines can then be disposed properly.

At Zimmer, a hydroclone is used to separate the fines, but many other commercial products could be employed depending on the particular circumstances of the site. Second, the TDT method is a simple and viable way to measure the mercury concentration in CUB and it also produces information pertaining to the thermal stability of the mercury compounds in the sample.

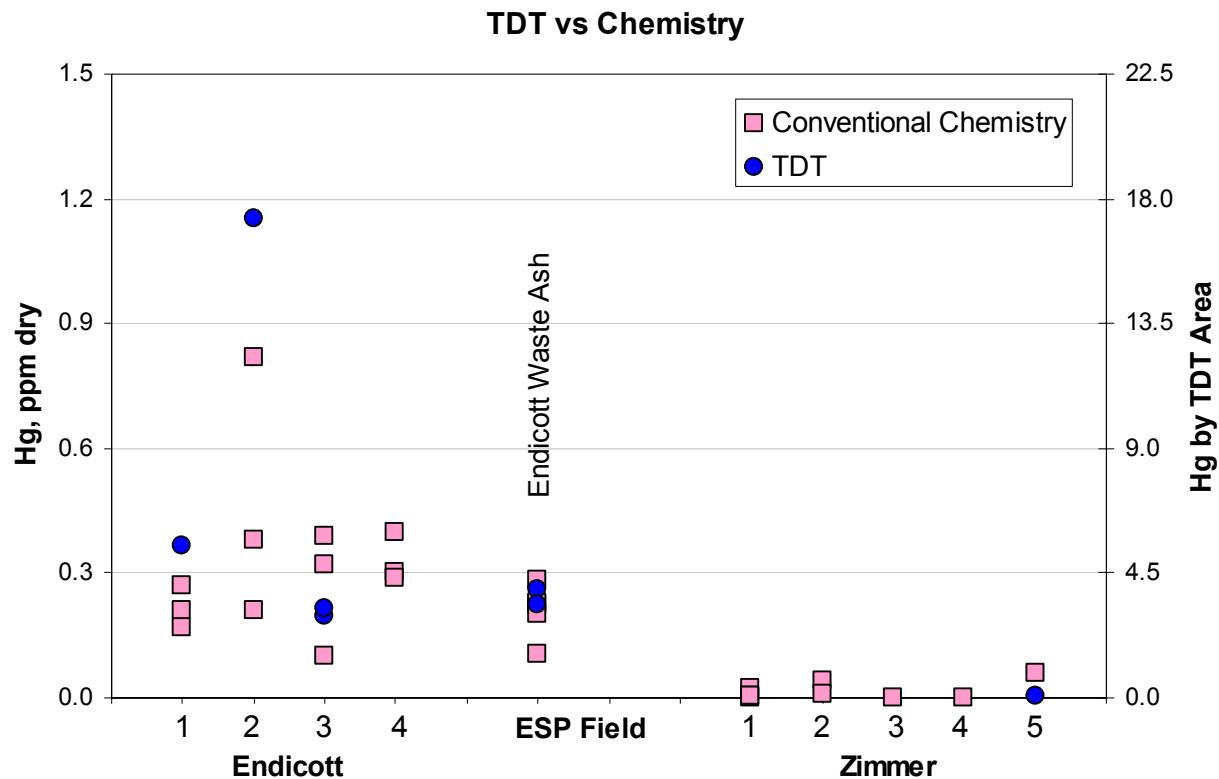


Figure 3.5-55: TDT vs. Conventional Chemistry for ESP and Waste Ash

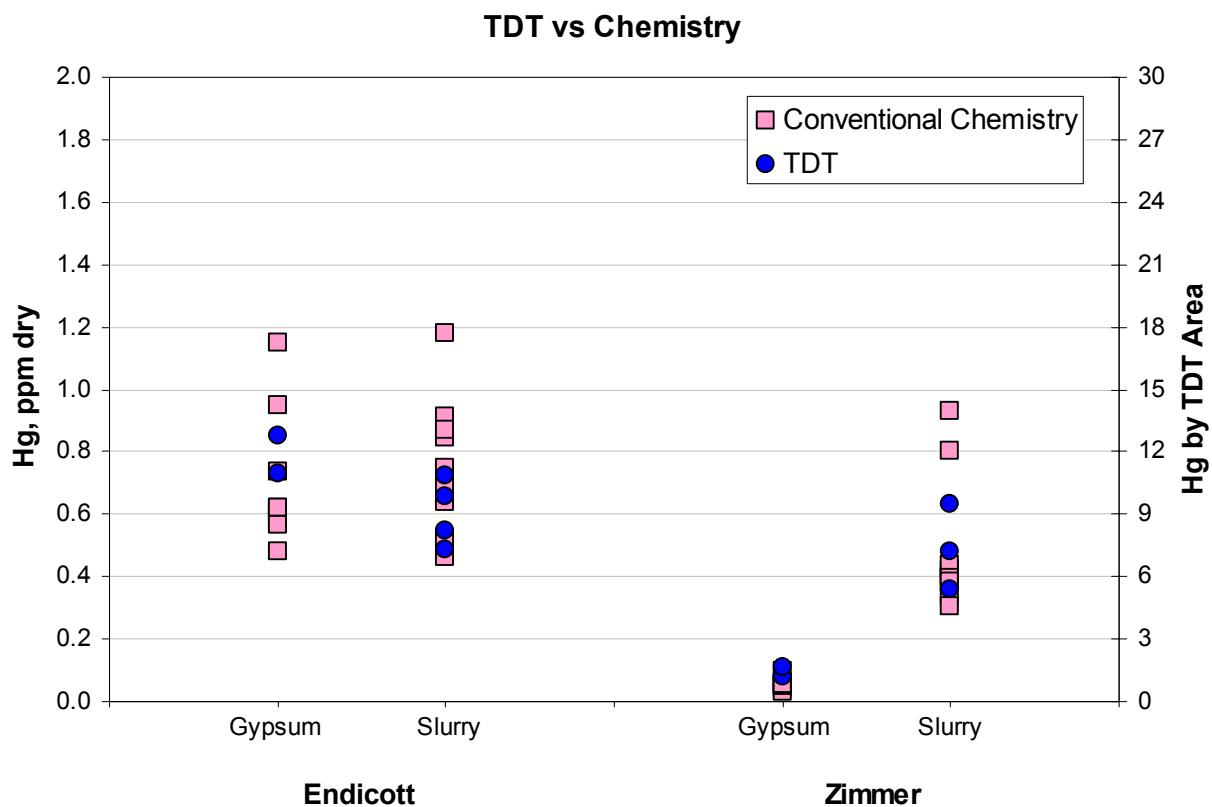


Figure 3.5-56: TDT vs. Conventional Chemistry for Wet FGD Slurry and Gypsum

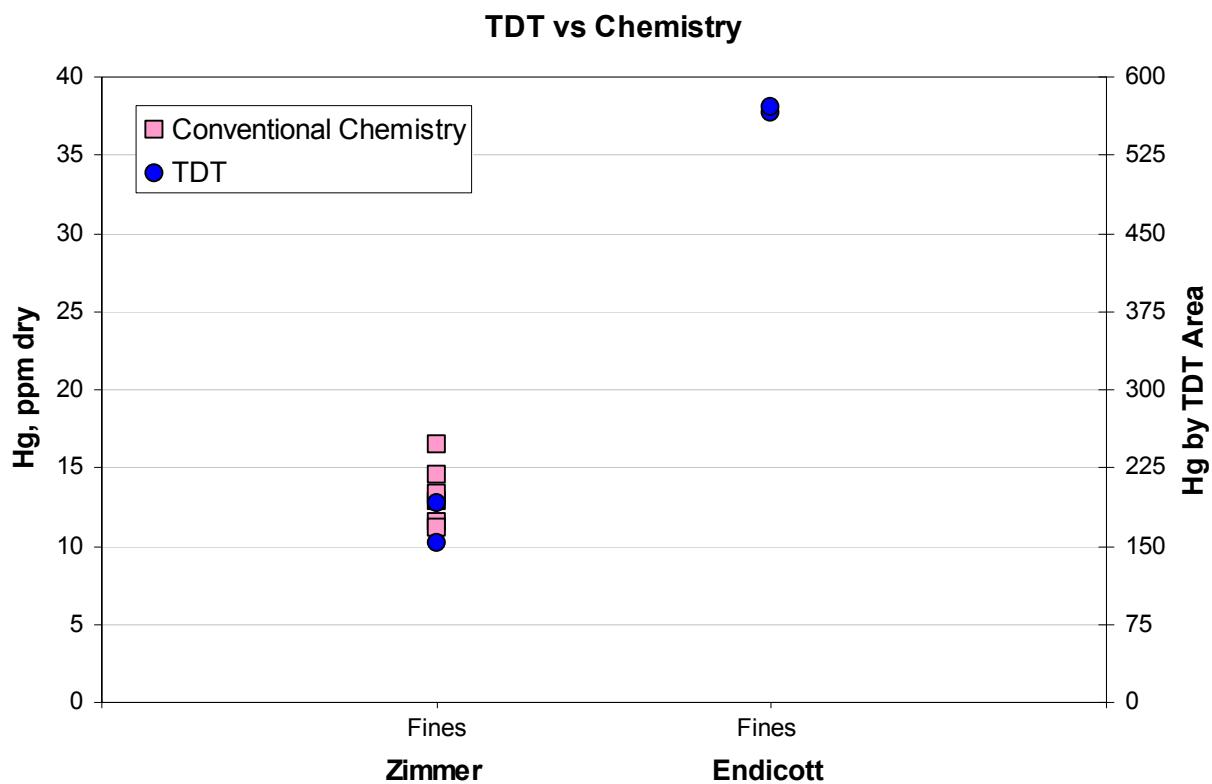


Figure 3.5-57: TDT vs. Conventional Chemistry for Wet FGD Slurry Fines

3.5.3 Mercury Tracking

Data from the chemical analyses and OH results were combined with flow rate data for the various streams to determine what the major sources of mercury input and output were for Zimmer and Endicott. It should be noted that it was never a goal of this project to obtain the data and samples required to do a thorough mercury mass balance for the plants. The purpose of this section is to depict how the mercury transits through the plants.

Several assumptions were made to perform the analysis presented below because several of the major process stream flow rates are not measured directly. Therefore, flow rate data was obtained from various sources including mass balance flow sheets, conversations with plant personnel, combustion calculations and the plants' data acquisition system. Gas flow rates were determined from in-house combustion calculations and were based on average coal compositions of samples taken during this program and on the knowledge of plant personnel concerning normal coal consumption. All calculations were done assuming full-load operation even though both plants cycled during the test period. The fly ash split between the air heater/economizer and the ESP was assumed to be 20:80 and the ash in the air heater/economizer was assumed to contain no mercury due to the high temperature at these locations. Many of the temperatures, pressures and flow rates were acquired during the project from the plant data acquisition systems as shown in Appendix B.

Figure 3.5-58 shows the Hg flow schematic for Endicott. The overall mercury balance, based on total inlet and outlet mercury flow rates, was 105% ($4.80 \text{ g/hr in}/4.56 \text{ g/hr out} * 100\%$) which is very good considering all the assumptions that were made. The overall system removal based on the mercury in the coal and in the stack gas was 78% [$(4.80 \text{ g/hr} - 1.06 \text{ g/hr})/4.80 \text{ g/hr} * 100\%$]. However, there is a discrepancy in that the coal mercury and ash mercury do not equate with the Wet FGD inlet mercury ($4.80 \text{ g/hr} - 1.60 \text{ g/hr} \neq 4.61 \text{ g/hr}$). This demonstrates the difficulty associated with doing this type of analysis and the danger in reading too much into the information. The most important thing to learn from the flow diagram is that, for Endicott, the largest source of mercury entering the system is the coal and that mercury exits the system in about equal parts with the fly ash, stack gas and gypsum.

Figure 3.5-59 shows the Hg flow schematic for Zimmer. The overall mercury balance is fairly good at 83%. However, as with Endicott, the mercury entering the system with the coal does not equate with ash and flue gas mercury values ($63.89 \text{ g/hr} - 0.71 \text{ g/hr} \neq 83.29 \text{ g/hr}$). Calculating the overall system mercury removal based on these numbers does not make sense because the scrubber removal would be much greater than the overall removal. In this instance, it is best to assume that the overall system mercury removal is equal to the scrubber removal since scrubber removal is based on the OH measurements whereas the coal mercury is based on several assumptions about load, flows, etc. Also, since little mercury was measured in the ESP ash, the contribution of the ESP can be ignored. Based on this, the overall system mercury removal for Zimmer was 54% [$(83.29 \text{ g/hr} - 38.2 \text{ g/hr})/83.29 \text{ g/hr} * 100\%$]. More importantly, the schematic shows that, contrary to Endicott, at Zimmer, most of the mercury exits the system with the stack gas and slurry fines. The fly ash and gypsum streams contain little mercury.

