

Enhancing Carbon Reactivity for Mercury Control: Field Test Results from Leland Olds

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ABSTRACT

Currently, carbon injection technologies have been shown to be the most viable commercial options for utility systems without SO₂ scrubbers, including those emitting high levels of elemental mercury (Hg⁰). Lignites, because of their low chlorine and high calcium contents, produce high levels of Hg⁰ and have also shown low Hg–sorbent reactivity. Two technologies have been identified that overcome these problems by using either 1) sorbent enhancement additives or 2) treated carbons to significantly increase sorbent reactivity and resultant capture of Hg. Both technologies have been successfully demonstrated in pilot-scale and short-term field tests and are currently being tested and verified at the utility scale. The first of these tests has just been completed as part of the U.S. Department of Energy’s National Energy Technology Laboratory mercury control field test program at the Leland Olds Station located in North Dakota. Test objectives and preliminary results will be discussed and presented.

INTRODUCTION

Leland Olds Station Unit 1 was the first of four units to be tested as part of the project entitled “Enhancing Carbon Reactivity in Mercury Control in Lignite-Fired Systems.” The goal of the larger project is to evaluate the effectiveness of carbon injection on mercury speciation and capture for units equipped with either an electrostatic precipitator (ESP) only or a spray dryer–fabric filter combination. To accomplish the goal, testing was conducted at Leland Olds Station Unit 1 to evaluate the effectiveness of carbon injection with a sorbent enhancement additive (SEA) on mercury speciation and capture for the unit while firing 100% lignite. Parametric testing was performed to optimize carbon and enhancement additive rates to achieve a target mercury removal of 55% (or greater) while minimizing additive quantity and costs.

EXPERIMENTAL

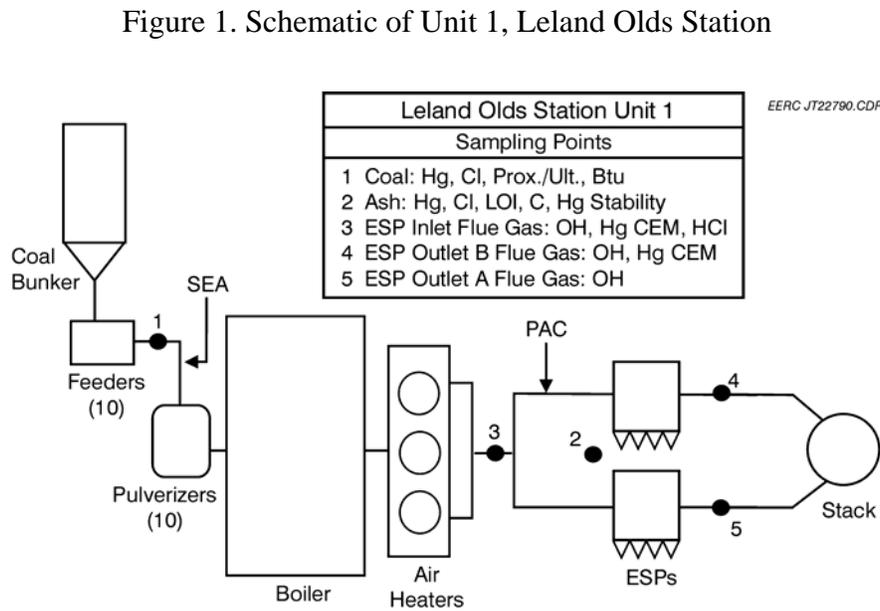
The goal of the testing at Leland Olds Station Unit 1 was to evaluate enhanced carbon injection for mercury control. The project tested the application of both powdered activated carbon (PAC) injection and a sorbent enhancement additive for a 1-month period on Unit 1 at Leland Olds Station in Stanton, North Dakota.

Test Unit Information

Leland Olds Station is located 1 mile south and 3.5 miles east of Stanton, North Dakota. Unit 1 has been operational since 1966. Specific unit information is outlined as follows:

Boiler:	220 MW Pulverized coal wall-fired 10 feeders, 10 pulverizers 20 low-NO _x burners with overfire air
Fuel:	Lignite coal from the Freedom mine Occasional blending with 30% Powder River Basin coal from the Dry Fork mine (Wyoming)
Air Pollution Control Devices:	Two parallel ESPs, specific collection area (SCA) 320 ft ² /1000 cfm Four rows of hoppers Eight hoppers per row

A schematic of the unit is shown in Figure 1. The figure shows the locations for sampling as well as the SEA and PAC injection locations.



Test Matrix

As part of the project, baseline measurements for mercury speciation and removal were taken for comparison to data gathered during a monthlong test of the mercury control technologies.

Following the baseline testing, parametric tests were performed in order to determine the PAC and SEA injection rates necessary to achieve the target 55% removal.