Endicott Power Station

Mercury Flow Diagram

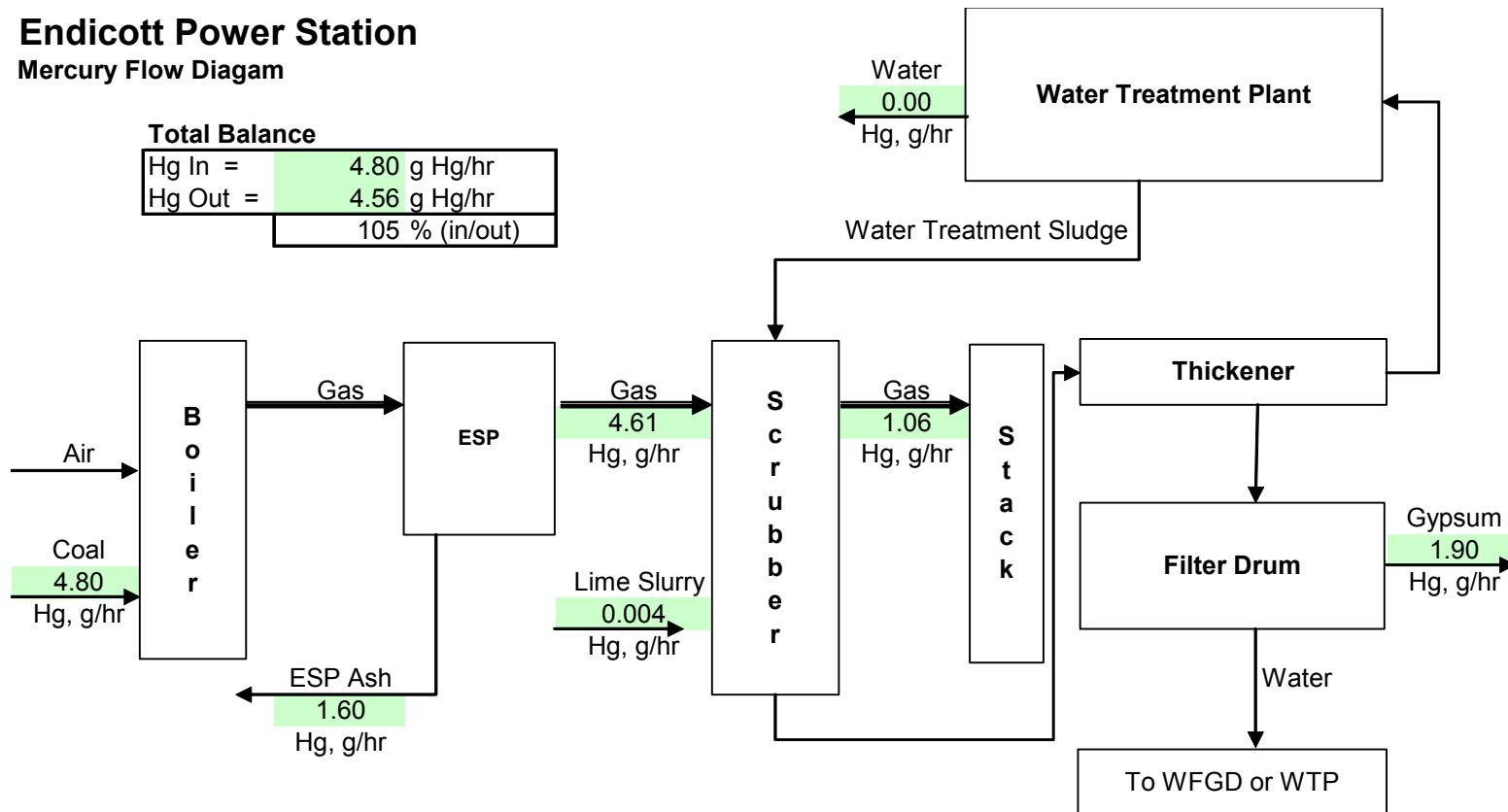


Figure 3.5–58: Hg Flow Schematic for Endicott

Zimmer Power Station

Mercury Flow Diagram

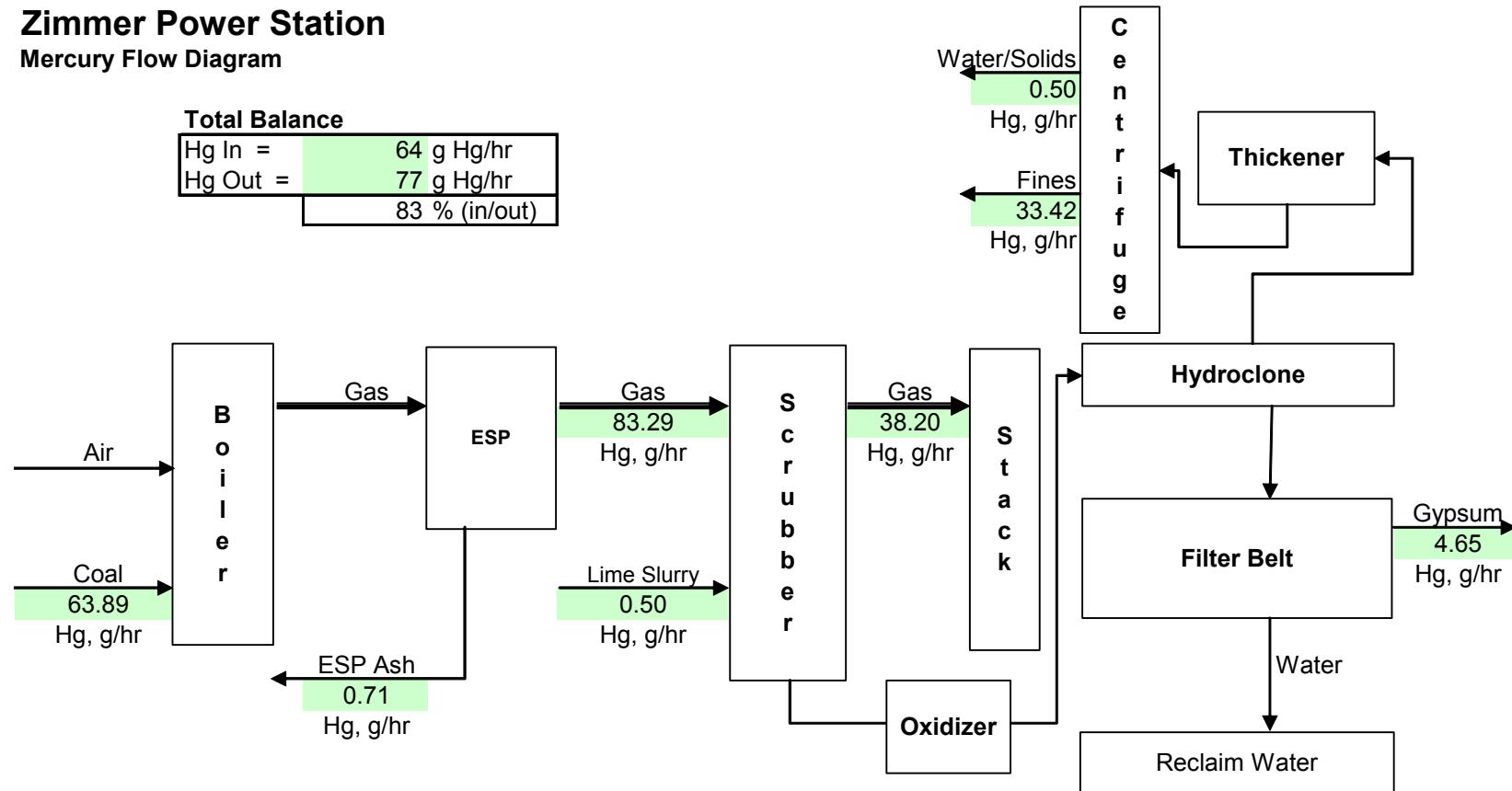


Figure 3.5-59: Hg Flow Schematic for Zimmer

3.5.4 CUBs Results and Conclusions

1. One of the most significant findings of the demonstration is that the mercury in the wet FGD Slurry was associated with the fines. This is significant because the two plants represent opposite ends of the spectrum in plant size and wet scrubber chemistry, and yet both exhibited this behavior, as did the MTI Pilot in previous studies¹. It is also important because the fines can be separated from the larger gypsum crystals through the addition of a variety of commercially available equipment to produce a gypsum product similar to natural gypsum as shown in the table below. The fines can be disposed in standard landfills because the mercury is in a stable form. This finding also suggests that the mercury in wet FGD CUB is not bound to gypsum and may be forming a fine particulate of a pure compound or reacting with some component of the fines, like soot.

	<u>Natural Gypsum</u>	<u>Average FGD Gypsum</u>	<u>Zimmer (w/o fines)</u>	<u>Endicott (with fines)</u>
Minimum:	0.006 ppm (by wt)	0.03	0.03	0.48
Maximum:	0.05 ppm	1.32	0.10	1.15

From EPRI Technical Report² TR-103652

2. The table below shows the averaged mercury concentrations for the major process streams. The important differences include the low mercury content in the Zimmer ESP Ash and Gypsum. The low mercury in the ash may be due to the low amount of unburned carbon in the Zimmer Ash (1%) compared to Endicott Ash (9%). The gypsum has low mercury because it is separated from the fines as part of the process. The fines are not separated at Endicott, so to obtain the value shown below, the fines were separated in the lab. The mercury (and chlorine) in the coal varied by about a factor of three over the course of the test at both sites.

Hg, ppm(dry)	Endicott	Zimmer
Coal	0.21	0.15
ESP Ash	0.32	0.016
Gypsum	0.70	0.055
Wet FGD Slurry	0.76	0.49
Wet FGD Slurry Fines	38 (by TDT)	13.3

3. There was no significant mercury detected in any of the liquid fractions of the CUB, except the Zimmer Centrifuge Water that was not filtered and may have contained fines. This indicates that $HgCl_2$ is not one of the components in CUB because $HgCl_2$ has an appreciable solubility in water.
4. The mercury content of the ESP Ash was not a strong function of ESP Field for the samples that were tested. That is, the mercury was evenly distributed between the fields and did not concentrate with the particulate fines in the latter fields as might be expected. One explanation for this may be that the unburned carbon content in the ash also decreased

in the latter fields at both sites. This would indicate that the unburned carbon is contained in a relatively coarse fraction of the ash or that very little material collected in the latter fields.

5. The Thermal Dissociation Test method using the mercury analyzer appears to be a viable way of detecting small amounts of mercury in CUB. The method produced distinct concentration vs. temperature curves for several pure mercury compounds that correlate well to vapor pressure data for these compounds. However, the curves for HgS and HgO overlap each other which make them indistinguishable. The area under the dissociation curve was shown to be directly proportional to the mercury concentration measured by conventional chemical analysis. Refinements to the technique would require further standard development with other mercury compounds, more tests on a wider range of process samples and the development of a calibration technique for the analyzer.
6. The TDT for all samples showed three distinct sets of peaks clustered around 250, 300 and 400°C. Small differences may be due to changes in argon flow rate, sample boat position, etc., although these were held as constant as possible. The 300°C peak may correspond to HgSO₄ since it only appeared in the dry ash samples and HgSO₄ decomposes in water. The 300°C peak may correspond to HgS or HgO but these cannot be distinguished by this technique. The 250°C peak may be HgCl₂, but it is unlikely since it is water soluble and no mercury was detected in the liquid fractions. It is more likely that this represents a compound that has not yet been tested as a standard.
7. All the CUB tested by TDT were stable below 140°C in that no significant amount of Hg was released at or below 140°C. This is significant because it demonstrates that mercury will not be re-released into the environment through subsequent reprocessing of wet FGD CUB.
8. The TDT for Gypsum from Endicott and Zimmer had similar major peaks at about 250°C with other minor peaks near the major peak. The proportion or composition of the various compounds may be different since the overall curves are distinctly different.
9. The TDT for ESP ash from Endicott had a major peak near 400°C, and ash from the latter fields also had a minor peak near 250°C that indicates a different mercury compound in the particulate fines. The major peak shifted to 300°C after the ash had been mixed with water in the pug mill. This may represent the decomposition of HgSO₄ in water. The Zimmer ESP Ash contained almost no mercury so its TDC was hard to distinguish from the background.
10. The TDT for wet FGD slurry from Endicott and Zimmer produced distinctly different curves. Endicott slurry had a major peak at 300°C and some minor peaks between 300 and 400°C. Zimmer slurry produced a very sharp major peak at 250°C and a distinct minor peak at 400°C. It is interesting to note the after treatment in the *ex situ* oxidation system, the Zimmer gypsum produced a TDC very similar to Endicott suggesting that the chemical composition of the mercury compounds changed in the oxidation process.

11. The TDT for wet FGD slurry fines from Endicott and Zimmer produced nearly identical peaks at about 250°C. The area under the curves, when correlated with conventional mercury analyses, showed that the fines contained the highest mercury concentration of any material yet tested at 38 ppm for Endicott and 13 ppm for Zimmer.
12. By correlating the average mercury concentrations measured in the various streams with the average flow rates of those streams, it was determined that the major source of egress for mercury at Endicott is about equally split between the ESP ash, gypsum and stack gas, whereas the mercury at Zimmer mostly exits via the slurry fines and flue gas.

3.6 QUALITY ASSURANCE/QUALITY CONTROL

General

The objective of the MTI Research and Development Division (R&DD) quality management system is to ensure that the project work meets the intended R&D objective and can be understood and if necessary reproduced successfully by others.

Work performed under this project by MTI was conducted in accordance with the R&DD STANDARD PRACTICE Quality Program. The R&DD STANDARD PRACTICE quality assurance program is well recognized as an outstanding base quality program for research work by such organizations as the U.S. DOE, U.S. DOD, EPRI, Gas Research Institute and many others and is the baseline operating level designation for normal business practices within R&DD. The program is specified in the Quality Management Manual and implemented by the Standard Practice Manual.

The project workscope was defined by way of project planning with the result being an agreement with the customer at the outset of the project. Any changes to the workscope were also agreed upon with the customer. Accordingly, project records were maintained throughout the testing program to provide a historical account of all significant activities. The calibration of all measurement standards and measuring and test equipment used within the R&DD is controlled in order to ensure that measurements made are quantifiable and reproducible in terms of nationally recognized standards.

The Quality Assurance organization exercises general surveillance over projects conducted according to STANDARD PRACTICE. An EPA and an internal audit, conducted to verify the implementation and effectiveness of the internal quality system, were performed during the course of this program; no findings which would affect the quality of the program data were reported.

Project records are available for customer review at the R&DD. The retention of these records is in accordance with MTI policy (minimum five years) or as specified by customer requirements, applicable codes, standards or specifications.

Instrument Calibration

Instrument calibration procedures follow established, documented MTI R&DD Technical Procedures to ensure the sampling and process measurement equipment is functioning properly and the measurements can be traced to a known, defined standard. Instrumentation is generally certified on an annual basis. All of the instrumentation used to acquire test data during this program was required to have current certification. Certified instrumentation included all pressure transmitters, flow meters, dry gas meters, stopwatches and balances. The data acquisition system was certified to assure that the signals from the various instruments were properly transmitted to the storage system. The flue gas analyzers were regularly calibrated using NIST traceable standards throughout the test program.

Sample Custody

The chain of custody for the Ontario Hydro flue gas impinger samples was straightforward and effective. The glassware preparation team signed the glassware set-up data sheets when the sample trains were ready for use. The sampling crew then signed out the impinger train components when they were taken from the laboratory to the sampling site and signed them back in when they were returned to the lab. The sample sheets identified the sampler, sample location, sample method, test ID, filter holder number and glassware set.

Laboratory Analysis

The following methods were used to document the analytical and control procedures used in analysis of samples from operation of the test facility:

- The procedures for the preparation of all reagents and materials that are used for the collection of samples are documented in MTI Technical Procedures based on the EPA and Ontario Hydro Methods. Standardized sample forms are used to document the conditions under which all samples are collected along with identification of the persons responsible for the collection of the samples.
- All field recoveries, extractions, preservations and observations were documented on either a standard form or in a bound laboratory notebook along with identification of the field analyst performing the sample handling.
- Pre-prepared sample container labels were affixed to all collected samples identifying the time, date, sample location, project name, project charge number, sample method, and person responsible for sample recovery. An established laboratory sample numbering and tracking system was used to control the samples. Sample inventory sheets were used to account for the storage of all samples.

The analytical QC effort focuses on ensuring the usefulness of the data generated. Standard EPA or ASTM analytical procedures are followed. The analytical QC procedures include a variety of internal QC checks designed to access and control the data quality as it is generated. The various QC checks, typical frequency and general acceptance criteria are summarized in Table 3.6-1. MDL refers to the method detection limits. The samples are usually analyzed in batches of 10 to 12 samples.

Table 3.6-1: Analytical Quality Control Checks for Trace Metal Analysis

QC Check	Frequency	Acceptance Criteria
Initial Calibration blank & Standards	Once per run	Not applicable
Calibration Verification (AA)	Every hour	$\% D \leq 15\%$
Continuing Calibration Blank	With each calibration	Not applicable
Laboratory Control sample	Once per run	$\% D \leq 20\%$
Matrix Blank	Once / matrix type	Not applicable
Spiked Sample	Once / matrix type	$\% R = 50 - 150\%$

3.7 TECHNICAL CONCLUSIONS

3.7.1 Ontario Hydro Flue Gas Sampling Conclusions

Full-scale field demonstration testing was performed at two power plants to evaluate B&W/MTI's advanced mercury control technology. The Ontario Hydro flue gas sampling method, designed to determine mercury speciation in the flue gas, was used to measure mercury concentration in the flue gas at the inlet and outlet of the wet FGD systems at both plants.

Parametric tests, designed to establish feed rate/performance curves were performed at MSCPAs Endicott station. Based on the results of the Parametric tests, Verification and Long Term tests, designed to show prolonged, reliable mercury removal performance with minimal impact on SO₂ removal performance, were conducted. Average mercury removal across the wet FGD system during the Verification and Long Term tests ranged from 76% to 79%. Most of the oxidized mercury present in the flue gas was removed in the wet FGD system; no increase in

elemental mercury concentration was observed during the Endicott testing, indicating that the control technology was successful in not only maintaining high oxidized mercury removal but simultaneously suppressing mercury reemission.

Following the Endicott test program, two weeks of Verification tests were performed at Cinergy's Zimmer station. Mercury removal across the wet FGD system during these tests averaged 51%. Compared to the Endicott results, lower oxidized mercury removal performance was observed at Zimmer (87% vs. 96%). In addition, elemental mercury concentrations increased across the wet FGD system, indicating that the control technology was not effective in suppressing the reemission of captured mercury from the scrubber. Testing conducted with 50% more reagent feed at the end of the Zimmer test program showed no improvement in mercury removal performance.

At both power plants, the wet FGD systems were very effective in removing oxidized mercury from the flue gas entering the scrubber. Total wet FGD mercury removal performance, however, was limited by the amount of elemental mercury present in the inlet flue gas. A comparison of various technical scenarios illustrated the importance of a viable mercury oxidation technology in obtaining high total wet FGD mercury removals. In one example (75% oxidized, 25% elemental entering a wet FGD system), combining a viable oxidation technology with B&W/MTI's control technology could improve mercury removal to 91%; by comparison, either technology by itself yielded a maximum removal of 78%.

3.7.2 Mercury in Coal Utilization By-Products Conclusions

One of the most significant findings of the demonstration is that the mercury in the wet FGD Slurry was associated with the fines. This is significant because the two plants represent opposite ends of the spectrum in plant size and wet scrubber chemistry, and yet both exhibited this behavior, as did the MTI Pilot in previous studies¹. It is also important because the fines can easily be separated from the larger gypsum crystals through the addition of a variety of commercially available equipment to produce a gypsum product similar to natural gypsum as shown in the table below. The fines can be disposed of in standard landfills because the mercury is in a stable form. This finding also suggests that the mercury in wet FGD CUB is not bound to gypsum and may be forming a fine particulate of a pure compound or reacting with some component of the fines, like soot.

	<u>Natural Gypsum</u>	<u>Average FGD Gypsum</u>	<u>Zimmer (w/o fines)</u>	<u>Endicott (with fines)</u>
Minimum:	0.006 ppm (by wt)	0.03	0.03	0.48
Maximum:	0.05 ppm	1.32	0.10	1.15

From EPRI Technical Report² TR-103652

The table below shows the averaged mercury concentrations for the major process streams. The important differences include the low mercury content in the Zimmer ESP Ash and Gypsum. The low mercury in the ash may be due to the low amount of unburned carbon in the Zimmer Ash (1%) compared to Endicott Ash (9%). The gypsum has low mercury because it is separated

from the fines as part of the process. The fines are not separated at Endicott, so to obtain the value shown below, the fines were separated in the lab. The mercury in the coal varied by about a factor of three over the course of the test at both sites.

Hg, ppm(dry)	Endicott	Zimmer
Coal	0.21	0.15
ESP Ash	0.32	0.016
Gypsum	0.70	0.055
Wet FGD Slurry	0.76	0.49
Wet FGD Slurry Fines	38 (by TDT)	13.3

4.0 MARKETING/COMMERCIALIZATION DISCUSSION

4.1 MARKET APPLICATION

Current Status

The current U.S. coal-fired utility industry has approximately 307,000 MW of electrical capacity. Table 4.1-1 breaks down the total capacity into scrubbed (equipped with some type of SO₂ control equipment) and unscrubbed (no SO₂ control equipment) markets. Figure 4.1-1 further breaks the wet scrubbing market into groups according to scrubbing reagent used.

Table 4.1-1: U.S. Coal-fired Utility Industry Scrubbed and Unscrubbed Markets

Total Coal-Fired Utility Industry: 307,000 MW	
Scrubbed Market: 92,600 MW	Unscrubbed Market: 214,000 MW
Wet: 80,640 MW	Dry: 11,960 MW

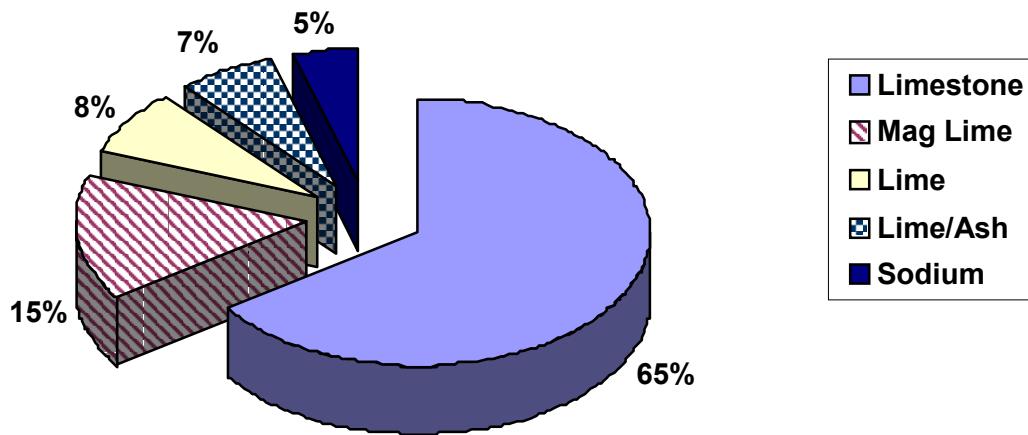


Figure 4.1-1: Wet Scrubber Market by Reagent Type

Based on the data in Table 4.1-1, approximately 25% of the U.S. generating capacity is equipped with wet FGD pollution control equipment. To date, the mercury control process utilized during this program has only been evaluated on wet scrubber-based FGD systems; it is unknown whether dry FGD mercury removal performance would be enhanced. Based on the modeling efforts described below, applying B&W/MTI's wet scrubber-based enhancement technology to all existing wet FGD systems would reduce yearly U.S. Hg emissions by approximately 6 tons.

Future Impact

B&W previously developed a model of the impact of enhanced wet FGD mercury emissions control based on a detailed coal-fired utility database, data from US EPA's ICR effort and published emission factors, and data obtained during the mercury control technology evaluation testing conducted during that program. Estimates of the potential impact of B&W/MTI's wet scrubber enhancement technologies on current coal-fired utility mercury emissions were made based on updated wet FGD removal performance from the current demonstration program. These estimates also show the impact of improving the amount of oxidized mercury present in the flue gas. This is an important consideration for applying mercury control technologies because oxidized mercury is much more readily removed from the flue gas than is elemental mercury. In addition, some types of coal (most notably Powder River Basin and other sub-bituminous coals) can yield substantial amounts of elemental mercury which leave the stack essentially uncontrolled, regardless of what type of traditional pollution control equipment is installed.

A summary of the current U.S. coal-fired utility market is shown in Table 4.1-2. The market is arranged by geographic location (east or west of the Mississippi River), coal type, FGD type (if applicable), and particulate control device (PCD). The categorical breakdowns are based on EPA-supplied data available from their Web site. The six highlighted rows correspond to the six largest categories within the U.S. utility market and represent 85% of the total generating capacity. The various Hg removal impact scenario calculations in the following discussion are based only on these six categories.

Three Hg removal impact scenarios are shown in the table and represent the following:

- **Current:** The amount of mercury removal currently achieved for the various categories with existing pollution control equipment.
- **Enhanced w/o Oxidation:** The amount of mercury removal possible with the application of B&W/MTI's wet FGD control technology to units currently equipped with wet FGD systems (activated carbon injection (ACI) control is assumed for unscrubbed units).
- **Enhanced w/ Oxidation:** The amount of mercury removal possible with the application of the control technologies mentioned above *plus* the application of a technology capable of oxidizing 80% of the elemental mercury *present in the flue gas*. This technology would be applied upstream of any pollution control equipment or any mercury control technology.

For each of the three scenarios, a weighted removal average (and corresponding estimated emission rate) is calculated based on the installed generating capacity for each of the included categories. For example, the "Current" weighted removal average is 35% resulting in an estimated emission rate of 54 tons Hg/year, which agrees well with the generally reported rate of 50 to 55 tons Hg/year. The scenarios also assume that no fuel switching occurs.

Table 4.1-2: U.S. Coal-fired Generating Market Summary

Location	Coal Type	FGD Type	PCD Type	MW	% of Total MW	Hg Removal Impact Scenarios		
						Current	Enhanced w/o Hg ^o Oxidation	Enhanced w/ Hg ^o Oxidation
Scrubbed Units								
East	Bit	Wet	ESP	39,345	12.8	63%	80%	92%
East	Bit	Wet	Other	3,496	1.1			
East	Bit	Dry	ESP	160	0.1			
East	Bit	Dry	Other	3,017	1.0			
East	Sub	Wet	ESP	1,954	0.6			
East	Sub	Wet	Other	44	0.0			
West	Bit	Wet	ESP	2,305	0.8			
West	Bit	Wet	Other	1,498	0.5			
West	Bit	Dry	Other	1,256	0.4			
West	Sub	Wet	ESP	13,412	4.4	57%	72%	91%
West	Sub	Wet	Other	9,867	3.2	57%	72%	91%
West	Sub	Dry	ESP	1,562	0.5			
West	Sub	Dry	Other	4,588	1.5			
West	Lig	Wet	ESP	8,726	2.8			
West	Lig	Dry	Other	1,380	0.4			
<i>Scrubbed Totals</i>				92,610				
<i>Unscrubbed Units</i>								
East	Bit	NA	ESP	109,659	35.7	18%	66%	79%
East	Bit	NA	Other	2,974	1.0			
East	Sub	NA	ESP	45,431	14.8	39%	63%	82%
East	Sub	NA	Other	1,807	0.6			
West	Bit	NA	ESP	2,438	0.8			
West	Bit	NA	Other	864	0.3			
West	Sub	NA	ESP	40,858	13.3	39%	63%	82%
West	Sub	NA	Other	6,795	2.2			
West	Lig	NA	ESP	1,031	0.3			
West	Lig	NA	Other	2,430	0.8			
<i>Uncrubbbed Totals</i>				214,287		Weighted Averages		
	<i>U.S. Totals</i>			306,897		35%	68%	83%
Estimated Emission Rates, ton/yr								
						53.8	26.9	14.2

The results presented in Table 4.1-2 illustrate several key considerations for improving Hg removal performance for coal-fired utilities:

- Two-thirds of the current U.S. generating capacity is supplied by ESP-equipped bituminous-fired and ESP-equipped sub-bituminous-fired units. Improved Hg control for these units will have a major impact on the nationwide emissions rate.

- Applying B&W/MTI's enhancement technologies to both scrubbed and unscrubbed units results in a 50% decrease in the emissions rate, from 54 tons/yr to 27 tons/yr.
- Combining B&W/MTI's control technologies with an oxidation technology capable of oxidizing 80% of the elemental Hg present in the flue gas results in a further reduction of 50%, down to 14 tons/yr. This reduction is due primarily to the conversion (and capture) of the significant amount of elemental mercury generated by the sub-bituminous-fired units.
- Even with the high levels of oxidized mercury generated in the oxidation-based scenario, ACI typically removes less Hg than wet scrubbing.

Table 4.1-3 further illustrates the necessity of Hg oxidation technologies for high levels of Hg removal (on a national scale). In the table, the results of the three scenarios above are repeated, in addition to two additional scenarios (again, no fuel switching is assumed):

- **All Enhanced Wet FGD w/o Oxidation:** In this scenario, all units are equipped with wet FGD systems utilizing B&W/MTI's enhanced control technology (no sorbent injection) *but no oxidation technology for converting elemental mercury*.
- **All Enhanced Wet FGD w/ Oxidation:** In this scenario, all units are equipped with wet FGD systems utilizing B&W/MTI's enhanced control technology (no sorbent injection) *plus* an oxidation technology capable of converting 80% of the elemental mercury present in the flue gas to oxidized mercury.

Table 4.1-3: Impact of Elemental Hg Oxidation

Scenario Number	1	2	3	4	5
	Current	Enhanced w/o Hg° Oxidation	Enhanced w/ Hg° Oxidation	All E-wet FGD w/o Hg° Oxidation	All E-wet FGD w/ Hg° Oxidation
Weighted Averages	35%	68%	83%	76%	92%
Estimated Emission Rate, tons/yr	53.8	26.9	14.2	19.6	6.7

The results shown in Table 4.1-3 indicate that utilizing enhanced wet scrubber control for all units without an oxidizing technology (scenario 4) yields higher mercury removals, 76% vs. 68% (a 7 ton/yr improvement), than the combination of sorbent injection for unscrubbed units and enhanced wet scrubber control for currently scrubbed units (scenario 2). It can also be seen that mercury removal can be dramatically increased with the addition of an oxidizing technology (scenarios 2 vs. 3 and 4 vs. 5). The emission rate for scenario 5 is equivalent to a plant removal

rate (from as-fired coal to stack) of 92%, compared to a plant removal rate of 76% in the absence of an oxidation technology.

Comparison with Competing Technologies

To date, the most extensive mercury control research has been related to mercury capture via sorbent injection (either alkali-based or carbon-based). Most of the pilot- and demonstration-scale test programs have focused on the use of activated carbon injection (ACI) as the technology of choice for mercury control. This section compares the latest published mercury removal/cost information^{3,4,5} for ACI with B&W/MTI's enhanced wet FGD-based process for a variety of scenarios. For the purposes of this discussion, the B&W/MTI process will be referred to as "E-Hg". For all scenarios, particulate control is performed by an existing ESP.

For each scenario, annual leveled costs (ALC) were calculated based on published removal/cost data for ACI and cost estimate modeling for E-Hg. For a more detailed discussion of how ALC values were determined, please see Section 4.5 – Process Economics. The following operational assumptions were made when performing the cost calculations:

Size of Plant:	500 MW
Capacity Factor:	65%
Coal S:	3%, 1%, 0.3%
Coal Hg:	0.23 ppm
Cost of carbon:	\$0.425/lb
Carbon feedrate:	5000:1, 9000:1, 15,000:1 lb AC/lb Hg
Target Hg Removal:	80%
Base Wet FGD Hg Removal:	70%

Scenario 1: Existing Wet FGD + E-Hg vs. ACI

Intended to represent the most likely initial target base for E-Hg, the model plant is firing a 3% sulfur coal and is equipped with a wet FGD system. Table 4.1-4 summarizes the results of the analysis and provides the estimated capital, operating and maintenance (O&M) costs both for applying B&W/MTI's enhancement process to an existing wet FGD system, and for installing a new wet FGD system with the enhancement process. Reagent cost is the majority of the O&M costs. The table also includes what might be considered an equivalent evaluation using ACI technology solely for mercury capture at the 60 and 70 percent removal levels. Direct comparison of enhancement in an FGD system with ACI technology is difficult to establish given the fact that potential applications for each do not lend themselves to a direct comparison. Nevertheless, the incremental cost difference between the 60 and 70 percent removals with ACI may establish a better way to evaluate the relative cost benefit associated with improving mercury capture with the additive enhancement in a wet FGD system. Although it is highly unlikely that ACI would be used in a situation where the existing wet FGD system is already providing 70 percent removal, the 0.18 mil/kWh annual leveled cost of improving this to 80 percent with the additive technology is substantially below the 0.80 mil/kWh cost differential between achieving 60 and 70 percent removal with ACI. This is thought to illustrate the fact that enhanced mercury capture on its own represents minimal additional expense for scrubber-

equipped utilities interest in reducing their mercury emissions and assuring that the mercury captured will be retained within the system rather than being re-emitted in the elemental form.

While the values presented for ACI control are based on B&W/MTI's own analysis of the cost of providing and operating an injection system, there are both positive and negative differences between the relative costs of capital and operating costs when compared to some of those reported by others. Because these differences are still being reconciled, no breakdown is provided on the capital and operating costs at this time. There is general agreement, however, between the costs developed here and the \$2 – 5 million/yr range of overall annual leveled costs being reported by those working more directly on ACI control technologies.^{3,4,5}

Table 4.1-4: Costs of Mercury Removal Processes

ENHANCED MERCURY CAPTURE IN A WET FGD SYSTEM	Existing 500 MW Installation	New 500 MW Installation
Total Capital Requirement, \$	3,000,000	63,000,000
Total System O&M Costs, \$/yr	125,000	3,200,000
Annual Levelized Cost, \$/yr	500,000	12,000,000
Annual Levelized Cost, mil/kWh	0.18	4.23
MERCURY CAPTURE WITH ACI TECHNOLOGY	@ 60% Removal	@ 70% Removal
Annual Levelized Cost, \$/yr	2,400,000	4,700,000
Annual Levelized Cost, mil/kWh	0.85	1.65

The application of the B&W/MTI enhanced mercury capture process with a wet FGD system has the additional benefit of having virtually no impact on scrubber operation and gypsum quality. Moreover, it does not adversely affect the acceptability of fly ash for disposal/sale, a potential drawback ACI may have if it is not practical or economically attractive to separate by-product fly ash from the spent activated carbon. This aspect came to light in the demonstration of ACI at Wisconsin Electric's Pleasant Prairie Power Plant where the carbon appeared to negate its use as a cement admixture. The economic impact in this case was estimated to be \$12 to \$15 million/yr due to lost fly ash sale revenue and increased landfill disposal costs.⁴

Scenario 2: New Wet FGD + E-Hg vs. ACI + Spray Dryer Absorber (SDA)

As further reductions in U.S. SO₂ emissions become more likely to be enacted (see ‘Market Issues’ below), the installation of additional FGD capacity becomes more likely. In effect, the ‘threshold’ coal sulfur level, above which some type of FGD system would be required, would continue to decrease. As a result, new FGD systems would, in more and more cases, become financially attractive as the amount of ultra-low-sulfur coal would continue to decrease (and demand increase). In some instances, especially for units already firing lower sulfur coals, spray dryer absorbers (SDA) tend to be favored over wet FGD systems. If mercury control legislation is enacted in conjunction with more stringent SO₂ emissions requirements, however, the choice of equipment becomes more intriguing. This scenario represents a potentially significant portion of the current U.S. generating market. For example, focusing solely on unscrubbed, ESP-equipped units east of the Mississippi firing bituminous coals encompasses 109,000 MW, one-third of the current generating capacity in the US.

In this scenario, a low-sulfur coal (1%) is being fired in the 500 MW model plant. For the ACI + SDA options, it has been assumed that the addition of the SDA system will result in Hg removal performance comparable to wet FGD. In Table 4.1-5, the ALC (expressed in mil/kWh and \$/yr) are shown for this comparison.

Table 4.1-5: Comparison of Wet FGD + E-Hg vs. ACI + SDA

ALC	Wet FGD @ 70%	Wet FGD + E-Hg @ 80%	ACI + SDA @ 70%	ACI + SDA @ 80%
mil/kWh	4.05	4.23	4.11	4.59
\$/yr, 000's	11,559	12,063	11,720	13,090
mil/kWh Δ, 70% to 80%		0.18	--	0.48
\$/yr, 000's Δ, 70% to 80%		504	--	1,370

The results shown in Table 4.1-5 illustrate two interesting observations. First and foremost, the addition of a wet FGD system (with or without E-Hg) for combined SO₂ and Hg control is economically competitive with similarly performing ACI + SDA systems. Factoring in potential operational cost increases such as the ash disposal concerns mentioned in Scenario 1, and the application of a wet FGD-based system becomes even more attractive. Secondly, increasing the Hg removal performance for the wet FGD-based system through the addition of E-Hg is significantly less expensive than increasing the carbon feed rate to achieve the same performance for the ACI + SDA system.

Scenario 3: New Wet FGD + E-Hg vs. ACI

In some instances (ultra low-sulfur coal, SO₂ credit surplus), more stringent SO₂ emissions regulations will not require utilities to install new FGD control equipment. Any new equipment would be installed primarily for Hg control. For this scenario a very low-sulfur coal (0.3%) is being fired in the 500 MW model plant. Because a large portion of these low-sulfur coals are of the Western sub-bituminous variety, a much larger percentage of the mercury present in the flue

gas is in the elemental form, which is not readily removed by wet FGD systems. Removal performance for the wet FGD estimates have been lowered to reflect an assumed 50:50 split between oxidized and elemental mercury (this does not affect wet FGD costs, only the corresponding ACI system). Similar to Scenario 2, this type of plant (low-sulfur, sub-bituminous coal, non-scrubbed, ESP-equipped) represents a potentially significant portion of the U.S. generating market (86,000 MW). In Table 4.1-6, the ALC (expressed in mil/kWh and \$/yr) are shown for this comparison, along with estimated values for SO₂ credits from the installation of a new wet FGD system (based on \$150/ton SO₂).

Table 4.1-6: Comparison of Wet FGD + E-Hg vs. ACI

ALC	Wet FGD @ 50%	Wet FGD + E-Hg @ 60%	ACI @ 60%
mil/kWh	4.05	4.23	0.85
\$/yr, 000's	11,559	12,063	2,426
SO ₂ credit, \$/yr 000's	946	946	--

Given the significant capital requirement for wet FGD systems, it is not surprising that installing these systems solely for Hg control will not generally be economically viable. Only in those situations where an increase in carbon content in the fly ash would result in significant operating cost increases (higher disposal costs, loss of by-product sale, etc.) would it potentially become attractive to install wet FGD for Hg control.

4.2 BY-PRODUCT MARKET

An important consideration for a successful mercury control technology is that of waste generation. Additionally, for mercury control processes which are “add-ons” to existing pollution control processes (i.e. wet FGD), minimizing the effect on usable by-products is highly desirable. The reagent used during this program is fed to the wet scrubber in very small amounts. The feed rates were approximately 1 gallon/hour at Endicott (55 MWe) and 5.4 gallon/hour per absorber at Zimmer (5 operating absorbers, 1300 MWe) and does not accumulate in the slurry. Excess reagent reacts with other constituents in the slurry or is volatilized and exits with the flue gas. This reagent also does not affect slurry quality or the SO₂ removal performance of the scrubber system.

The only by-product potentially formed by this process would be generated from the additional capture of mercury (above baseline removal performance). During this program, various process samples were analyzed in an attempt to identify mercury compounds formed in the scrubber and to determine their stability. The results of this work indicated that 1) all mercury compounds formed through this process are essentially insoluble and are thermally stable over the temperature range of typical wallboard manufacturing processes, and 2) the mercury captured in the wet scrubber is present as a fine particulate; the use of blowdown and other purge streams containing fine particulate can effectively maintain low Hg concentrations in the scrubber

gypsum by-product. In addition, even with the increased mercury removal performance achieved by this process, the disposal status of the gypsum generated in the scrubber is not adversely affected. These points are discussed in more detail in Section 3.5.

4.3 MARKETPLACE ACCEPTANCE

Potential barriers to commercial application of B&W/MTI's enhanced mercury control technology may be classified as technical, market, or regulatory. Although several potential obstacles will be discussed, no one single concern is expected to prevent commercial application of the technology. Conversely, because mercury emissions from coal-fired boilers are currently not regulated (with the exception of a couple of pending state requirements), utilities are not likely to install any control equipment until some indication of control requirements and corresponding timeframe for compliance is available.

Technical Issues

The control technology demonstrated during this program represents a low-cost, non-intrusive method of enhancing mercury removal performance for wet FGD-equipped utility power plants. Because it relies on the presence of a wet FGD system, however, initial applications of the technology will be limited to 1) those units currently equipped with a wet FGD system, and 2) new wet FGD construction. Additionally, mercury removal performance results from this program have identified a number of potential technical limitations and uncertainties which will need to be addressed prior to successful market application. These include:

- **Impact of Hg speciation** – Mercury in the oxidized form is readily captured by wet FGD systems; elemental mercury is essentially unaffected. As a result, the ratio of the oxidized:elemental mercury entering a utility wet FGD system will have a direct impact on the upper removal performance limit of the control technology. For bituminous-fired units with unusually low concentrations of oxidized mercury, or for units firing sub-bituminous coals, which typically generate high percentages of elemental mercury, additional processes or technologies which improve mercury oxidation may be required should mercury control regulations stipulate high removal levels.
- **Impact of Wet FGD chemistry** – During this program, two different scrubber chemistries were encountered: the Endicott wet FGD system is limestone-based with *in situ* forced oxidation (LSFO); the Zimmer wet FGD system is Thiosorbic® Lime-based with natural oxidation in the scrubber and *ex situ* forced oxidation system for gypsum production. As mentioned in Section 3, this difference was not expected to have an impact on mercury removal performance; the test results indicated otherwise. Because all of the development work on this technology (and 1 of the 2 demonstration tests) was performed with limestone-based, *in situ* forced oxidation systems, it is uncertain how well it will perform in scrubber systems based on different chemical processes. Currently, one-third of the wet scrubber-equipped U.S. generating capacity (approx. 27,000 MW) is utilizing non-LSFO chemistry scrubber systems (although LSFO FGD and dry FGD are expected to become the technologies of choice and increase their market share).

- **Concentration of Captured Mercury** – As shown in Section 3.5, the mercury captured in an enhanced wet FGD system tends to be present as a fine particulate. As such, in unit operations such as hydroclone separation, the mercury will preferentially report to the dilute phase. This behavior serves to not only minimize the amount of mercury reporting to the gypsum, but offers the potential for reduced waste treatment costs by concentrating the captured mercury in a single stream (e.g., blowdown or purge stream).

Market Issues

The widespread acceptance and application of mercury control technologies (in general) will quite likely be highly dependent upon other pollutant emission requirements. Several recent trends indicate an increased potential for long-term application of B&W/MTI's enhancement process:

- **Increased trend toward scrubbing vs. coal switching** – A resurgence of demand for FGD systems is expected not only because emissions regulations are becoming more stringent but also because banked SO₂ allowances resulting from the 1990 Clean Air Act are rapidly being depleted. The requirement of FGD, especially in the eastern U.S., will cause a re-evaluation of fuel type versus cost and should result in some fuel switching back to higher sulfur, lower cost eastern fuels for units that previously switched to low-sulfur fuels to avoid scrubbing. The higher sulfur fuels coupled with increased SO₃ emissions aggravated by SCR (selective catalytic reduction) installations will pose the problem of visible sulfuric acid plumes.
- **Interaction with other pollution control processes** – The release of the NOx SIP call requires the reduction of NOx emissions, primarily via SCR, for the 24 states east of the Mississippi River. Coincidentally, this same region is where most of the high sulfur coal is fired in the U.S. Compliance with the SIP call is well underway; numerous new SCR installations are online or in the planning stages. Initial research into the effect of SCR catalysts on mercury speciation has shown that, in some instances, significant oxidation of elemental mercury is observed. Since SCRs are installed upstream of wet FGD systems, any increase in the percentage of oxidized mercury in the flue gas will improve the removal performance for the wet FGD system.

Regulatory Issues

With the exception of Wisconsin (and more recently, North Carolina), mercury emission control requirements at the federal and state level have not yet been promulgated. Because of the demonstrated technology's reliance on wet FGD systems, however, developments in SOx (and to a lesser extent, NOx) emission regulations could have an impact on the extent and timing of market application.

Recent federal regulatory developments indicate that further reductions in NOx and SOx emissions are under increased scrutiny. The Jefford's Bill, which calls for significant further reductions of SOx (72%), NOx (75%) and mercury (90%) emissions, was recently approved in committee hearings. Although it is questionable whether the Bill will pass in its current form, its

successful committee discussion indicates that utility-generated pollution levels are foremost in Federal discussions. It is currently anticipated that some form of this Bill will supplant the New Source Review Requirements of the CAAA of 1990.

From a state regulatory viewpoint, many states, such as Massachusetts, New Hampshire, Connecticut and more recently North Carolina are seeking to clean up coal-fired units by imposing emissions regulations that are often more stringent than federal regulations rather than seeking ways to replace coal. In some instances, these state requirements are incorporating Hg emission control requirements, *in addition to* NOx and SOx emission reductions.

4.4 INCREASED USE OF OHIO COAL

According to utility plant data available from the US EPA, approximately 7,600 MW (31 units) of installed generating capacity is currently firing Ohio coal. Of that amount, approximately 4,300 MW (8 units) is scrubbed. Of the 7,600 MW burning Ohio coal, 5,300 MW (3,600 MW scrubbed) is located in the state of Ohio. Total installed generating capacity in the state of Ohio is 23,300 MW. Table 4.4-1 presents a summary of this data, along with related percentage calculations regarding the current use of Ohio coal.

Table 4.4-1: Current Status of Ohio Coal Use and Ohio Generating Capacity

	Total	Wet FGD	Percentage
Ohio Generating Capacity, MW	23,300	5,000	21%
- firing Ohio coal	5,300	3,600	68%
Percent of Ohio Total	23%	72%	
US Generating Capacity, MW	307,000	80,600	26%
- firing Ohio coal	7,600	4,300	57%
Percent of US Total	2.5%	5.3%	

Based on the numbers provided in Table 4.6, the most likely source of increased Ohio coal usage is within the state of Ohio. Only 23% of the generating capacity is fired by Ohio coal, most likely due to emission restrictions. Furthermore, some of the scrubbed generating capacity is currently fired by non-Ohio coal (1,400 MW).

4.5 PROCESS ECONOMICS

In section 4.1, annual levelized costs (ALC) were estimated for several scenarios. This section provides additional information regarding the calculation of the values presented in each scenario. Each ALC was calculated based on a Total Capital requirement, distributed over a 20 year life, plus yearly operating and maintenance costs. EPRI's (Electric Power Research Institute) TAGTM *Technical Assessment Guide* (EPRI Report P-6587-L) was used as the basis for the calculations. The starting point for the Total Capital requirement was the installed equipment cost – all other capital/investment costs were determined by applying factors to the installed equipment cost. Included as other capital/investment costs were engineering, general facilities,

project contingency, process contingency, pre-production costs, and inventory costs. Yearly operating costs included the additive and water costs, as well as a substantial carrying charge. Since existing Plant Operations personnel could assume the duties of operating and monitoring the B&W/MTI system, the associated costs for additional operating labor or administration/overhead were assumed to be negligible for the purposes of this analysis.

Operational assumptions for the comparison scenarios included:

- Plant Size: 500 MW, 65% capacity factor
- Coal Hg Concentration: 0.23 ppm
- Base Hg Removal in Scrubber: 70%

Table 4.5-1 summarizes the estimated capital, operating and maintenance (O&M) costs for applying B&W/MTI's enhancement process to an existing wet FGD system and for installing a new wet FGD system with the enhancement process.

Table 4.5-1: Summary of Costs for 500 MW E – Hg Process

	E – Hg, 500 MW	Wet FGD + E – Hg, 500 MW
Total Capital Requirement, \$ 000's	2,701	62,701
Total O&M Costs, \$ 000's/yr	128	3,219
ALC, \$ 000's/yr	504	12,063
ALC, mil/kWh	0.18	4.23

4.6 COMMERCIALIZATION PLAN

The commercialization plans presented here represent a current assessment of appropriate market entry and business development activities. These plans are not final and will change as business and market conditions change. The inclusion of these plans should not be construed as a commitment to proceed as specifically discussed here. Babcock & Wilcox retains the right to make changes in these plans at any time as market and business conditions change.

Babcock & Wilcox is committed to developing and supplying wet FGD-based mercury emissions control technology. The system enhancements for increased mercury removal demonstrated during this program provide a distinct marketing advantage. B&W has made, and will continue to make, a significant investment in the development of the technology to the point of commercial feasibility.

The enhanced wet FGD approach provides several distinct and unique advantages over other developing mercury emissions control technologies including:

- Commercially proven and accepted base technology with extensive operating history and established system suppliers.

- Established by-product market for FGD gypsum.
- Limited additional hardware
- Simple operation
- Lower operating costs than alternatives in many situations
- Readily available reagent with established suppliers with *existing* production capacity.

All of the above factors make B&W/MTI's process an attractive option for enhancing mercury control performance for wet FGD systems. Until regulations governing mercury emissions levels are issued, however, the extent to which this, or any, control process will be implemented will be minimal. As mentioned above, several emerging trends in the environmental emissions control market, however, may have a favorable impact on commercialization of B&W/MTI's process. Some of these current favorable trends include:

- Multi-pollutant emissions regulation potential
- States moving forward to address mercury control in phased approach: allowing FGD only to meet initial near-term requirements; B&W's enhancements would be used to increase removal as needed to meet later requirements – 10 to 15 years out.
- NSR pushing potential wet FGD market
- Increasing preference to scrub over fuel switching

5.0 REFERENCES

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Appendix A – Proximate Analyses for Zimmer Coal Samples

Fuels Activity Management System Coal Calculation Detail Report Cincinnati Gas & Electric, W.H. Zimmer

10/23/2001 - 11/06/2001

<u>Date</u>	<u>Source</u>	<u>Ash Dry (%)</u>	<u>Moisture (%)</u>	<u>Sulfur Dry (%)</u>	<u>Heat Val Received (Btu/lb)</u>	<u>Sulfur (lb/MMBtu)</u>	<u>Unit 1 Bunker (Tons)</u>	<u>Distribution Total</u>
10/23/01	OR 3649	9.67	11.19	3.84	11,565.00	5.90	1,530.70	1,530.70
10/23/01	OR 3698	12.04	13.02	3.18	10,863.00	5.09	1,546.40	1,546.40
10/23/01	OR4755	9.54	13.52	4.11	11,144.00	6.38	1,732.80	1,732.80
10/23/01	OR 4772	10.58	12.34	3.38	11,226.00	5.28	1,617.00	1,617.00
10/23/01	OR 5400	10.21	9.05	3.80	11,919.00	5.80	495.30	495.30
10/23/01	OR 6679	9.75	6.68	4.19	12,492.00	6.26	1,792.70	1,792.70
+10/23/01	OR 7005	14.39	6.96	3.56	11,648.00	5.69	1,804.71	1,804.71
10/23/01	T13615B	9.49	7.11	4.23	12,447.00	6.31	1,400.00	1,400.00
10/24/01	OR 1043	9.10	9.62	4.07	12,160.00	6.05	1,776.00	1,776.00
10/24/01	OR 4751	10.25	11.78	3.55	11,285.00	5.55	156.20	156.20
10/24/01	OR 4808	11.87	13.02	3.80	10,952.00	6.04	1,741.40	1,741.40
10/24/01	OR 4945	11.45	9.40	4.64	11,892.00	7.07	1,895.50	1,895.50
10/24/01	OR 5265	10.61	14.65	3.67	10,879.00	5.76	1,725.50	1,725.50
10/24/01	OR 5521	11.97	11.89	3.79	11,156.00	5.99	289.80	289.80
10/24/01	T13593B	11.72	7.38	4.48	12,095.00	6.86	1,973.20	1,973.20
10/24/01	T13607B	12.84	6.72	4.87	11,953.00	7.60	1,161.40	1,161.40
10/24/01	T13615B	9.49	7.11	4.23	12,447.00	6.31	604.00	604.00
10/25/01	OR 1196	9.52	7.60	4.32	12,387.00	6.44	1,805.80	1,805.80
10/25/01	OR 1204	9.60	6.16	4.31	12,578.00	6.43	1,713.00	1,713.00
10/25/01	OR 4856	10.09	7.20	4.25	12,319.00	6.40	1,871.60	1,871.60
10/25/01	OR 5194	10.27	7.27	4.35	12,307.00	6.56	1,777.60	1,777.60
10/25/01	OR 5215	9.84	8.01	4.47	12,274.00	6.70	1,745.20	1,745.20
10/25/01	OT013B	9.80	5.89	4.39	12,577.00	6.57	1,656.00	1,656.00
10/25/01	T13578B	10.67	6.45	4.30	12,345.00	6.52	732.70	732.70

Note: '+' Indicates that a Station Payment Quality Analysis was not found for one or more distributions.

Note: '*' Indicates that no Station Quality Analysis was found for one or more distributions.

Fuels Activity Management System
Coal Calculation Detail Report
Cincinnati Gas & Electric, W.H. Zimmer

10/23/2001 - 11/06/2001

<u>Date</u>	<u>Source</u>	<u>Ash Dry (%)</u>	<u>Moisture (%)</u>	<u>Sulfur Dry (%)</u>	<u>Heat Val Received (Btu/lb)</u>	<u>Unit 1 Sulfur (lb/MMBtu)</u>	<u>Bunker (Tons)</u>	<u>Distribution Total</u>
10/25/01	T13607B	12.84	6.72	4.87	11,953.00	7.60	816.50	816.50
10/26/01	OR3762	9.50	6.82	4.13	12,483.00	6.17	1,707.00	1,707.00
10/26/01	OR 4840	11.69	7.61	3.07	12,208.00	4.65	957.20	957.20
10/26/01	OR5210	9.28	6.74	4.23	12,462.00	6.33	1,125.00	1,125.00
10/26/01	OR 5349	9.06	6.24	4.17	12,634.00	6.19	1,840.80	1,840.80
10/26/01	OR 5389	9.57	7.16	4.00	12,456.00	5.96	1,856.70	1,856.70
10/26/01	OR 5404	9.98	6.63	4.44	12,405.00	6.68	1,200.30	1,200.30
10/26/01	OR 5515	9.30	7.75	4.42	12,223.00	6.67	1,822.00	1,822.00
10/26/01	OR 5519	10.68	12.47	3.39	11,143.00	5.33	1,697.10	1,697.10
10/27/01	OR 3618	12.42	12.68	3.70	10,776.00	6.00	173.80	173.80
10/27/01	OR 3863	9.41	6.22	4.20	12,578.00	6.26	543.20	543.20
10/27/01	OR 5210	9.28	6.74	4.23	12,462.00	6.33	654.70	654.70
10/27/01	OR 5430	9.14	7.32	4.50	12,426.00	6.71	1,885.90	1,885.90
10/27/01	OR 5548	11.12	9.78	4.36	11,554.00	6.81	1,713.20	1,713.20
10/27/01	OR 9040	9.17	6.79	4.15	12,546.00	6.17	1,611.40	1,611.40
+10/27/01	OT003B	12.78	6.07	3.78	11,958.00	5.94	1,928.00	1,928.00
10/27/01	T13635B	9.39	7.92	3.93	12,340.00	5.87	1,877.50	1,877.50
10/28/01	OR 1032	9.75	6.98	4.15	12,407.00	6.22	1,743.80	1,743.80
10/28/01	OR 1222	10.24	9.38	3.46	11,705.00	5.36	1,560.90	1,560.90
10/28/01	OR 4764	9.87	5.97	4.33	12,536.00	6.50	1,828.90	1,828.90
10/28/01	OR 5143	8.92	6.75	4.17	12,606.00	6.17	295.70	295.70
10/28/01	OR 5198	15.68	6.94	3.27	11,449.00	5.32	1,512.80	1,512.80
10/28/01	OR 5428	10.00	7.43	2.99	0.00	0.00	1,675.50	1,675.50
10/28/01	T13617B	9.38	6.34	4.31	12,526.00	6.45	1,954.20	1,954.20

Note: '+' Indicates that a Station Payment Quality Analysis was not found for one or more distributions.
Note: '*' Indicates that no Station Quality Analysis was found for one or more distributions.

Fuels Activity Management System
Coal Calculation Detail Report
Cincinnati Gas & Electric, W.H. Zimmer

10/23/2001 - 11/06/2001

<u>Date</u>	<u>Source</u>	<u>Ash Dry (%)</u>	<u>Moisture (%)</u>	<u>Sulfur Dry (%)</u>	<u>Heat Val Received (Btu/lb)</u>	<u>Unit 1 Sulfur (lb/MMBtu)</u>	<u>Bunker (Tons)</u>	<u>Distribution Total</u>
10/29/01	OR 3748	11.50	6.28	3.82	12,189.00	5.87	232.00	232.00
10/29/01	OR 3752	10.35	7.79	2.95	12,288.00	4.43	1,672.50	1,672.50
+10/29/01	OR 3755	14.92	6.58	3.03	11,365.00	4.98	1,485.70	1,485.70
10/29/01	OR 4924	10.17	7.22	3.13	12,490.00	4.65	1,718.80	1,718.80
10/29/01	OR 5060	9.46	6.32	4.05	12,595.00	6.02	1,593.70	1,593.70
+10/29/01	OR 5442	14.91	6.03	3.75	11,683.00	6.03	1,927.00	1,927.00
+10/29/01	OR 5502	6.60	5.50	2.46	13,445.00	3.46	310.70	310.70
10/29/01	OR 5512	12.59	6.75	4.23	11,984.00	6.58	1,858.30	1,858.30
10/29/01	T13509B	10.04	7.21	4.19	0.00	0.00	1,932.00	1,932.00
+10/30/01	OR 1176	12.99	5.57	3.74	12,065.00	5.85	83.87	83.87
10/30/01	OR 4875	12.15	7.36	4.55	11,911.00	7.08	1,375.10	1,375.10
10/30/01	OR 5117	11.87	9.38	3.74	11,465.00	5.91	492.80	492.80
10/30/01	OR 5207	13.76	11.05	3.57	11,228.00	5.66	1,264.20	1,264.20
10/30/01	OR 5263	11.08	7.58	4.03	12,061.00	6.18	1,769.90	1,769.90
10/30/01	OR 5312	10.48	8.42	3.94	12,048.00	5.99	1,869.40	1,869.40
10/30/01	OR 5375	12.06	7.88	4.23	11,887.00	6.56	1,794.80	1,794.80
10/30/01	OR 5498	11.63	9.96	3.74	11,361.00	5.93	1,549.00	1,549.00
10/30/01	OR 9006	9.47	8.16	4.04	12,300.00	6.03	1,177.40	1,177.40
10/31/01	OR 3772	8.77	7.21	3.97	12,534.00	5.88	1,625.70	1,625.70
10/31/01	OR 9006	9.47	8.16	4.04	12,300.00	6.03	677.80	677.80
11/01/01	High Sulfur Pile	10.32	8.42	3.39	11,985.00	5.18	8,776.80	8,776.80
+11/01/01	OR 5001	14.26	6.49	4.19	11,712.00	6.69	242.10	242.10
11/01/01	OR 5475	9.50	6.05	3.99	12,627.00	5.94	1,849.00	1,849.00
11/01/01	T13603B	9.94	7.34	4.14	12,309.00	6.23	1,758.30	1,758.30

Note: '+' Indicates that a Station Payment Quality Analysis was not found for one or more distributions.
Note: '*' Indicates that no Station Quality Analysis was found for one or more distributions.

Fuels Activity Management System
Coal Calculation Detail Report
Cincinnati Gas & Electric, W.H. Zimmer

10/23/2001 - 11/06/2001

<u>Date</u>	<u>Source</u>	Ash Dry (%)	Moisture (%)	Sulfur Dry (%)	Heat Val Received (Btu/lb)	Sulfur (lb/MMBtu)	Unit 1 Bunker (Tons)	Distribution Total
11/02/01	High Sulfur Pile	10.32	8.42	3.32	11,985.00	5.07	844.00	844.00
11/02/01	OR 5129	10.09	10.10	3.66	11,608.00	5.67	1,559.30	1,559.30
+11/02/01	OR 5388	14.37	8.38	1.49	11,388.00	2.40	1,872.90	1,872.90
11/02/01	OR 5487	9.98	7.01	4.17	12,427.00	6.24	1,834.70	1,834.70
+11/02/01	T13519B	14.54	6.38	3.29	11,739.00	5.25	2,014.33	2,014.33
+11/02/01	T13598B	17.44	6.60	1.13	11,495.00	1.84	1,910.57	1,910.57
+11/02/01	T13607B	17.06	8.36	1.17	11,111.00	1.93	2,029.63	2,029.63
+11/03/01	OR4755	19.90	5.99	1.44	11,059.00	2.45	1,692.10	1,692.10
+11/03/01	OR 4846	16.97	8.83	1.06	10,925.00	1.77	1,821.28	1,821.28
+11/03/01	OR4857	15.47	8.35	4.11	11,382.00	6.62	195.42	195.42
+11/03/01	OR 5165	13.88	7.59	3.91	11,654.00	6.20	62.92	62.92
+11/03/01	OR 5521	9.94	5.67	4.22	12,567.00	6.34	1,825.80	1,825.80
11/03/01	OR 7043	9.60	6.72	3.99	12,416.00	6.00	1,850.40	1,850.40
+11/04/01	OR 1019	14.78	8.11	3.89	11,447.00	6.25	1,541.77	1,541.77
+11/04/01	OR 1196	18.12	7.74	1.04	11,082.00	1.73	1,723.93	1,723.93
11/04/01	OR 4799	11.86	5.76	3.94	12,268.00	6.05	1,520.00	1,520.00
11/04/01	OR 5135	21.07	5.87	1.35	11,125.00	2.28	1,713.50	1,713.50
11/04/01	OR5359	11.38	6.21	4.11	12,463.00	6.19	1,867.00	1,867.00
11/04/01	OR5467	10.72	5.85	4.06	12,441.00	6.14	1,850.90	1,850.90
11/05/01	OR4799	11.86	5.76	3.94	12,268.00	6.05	70.30	70.30
11/05/01	OR4807	10.47	9.81	3.80	11,637.00	5.89	1,733.60	1,733.60
11/05/01	OR4819	11.06	5.96	4.10	12,332.00	6.25	1,863.00	1,863.00
11/05/01	OR4890	12.47	5.82	4.17	12,144.00	6.47	1,808.60	1,808.60
11/05/01	OR5137	13.78	5.62	3.67	11,929.00	5.81	1,666.00	1,666.00

Note: '+' Indicates that a Station Payment Quality Analysis was not found for one or more distributions.

Note: '*' Indicates that no Station Quality Analysis was found for one or more distributions.

11/19/2001

10: 47: 55 A M

Fuels Activity Management System
Coal Calculation Detail Report
Cincinnati Gas & Electric, W.H. Zimmer

10/23/2001 - 11/06/2001

<u>Date</u>	<u>Source</u>	<u>Dry (%)</u>	<u>Moisture (%)</u>	<u>Dry (%)</u>	<u>Received (Btu/lb)</u>	<u>Sulfur (lb/MMBtu)</u>	<u>Bunker (Tons)</u>	<u>Distribution Total</u>
11/05/01	OR 5410	11.85	8.87	4.25	11,549.00	6.71	286.80	286.80
11/05/01	OR 9042	14.71	8.55	4.73	11,195.00	7.73	1,625.40	1,625.40
11/05/01	T13600B	13.11	6.21	4.69	11,932.00	7.37	690.30	690.30
11/06/01	OR 4802	9.71	6.66	4.10	12,489.00	6.13	1,848.00	1,848.00
11/06/01	OR 4813	10.52	6.16	4.31	12,421.00	6.51	1,893.80	1,893.80
11/06/01	OR 4821	11.10	5.75	4.45	12,412.00	6.76	1,858.30	1,858.30
11/06/01	OR 5321	9.50	5.84	3.99	12,626.00	5.95	1,239.70	1,239.70
11/06/01	OR 6685	10.13	9.19	3.20	11,964.00	4.86	460.00	460.00
11/06/01	R 0204	10.05	6.09	4.17	12,489.00	6.27	1,821.30	1,821.30
11/06/01	T13575B	9.60	5.99	4.14	12,517.00	6.22	1,966.00	1,966.00

Note: '+' Indicates that a Station Payment Quality Analysis was not found for one or more distributions.
Note: '*' Indicates that no Station Quality Analysis was found for one or more distributions.

11/19/2001

10: 47: 55 A M

Appendix B – Plant Data Acquisition System Data

Below are several tables showing the average values for all of the operating data acquired during the project for each test.

Ontario Hydro	Plant Data														
	Plant CO ₂ In	Plant CO ₂ Out	Plant SO ₂	Plant SO ₂ In	Plant SO ₂ Out	Plant SO ₂ Removal Efficiency	Plant NO _x	Plant NO _x	Plant Flow	Plant Flow	Plant Flow	Plant Heat Rate	Plant Load	Plant Opacity	Plant Temp Stack
Test ID	%	%	lb/hr	ppm (wet)	ppm (wet)	%	lb/hr	ppm (dry)	kcfm	scfh	fps	mmBTU/hr	MW	%	°F
050801-1A1	9.96	12.01	0.300	1218	120	91.8	3.65	181	117	11925263	16.1	796	55.7	2.96	117
050901-1B	9.72	12.11	0.320	1387	130	92.5	4.26	197	116	12360567	16.6	832	59.3	3.03	116
050901-1C	9.48	11.91	0.363	1520	144	92.4	4.79	199	118	13059869	17.3	864	60.6	3.05	118
050901-1D	9.41	11.90	0.344	1438	137	92.5	4.57	195	119	12980441	17.3	858	59.5	3.50	119
051601-2A	9.30	11.70	0.440	1543	172	91.1	4.96	208	118	12817695	17.2	833	59.3	2.97	118
051601-2B	8.90	11.36	0.492	1605	187	90.9	5.39	187	118	12321562	16.9	778	55.0	2.73	118
051701-3A	9.34	11.81	0.497	1797	196	91.4	5.75	203	119	12414452	17.0	814	57.7	2.56	119
051701-3B	9.73	11.95	0.443	1700	177	91.5	5.22	196	121	12800454	17.4	850	58.2	2.75	121
051701-3C	10.02	12.09	0.405	1616	164	91.6	4.82	182	123	13237993	17.9	889	59.4	3.01	123
051801-4A	9.47	11.79	0.453	1647	179	91.3	5.20	189	120	12197413	16.7	800	56.6	2.80	120
051801-4B	9.45	11.78	0.479	1668	189	90.9	5.27	200	119	12363792	16.9	809	58.4	2.71	119
051801-4C	9.76	11.85	0.464	1710	184	91.1	5.24	181	120	11616800	16.1	764	55.9	2.66	120
061101-5A	9.25	11.91	0.994	2385	396	87.3	7.70	176	121	12074642	16.7	799	55.8	4.41	121
061101-5B	9.29	11.84	0.506	2047	200	92.3	6.59	181	123	12296832	16.9	809	53.1	3.20	123
061101-5C	9.34	11.93	0.587	1815	234	89.9	5.81	183	123	13055528	17.8	865	55.8	4.04	123
061201-6A	9.80	11.92	0.431	1793	172	92.1	5.46	179	120	12034334	16.6	797	56.1	3.06	120
061201-6B	10.02	12.00	0.386	1681	155	92.3	5.01	181	122	12373427	16.9	825	55.0	3.56	122
061301-7A	9.87	12.12	0.388	1449	157	91.2	4.39	177	122	11953799	16.6	805	53.9	3.83	122
061301-7B	9.70	11.92	0.493	1626	197	90.2	5.00	177	123	12584057	17.2	833	53.0	4.15	123
061301-7C	9.63	11.88	0.374	1553	149	92.3	4.82	181	124	12554602	17.2	829	53.0	4.89	124
061401-8A	9.80	12.03	0.385	1568	155	91.9	4.78	180	122	12026472	16.5	804	53.0	4.82	122
061401-8B	9.97	12.05	0.357	1448	144	91.8	4.34	181	122	12336097	16.9	825	53.0	5.54	122
061401-8C	10.01	12.08	0.406	1605	164	91.5	4.79	183	122	12349132	16.9	828	53.1	5.99	122
062501-9A	10.11	13.01	0.468	1983	204	92.0	5.86	198	122	12792874	17.2	924	56.7	3.23	122
062601-10A	9.82	12.70	0.609	2052	259	90.3	6.26	187	121	12585846	17.0	887	55.9	3.15	121
062701-11A	12.58	11.35	0.308	1917	134	94.9	4.56	193	122	13196197	17.5	818	55.1	3.01	122
062801-12A	11.91	10.91	0.564	1827	191	87.5	4.59	432	121	12330311	16.8	721	56.9	3.07	121
062901-13A	11.82	10.38	0.420	1916	146	91.3	4.84	186	122	12897961	17.4	744	54.9	3.23	122
063001-14A	11.71	10.05	0.368	1683	124	91.4	4.30	160	124	12565964	17.2	702	54.8	3.28	124
070101-15A	10.43	8.95	0.315	1634	95	93.3	4.68	139	117	9535192	13.9	474	37.7	3.11	117
070201-16A	11.33	10.39	0.337	1904	117	93.3	5.02	147	112	9594815	13.8	556	44.0	3.10	112

Table B1 – Endicott Operating Data

Plant Data															
Ontario Hydro	Plant CO ₂ In	Plant CO ₂ Out	Plant SO ₂	Plant SO ₂ In	Plant SO ₂ Out	Plant SO ₂ Removal Efficiency	Plant NO _x	Plant NO _x	Plant Flow	Plant Flow	Plant Flow	Plant Heat Rate	Plant Load	Plant Opacity	Plant Temp Stack
Test ID	%	%	lb/hr	ppm (wet)	ppm (wet)	%	lb/hr	ppm (dry)	kcfm	scfh	fps	mmBTU/hr	MW	%	°F
070601-17A	12.44	9.84	0.303	1711	100	92.6	4.11	136	118	9102964	13.5	498	46.9	3.13	118
070701-18A	11.26	8.88	0.256	1489	76	93.5	3.95	171	117	8404419	12.8	415	36.8	3.29	117
070801-19A	11.63	9.39	0.269	1552	84	93.3	3.99	194	122	9155271	13.8	478	43.8	3.18	122
070901-20A	12.12	11.75	0.351	1945	138	92.7	4.80	183	122	10865267	15.4	709	57.2	3.02	122
071001-21A	11.76	10.53	0.291	1690	102	93.2	4.30	198	122	10926233	15.5	639	55.8	2.97	122
071101-22A	10.43	10.75	0.349	1820	126	93.3	5.22	191	118	11154079	15.5	667	57.8	3.45	118
071201-23A	12.17	11.16	0.374	1935	140	92.1	4.75	160	118	11480691	15.8	711	57.1	2.74	118
071201-23B	12.38	11.40	0.386	1980	147	91.9	4.78	164	119	10811263	15.2	684	57.2	2.67	119
071201-23C	12.22	11.80	0.351	1839	139	92.2	4.50	171	120	10592030	15.0	694	56.2	2.87	120
072401-24A	12.44	9.53	0.393	2033	125	92.0	4.88	180	124	11032786	15.7	584	56.6	3.11	124
072401-24B	12.66	9.37	0.479	2175	150	90.7	5.13	184	125	11172364	15.9	582	56.3	3.21	125
072401-24C	12.45	9.12	0.786	2272	240	85.6	5.45	177	126	11172695	15.9	566	54.7	3.12	126
080701-25A	12.02	10.77	0.362	1745	130	91.6	4.34	169	122	9478722	14.0	567	48.4	3.23	122
080701-25B	12.06	10.39	0.488	2095	170	90.6	5.19	168	124	9315407	13.9	537	46.3	3.24	124
080701-25C	11.97	10.19	0.660	2311	225	88.6	5.77	159	125	9603581	14.3	543	45.1	3.30	125
082101-26A	12.34	10.59	0.367	1801	130	91.6	4.36	136	119	10797994	15.2	636	53.9	3.86	119
082101-26B	12.29	10.53	0.437	1984	154	90.9	4.83	147	120	10395665	14.8	608	55.6	3.54	120
082101-26C	12.48	10.66	0.399	1857	143	91.0	4.45	147	120	10805861	15.2	640	57.7	3.66	120
090501-27A	12.37	10.76	0.415	1924	149	91.1	4.65	162	119	11088446	15.4	663	55.9	14.66	119
090501-27B	12.23	10.76	0.407	1911	146	91.3	4.67	170	120	10608506	15.0	634	55.6	8.03	120
090501-27C	12.32	10.53	0.397	1845	140	91.1	4.47	177	120	11302041	15.6	661	57.1	10.23	120
091801-28A	12.21	10.59	0.433	1949	153	90.9	4.77	154	119	11174951	15.6	657	57.0	2.59	119
091801-28B	12.23	10.64	0.447	1982	159	90.8	4.84	171	119	11126660	15.6	658	56.9	3.13	119
091801-28C	12.47	10.74	0.454	2046	163	90.7	4.90	165	120	11294249	15.8	674	57.1	3.30	120
100201-29A	12.77	11.89	0.559	2157	233	88.4	5.05	194	121	11908949	16.4	788	59.3	3.28	121
100201-29B	12.66	10.91	0.653	2091	238	86.8	4.94	172	121	11529287	16.0	699	59.2	3.34	121
100201-29C	12.83	10.94	0.519	1975	190	88.7	4.60	168	122	11414970	15.9	694	58.9	5.57	122
100301-30A	12.54	10.94	0.584	2271	214	89.2	5.42	146	119	12480417	16.9	759	55.6	4.39	119
100301-30B	12.49	10.97	1.048	2374	385	81.6	5.68	164	121	11996112	16.6	731	58.9	4.54	121
100301-30C	12.67	11.12	1.349	2336	502	75.6	5.51	159	120	11578690	16.1	715	59.0	4.73	120

Table B2 – Endicott Operating Data

	Scrubber Data								Reagent Flow	Water Flow	Ambient Data				
	Slurry Concentration	Limestone feed rate	Absorber pH	WFGD Temp In	WFGD Temp Out	Slurry Pump Amp1	Slurry Pump Amp2	Slurry Pump Amp3			MTI Oxygen Analyzer	Pbar	Temp Dry Bulb	Temp Wet Bulb	Humidity Ambient
Test ID	%	gpm		°F	°F	A	A	A	%	gph	gph	in Hg	°F	°F	moles/mole dry air
050801-1A1	10.29	15.6	6.36	359		33.5	0.0	31.3	6.20			30.1	68.3	53.7	0.0087
050901-1B	9.25	28.1	6.29	354		33.4	0.0	31.2	6.27			30.2	59.9	51.6	0.0100
050901-1C	9.90	30.0	6.29	361		33.5	0.0	31.2	6.35			30.1	66.3	54.6	0.0103
050901-1D	10.56	31.2	6.29	368		33.5	0.0	31.3	6.23			30.1	66.7	55.7	0.0111
051601-2A	12.31	24.2	6.43	358	128	33.5	33.7	0.0	6.48	2.93	21.61	28.4	62.5	59.9	0.0177
051601-2B	12.38	26.7	6.45	350	127	33.5	33.7	0.0	6.96	2.90	21.42	28.4	66.5	62.8	0.0194
051701-3A	12.37	22.0	6.47	352	128	33.5	33.7	0.0	6.34	0.29	21.04	28.5	64.8	62.6	0.0197
051701-3B	12.83	20.3	6.48	361	130	33.5	33.7	0.0	5.96	0.30	20.92	28.5	71.0	65.5	0.0208
051701-3C	13.50	18.3	6.48	371	131	33.6	33.8	0.0	5.66	0.30	20.70	28.5	76.9	65.0	0.0181
051801-4A	14.01	18.0	6.48	352	127	33.5	0.0	31.6		0.07	20.09	28.6	66.3	61.4	0.0178
051801-4B	13.45	24.0	6.48	357	127	33.4	0.0	31.5		0.06	19.91	28.6	62.2	58.2	0.0160
051801-4C	13.49	21.5	6.49	357	128	33.5	0.0	31.6		0.06	19.99	28.6	65.5	59.5	0.0161
061101-5A	14.17	44.5	5.91	351	129	31.5	26.1	29.9	6.47		18.70	28.5	71.8	71.0	0.0274
061101-5B	13.93	16.7	5.91	358	130	30.8	32.0	29.4	6.66		18.58	28.5	77.7	76.2	0.0325
061101-5C	13.70	23.2	5.92	367	131	30.9	32.0	29.5	6.65		18.71	28.5	78.5	76.8	0.0331
061201-6A	12.84	25.4	5.94	352	128	33.4	0.0	31.4	6.43	0.17	18.61	28.5	71.2	70.4	0.0268
061201-6B	13.09	18.9	5.95	362	130	33.4	0.0	31.4	6.45	0.17	18.49	28.5	77.8	76.6	0.0331
061301-7A	13.42	17.0	5.99	355	129	33.3	0.0	31.5	6.68	0.29	18.07	28.6	73.6	73.0	0.0294
061301-7B	13.81	21.8	6.00	361	131	32.7	33.5	2.6	6.70	0.26	12.28	28.6	79.9	78.9	0.0357
061301-7C	13.66	22.5	6.00	371	131	33.2	0.0	31.5	6.75	0.30	0.00	28.5	81.5	80.4	0.0377
061401-8A	13.22	18.8	6.02	352	129	33.3	33.9	0.0	6.90	1.01	19.46	28.6	75.8	75.1	0.0315
061401-8B	13.37	18.5	6.03	362	130	33.3	33.9	0.0	6.66	1.04	19.18	28.6	82.9	81.7	0.0392
061401-8C	13.59	21.6	6.03	364	130	33.4	33.9	0.0	6.51	1.02	18.84	28.6	84.2	83.0	0.0410
062501-9A	13.65	18.6	6.41	375	131	30.6	31.9	29.2	7.06	1.03	13.16	28.9	81.3	81.3	0.0388
062601-10A	13.27	28.7	6.47	364	129	30.6	31.9	29.1	6.69	1.01	0.00	28.9	77.9	77.8	0.0344
062701-11A	14.77	42.3	6.48	365	129	30.8	32.1	29.4		0.99	0.00	29.0	76.9	76.9	0.0333
062801-12A	16.07	47.3	6.38	360	130	33.6	0.0	31.9		1.00	0.00	28.9	73.8	66.0	0.0200
062901-13A	15.60	25.9	6.33	361	129	30.7	32.3	29.4		1.00	0.00	28.8	77.3	67.0	0.0200
063001-14A	14.73	19.9	6.29	366	130	30.6	32.1	29.2		1.00	0.00	28.6	77.4	69.4	0.0230
070101-15A	15.36	16.5	6.45	332	125	0.0	34.3	31.8		1.00	0.00	28.6	69.0	63.6	0.0192
070201-16A	15.01	20.0	6.56	322	123	0.0	34.4	32.0		1.00	0.01	29.0	55.9	48.2	0.0091

Table B3 – Endicott Operating Data

	Scrubber Data									Reagent Flow	Water Flow	Ambient Data			
	Ontario Hydro	Slurry Concentration	Limestone feed rate	Absorber pH	WFGD Temp In	WFGD Temp Out	Slurry Pump Amp1	Slurry Pump Amp2	Slurry Pump Amp3	MTI Oxygen Analyzer		Pbar	Temp Dry Bulb	Temp Wet Bulb	Humidity Ambient
Test ID	%	gpm		°F	°F	A	A	A	%	gph	gph	in Hg	°F	°F	moles/mole dry air
070601-17A	15.66	15.2	6.74	340	126	30.8	32.1	29.7		1.00	0.00	28.7	75.2	58.8	0.0119
070701-18A	15.85	15.1	6.78	322	124	33.3	0.0	31.9	8.24	1.00	0.00	28.6	66.2	62.2	0.0187
070801-19A	15.17	20.0	6.80	359	128	33.2	0.0	31.8	7.70	1.00	0.00	28.6	76.5	68.4	0.0222
070901-20A	15.83	30.6	6.82	364	130	31.6	21.8	30.5	6.18	1.00	0.00	28.6	76.6	67.9	0.0215
071001-21A	13.80	22.4	6.85	365	129	30.5	32.0	29.4		1.00	0.00	28.5	78.4	67.4	0.0204
071101-22A	13.85	33.7	6.89	355	127	30.5	32.1	29.6	6.55	1.00	0.00	28.6	69.3	59.0	0.0142
071201-23A	13.43	24.9	6.91	349	127	30.5	32.0	29.5	6.84	1.00	0.00	28.7	65.8	57.9	0.0143
071201-23B	13.60	26.0	6.91	356	128	30.5	32.0	29.5	6.62	1.00	0.00	28.7	73.6	61.7	0.0155
071201-23C	13.64	21.8	6.91	362	128	30.5	32.1	29.6	6.79	1.00	0.00	28.7	75.4	62.6	0.0158
072401-24A	15.79	32.8	6.79	366	131	30.6	32.2	29.8	6.87	1.00	0.00	28.6	73.5	71.5	0.0273
072401-24B	16.12	45.8	6.78	371	132	30.6	32.3	29.8	6.79	1.00	0.00	28.6	79.3	73.4	0.0277
072401-24C	16.73	44.9	6.77	376	132	30.8	32.4	29.8	7.04	1.00	-0.01	28.5	81.0	72.7	0.0263
080701-25A	14.30	15.3	7.27	347	129	32.8	0.00	31.6	6.80	1.00	0.00	28.8	77.2	70.3	0.0242
080701-25B	14.52	38.4	7.25	354	130	32.9	0.00	31.7	6.92	1.00	-0.01	28.8	82.2	73.9	0.0272
080701-25C	15.03	45.0	7.24	360	131	33.0	0.00	31.8	6.72	1.00	0.00	28.7	84.4	75.3	0.0285
082101-26A	15.07	19.1	5.24	343	127	30.1	31.7	30.2	6.51	0.99	0.00	28.8	65.8	59.4	0.0158
082101-26B	14.98	28.0	5.16	354	128	30.0	31.7	30.1	6.29	0.99	0.00	28.8	73.6	61.6	0.0153
082101-26C	14.77	24.8	5.33	366	129	30.0	31.6	30.2	6.07	0.99	0.00	28.7	76.2	62.1	0.0149
090501-27A	16.79	26.7	4.93	346	127	30.5	32.0	30.6	6.67	1.00	0.00	28.9	63.8	58.9	0.0160
090501-27B	18.83	22.3	4.66	355	128	30.7	32.3	30.9	6.49	1.00	0.00	28.9	70.8	63.1	0.0179
090501-27C	17.86	25.8	4.66	365	128	30.7	32.2	30.8	6.67	1.00	0.00	28.8	71.7	64.7	0.0193
091801-28A	10.46	29.5	3.60	358	128	29.7	31.2	30.2	6.33	1.00	0.00	28.7	66.5	59.9	0.0161
091801-28B	10.81	30.4	3.68	367	129	29.9	31.3	30.2	6.25	1.00	0.00	28.6	70.3	60.4	0.0153
091801-28C	10.89	34.1	3.71	373	129	29.8	31.3	30.3	6.08	1.00	0.00	28.6	68.8	60.0	0.0154
100201-29A	14.70	43.0	4.32	366	129	30.1	31.7	31.0	5.72	1.00	0.00	28.6	64.1	58.1	0.0152
100201-29B	15.14	43.1	4.31	373	129	30.2	31.7	31.0	5.69	1.00	0.00	28.6	72.1	59.1	0.0133
100201-29C	15.66	43.3	4.27	377	130	30.4	31.8	31.2	5.63	1.00	0.00	28.6	74.0	59.2	0.0128
100301-30A	15.53	32.8	4.28	348	127	30.3	31.8	31.1	5.98	0.00	0.00	28.6	64.4	55.7	0.0128
100301-30B	16.40	42.6	4.28	368	128	30.3	31.9	31.3	5.82	0.00	0.00	28.5	73.4	60.7	0.0145
100301-30C	17.00	42.9	4.20	374	128	30.6	32.0	31.4	5.73	0.00	0.00	28.5	76.8	65.8	0.0191

Table B4 – Endicott Operating Data

		MTI					Boiler, Stack and Misc.											
O-H Test ID	Date/Time of O-H Test Start	Reagent Flow gph	Dry Bulb Temp °F	Wet Bulb Temp °F	Hg CEM O2 %	Coal Flow klb/hr	Coal+Oil Flow klb/hr	Net Load MW	Aux Load MW	Inlet Pres psia	Stack Pres psia	Stack Temp °F	Stack Flow 1 kcfm	Stack Flow 2 kcfm	Soot Blwr Steam klb/hr	Ambient Temp °F	Pbar "Hg	ME Water Flow gpm
31A	10/23/2001 10:15	27.0	62.9	57.4		1023	1023	1302	93	27.4	28.9	NA	2447	3234	28	76	28.76	758
31B	10/23/2001 13:45	27.0	64.5	58.8	6.07	1032	1032	1305	93	27.4	28.9	NA	2437	3226	23	76	28.74	750
32A	10/24/2001 10:17	27.2	56.5	55.0	5.85	1026	1026	1304	94	27.3	28.9	NA	2550	3277	8	69	28.72	739
33A	10/25/2001 11:00	27.3	42.8	38.6	5.88	1039	1039	1307	95	27.6	29.1	NA	2419	3241	19	54	28.96	739
34A	10/26/2001 11:00	27.3	31.4	29.1	5.97	984	984	1304	96	27.8	29.3	NA	2699	3703	36	43	29.17	732
35A	10/27/2001 9:26	27.4	28.2	26.8	6.09	1018	1019	1303	97	28.0	29.5	NA	2542	4252	29	42	29.38	719
36A	10/28/2001 8:32	27.2	29.9	28.7	6.68	885	885	1131	94	28.4	29.7	NA	2546	4168	10	44	29.60	722
37A	10/29/2001 9:30	27.2	38.8	35.5	6.18	1020	1020	1299	97	28.1	29.7	NA	2668	3200	24	53	29.57	661
38A	10/30/2001 9:30	27.3	40.0	37.2	6.08	1016	1016	1302	97	28.0	29.7	NA	2621	3180	21	54	29.52	601
39A	11/1/2001 8:00	27.2	50.5	45.7	6.34	1014	1014	1304	96	27.9	29.4	NA	2768	3198	8	63	29.22	638
40A	11/2/2001 8:00	27.2	59.3	54.8	6.25	1007	1010	1301	95	27.7	29.3	NA	2739	3211	25	70	29.17	635
41A	11/3/2001 8:45	27.2	39.5	38.2	8.69	699	700	819	78	28.7	29.6	NA	2660	2509	8	54	29.44	686
42A	11/4/2001 8:00	27.2	33.9	33.5	8.49	674	674	821	79	28.6	29.5	NA	2876	2521	8	47	29.35	722
43A	11/5/2001 8:22	27.2	34.1	32.7	6.32	986	986	1305	94	28.0	29.5	NA	2014	3249	14	46	29.34	1136
44A	11/6/2001 8:00	40.7	24.7	24.8	6.08	999	999	1302	97	28.0	29.5	NA	2040	3201	27	39	29.33	687

		Zimmer Gas Analyzers												ESP Data					
O-H Test ID	Date/Time of O-H Test Start	AH 1 Inlet O ₂ %	AH 2 Inlet O ₂ %	AH 3 Inlet O ₂ %	Inlet SO ₂ ppm	Stack SO ₂ ppm	Inlet SO ₂ lb/mBtu	Stack SO ₂ lb/mBtu	SO ₂ Removal %	Inlet CO ₂ %	Stack CO ₂ %	Stack NOx lb/mBtu	Stack NOx ppm	ESP 1&2 Opacity %	ESP 1 Opacity %	ESP 2 Opacity %	ESP 1 Temp Out °F	ESP 2 Temp Out °F	
31A	10/23/2001 10:15	4.4	3.7	2.8	2536	430	5.86	1.17	80.0	13.0	11.1	0.49	254	2	1	2	350	342	
31B	10/23/2001 13:45	4.2	3.7	2.8	2465	184	5.72	0.51	91.0	12.9	11.1	0.49	255	1	1	1	354	344	
32A	10/24/2001 10:17	4.3	3.7	2.9	2457	193	5.75	0.53	90.9	12.8	10.9	0.49	254	5	1	5	351	340	
33A	10/25/2001 11:00	4.5	4.2	2.9	2857	237	6.72	0.64	90.4	12.7	10.9	0.48	249	7	0	14	345	337	
34A	10/26/2001 11:00	4.3	4.5	2.6	2748	197	6.34	0.53	91.7	12.9	11.0	0.48	248	1	1	1	348	339	
35A	10/27/2001 9:26	4.8	4.4	3.8	2335	162	5.56	0.44	92.0	12.5	10.8	0.53	272	1	1	1	347	334	
36A	10/28/2001 8:32	4.4	4.7	4.0	2370	174	5.92	0.49	91.7	12.0	10.4	0.48	235	1	1	1	335	322	
37A	10/29/2001 9:30	3.7	4.4	3.9	1957	132	4.74	0.36	92.4	12.4	10.8	0.54	274	1	1	1	347	334	
38A	10/30/2001 9:30	4.4	4.4	3.1	2521	171	5.84	0.46	92.2	12.9	11.1	0.50	261	1	1	2	353	341	
39A	11/1/2001 8:00	4.1	4.4	3.8	2582	153	6.15	0.42	93.1	12.5	10.8	0.53	270	1	1	1	345	331	
40A	11/2/2001 8:00	3.8	3.9	4.0	2233	166	5.36	0.46	91.5	12.4	10.8	0.56	284	2	1	3	353	337	
41A	11/3/2001 8:45	5.9	7.2	5.9	868	84	2.40	0.26	89.4	10.9	9.5	0.48	214	1	1	1	346	334	
42A	11/4/2001 8:00	5.8	6.7	5.7	1580	109	4.36	0.34	92.2	10.8	9.4	0.45	200	1	1	2	340	328	
43A	11/5/2001 8:22	4.0	4.5	2.4	2581	200	6.00	0.55	90.7	12.8	11.0	0.48	247	1	1	1	350	338	
44A	11/6/2001 8:00	4.0	5.0	2.4	2577	207	6.03	0.57	90.6	12.7	10.8	0.45	228	1	1	1	345	333	

Table B5 – Zimmer Operating Data

O-H Test ID	Date/Time of O-H Test Start	WFGD Tray pH												WFGD Slurry % Solids					
		Mod 1 Probe 1 pH	Mod 1 Probe 2 pH	Mod 2 Probe 1 pH	Mod 2 Probe 2 pH	Mod 3 Probe 1 pH	Mod 3 Probe 2 pH	Mod 4 Probe 1 pH	Mod 4 Probe 2 pH	Mod 5 Probe 1 pH	Mod 5 Probe 2 pH	Mod 6 Probe 1 pH	Mod 6 Probe 2 pH	Mod 1 % Sol	Mod 2 % Sol	Mod 3 % Sol	Mod 4 % Sol	Mod 5 % Sol	Mod 6 % Sol
31A	10/23/2001 10:15	6.3	6.4	6.2	6.2	6.2	6.6	6.2	6.2	6.2	6.2	5.6	21	22	23	21	23		
31B	10/23/2001 13:45			6.5	6.6	6.5	6.5	6.8	6.5	6.5	6.5	6.9	6.4		22	23	21	23	25
32A	10/24/2001 10:17			6.3	6.2	6.2	6.3	6.6	6.2	6.3	6.3	6.3	5.7		22	23	21	23	
33A	10/25/2001 11:00			6.4	6.4	6.4	6.3	6.7	6.4	6.4	6.4	6.3	5.7		22	23	21	23	27
34A	10/26/2001 11:00			6.2	6.3	6.2	6.3	6.5	6.3	6.3	6.2	6.2	5.9		23	23	20	24	
35A	10/27/2001 9:26			6.2	6.2	6.2	6.2	6.4	6.2	6.2	6.2	6.2	24	21	24	20	24		
36A	10/28/2001 8:32			6.0	6.1	6.1	6.0	6.3	6.1	6.1	6.0	6.1	24	22	23	22	23		
37A	10/29/2001 9:30			6.1	6.2	6.4	6.4	6.5	6.2	6.2	6.2	6.2	22	23	22	23	22	23	22
38A	10/30/2001 9:30			6.3	6.3	6.5	6.5	6.4	6.3	6.3	6.2	6.2	22	23	22	23	23	23	
39A	11/1/2001 8:00	6.4	6.5	6.4	6.5	6.6	6.2	6.4	6.3			6.5	6.6	22	22	22	21		18
40A	11/2/2001 8:00	5.9	6.0	5.9	6.0	5.9	6.0	6.0	6.0			6.0	6.1	25	23	22	22		22
41A	11/3/2001 8:45	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.0			6.1	6.0	25	24	22	22		17
42A	11/4/2001 8:00	6.4	6.5	6.5	6.5	6.5	6.5	6.7	6.7			6.7	6.7	25	23	22	20		23
43A	11/5/2001 8:22	6.4	6.5	6.3	6.3	6.6	6.5	6.2	6.2			6.5	6.5	16	23	22	19		30
44A	11/6/2001 8:00	6.3	6.3	6.3	6.3	6.4	6.3	6.3	6.3			6.3	6.3	28	21	21	19		22

O-H Test ID	Date/Time of O-H Test Start	WFGD ID Fan Amps						WFGD Inlet/Outlet Temperature											
		Mod 1 Amps	Mod 2 Amps	Mod 3 Amps	Mod 4 Amps	Mod 5 Amps	Mod 6 Amps	Mod 1 Inlet °F	Mod 1 Outlet °F	Mod 2 Inlet °F	Mod 2 Outlet °F	Mod 3 Inlet °F	Mod 3 Outlet °F	Mod 4 Inlet °F	Mod 4 Outlet °F	Mod 5 Inlet °F	Mod 5 Outlet °F	Mod 6 Inlet °F	Mod 6 Outlet °F
31A	10/23/2001 10:15		285	287	294	286	289	123	123	349	131	359	132	359	126	355	128	344	NA
31B	10/23/2001 13:45		285	285	292	286	289	91	106	349	130	360	133	361	127	357	129	354	NA
32A	10/24/2001 10:17		287	295	291	286	290	74	70	330	127	359	132	359	127	355	129	345	NA
33A	10/25/2001 11:00		279	294	290	283	287	59	59	342	126	352	130	353	124	350	126	333	NA
34A	10/26/2001 11:00		282	294	290	285	291	46	51	342	125	353	128	354	124	350	125	328	NA
35A	10/27/2001 9:26		284	296	292	289	294	45	55	342	125	353	129	350	123	347	125	328	NA
36A	10/28/2001 8:32		267	280	279	273	278	42	58	333	125	343	130	341	123	337	125	317	NA
37A	10/29/2001 9:30		286	296	297	291	296	50	67	346	127	356	131	353	125	349	126	338	NA
38A	10/30/2001 9:30		285	295	296	289	295	55	68	350	129	360	131	359	126	355	127	347	NA
39A	11/1/2001 8:00	288	285	294	286		288	349	129	355	128	353	130	349	124	72	85	333	NA
40A	11/2/2001 8:00	293	290	299	289		291	355	131	361	131	360	131	355	126	72	69	340	NA
41A	11/3/2001 8:45	252	247	252	248		251	349	126	355	125	351	127	354	121	60	58	325	NA
42A	11/4/2001 8:00	251	247	252	246		249	346	125	351	124	348	127	350	121	54	54	319	NA
43A	11/5/2001 8:22	287	279	292	281		282	356	129	361	127	358	128	353	125	56	55	328	NA
44A	11/6/2001 8:00	289	283	295	283		285	349	131	355	128	352	129	344	123	52	54	322	NA

Table B6 – Zimmer Operating Data

O-H Test ID	Date/Time of O-H Test Start	WFGD Slurry Recirculation Pump Amps												WFGD Differential Pressure					
		Mod 1 Pump 1 Amps	Mod 1 Pump 2 Amps	Mod 2 Pump 1 Amps	Mod 2 Pump 2 Amps	Mod 3 Pump 1 Amps	Mod 3 Pump 2 Amps	Mod 4 Pump 1 Amps	Mod 4 Pump 2 Amps	Mod 5 Pump 1 Amps	Mod 5 Pump 2 Amps	Mod 6 Pump 1 Amps	Mod 6 Pump 2 Amps	"H ₂ O	"H ₂ O	"H ₂ O	"H ₂ O	"H ₂ O	"H ₂ O
31A	10/23/2001 10:15		36		39	37		34			37		36	0.9	2.5	2.5	2.1	2.0	1.7
31B	10/23/2001 13:45				39	36		33			37		37	0.9	2.5	2.5	2.0	2.1	1.8
32A	10/24/2001 10:17				39	37		34			37		37		25	27	1.7	2.0	1.7
33A	10/25/2001 11:00				40	37		34			38		36		24	2.7	1.6	2.0	1.7
34A	10/26/2001 11:00				39	37		34			38		37		24	2.6	1.8	2.1	1.7
35A	10/27/2001 9:26				39	37		34			37		37		24	2.7	1.8	2.1	1.7
36A	10/28/2001 8:32				39	37		34			38		38		21	2.4	1.8	1.8	1.5
37A	10/29/2001 9:30				40	37		34			37		38		25	2.6	1.7	2.1	1.7
38A	10/30/2001 9:30				39	37		34			37		38		25	2.6	1.7	2.1	1.7
39A	11/1/2001 8:00	29	32		39	32	38	34			29	33	26	25	3.0	1.7			1.8
40A	11/2/2001 8:00	29	33		40	35	37	34			35		31	26	3.0	1.7			1.6
41A	11/3/2001 8:45		36		40	37		34			33		1.7	1.9	1.9	1.2			1.2
42A	11/4/2001 8:00	27	32		39	37		33			34		1.5	1.8	1.9	1.3			1.2
43A	11/5/2001 8:22	32			38	37		34			34		22	25	2.8	2.2			1.6
44A	11/6/2001 8:00	33		32	35	37		32	34			29	34	27	28	28	21		1.8

Table B7 – Zimmer Operating Data