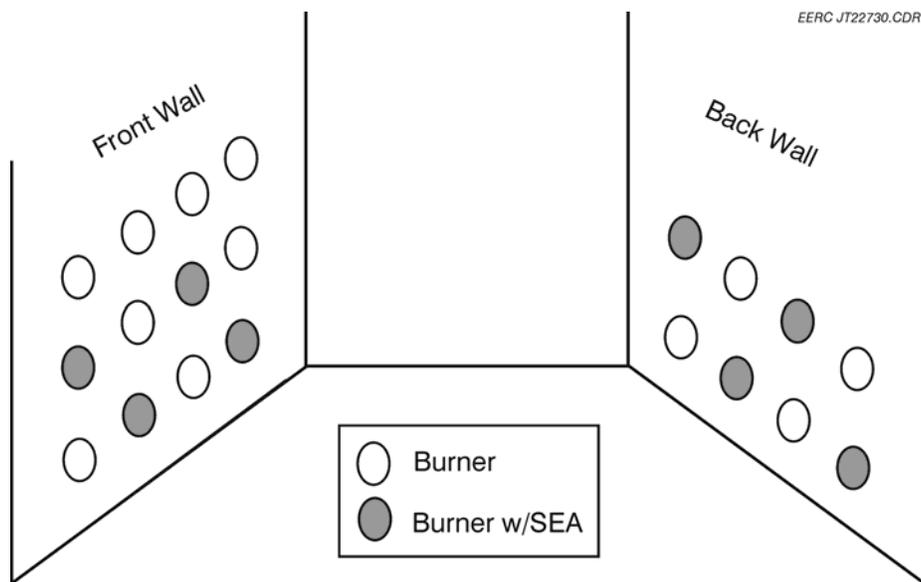
The parametric testing generated data for three SEA and three PAC rates to bracket the targeted mercury removal of 55%. These data were used to determine the optimum SEA and PAC rates for 55% mercury removal. The monthlong test was run with an SEA rate equivalent to 500 ppm chlorine in the coal and a PAC rate of 3 lb/macf.

Systems Operation and Monitoring

The SEA was injected into the coal stream between the feeders and the pulverizers. Four of the ten pulverizers were used for SEA addition. This was done in an attempt to distribute the additive throughout the boiler. These four pulverizers supplied the SEA along with the coal to eight of the 20 burners: two on the front wall lower level, two on the back wall lower level, two on the front wall middle level, and two on the back wall middle level. Figure 2 shows a schematic of the burner configuration and the SEA injection matrix. The SEA control panel received a signal from the plant allowing the SEA injection rate to be set and controlled proportionally to the overall coal feed rate.

The PAC was injected into the duct on Side B of the unit, upstream of the ESP and downstream of the ESP inlet sampling location. Six ports were used to inject the carbon into the duct using a 6×2 grid. The control panel for the PAC system was configured to allow the PAC addition to be set and controlled proportionally to the unit load in megawatts.

Figure 2. Burner Schematic and SEA Injection



Flue Gas Sampling

The Energy & Environmental Research Center (EERC) set up two Hg continuous emission monitors (CEMs), one at the ESP inlet (upstream of the PAC injection location) and the other at the ESP outlet of Side B. In addition, an HCl analyzer was set up at the ESP inlet location. The HCl analyzer was used to monitor HCl in the flue gas and was correlated with the SEA injection rate to indirectly monitor the SEA injection rate. The Hg CEMs were used primarily to monitor total gas-phase mercury and occasionally Hg⁰, as determined by the project team.

The EERC also used the Ontario Hydro (OH) method to monitor flue gas mercury concentrations. The test matrix for OH method sampling included triplicate samples at the inlet and outlet locations; once for the baseline and three times during the monthlong test.

Coal and Ash Sampling and Analysis

Coal samples were collected from the feeders and combined into a daily composite for each of the OH testing days. The coal samples were analyzed for Hg, Cl, proximate, ultimate, and Btu analyses.

RESULTS AND DISCUSSION

Results from OH mercury sampling are summarized in Table 1 and Table 2 for the baseline and monthlong test conditions, respectively.

Table 1. Baseline OH results^a.

Date	Run	Location	Total Hg, $\mu\text{g}/\text{Nm}^3$	Particulate-bound Hg, $\mu\text{g}/\text{Nm}^3$	Oxidized Hg, $\mu\text{g}/\text{Nm}^3$	Elemental Hg, $\mu\text{g}/\text{Nm}^3$
3/22/04	1	ESP In	7.79	2.21	0.46	5.11
3/22/04	1	ESP Out B	6.36	<0.00002	0.64	5.72
3/23/04	2	ESP In	7.41	1.86	2.12	3.43
3/23/04	2	ESP Out B	6.21	<0.00002	1.27	4.94
3/23/04	3	ESP In	6.68	2.08	0.96	3.65
3/23/04	3	ESP Out B	5.96	<0.00002	1.00	4.96

^a All values dry at 3% O₂.

Table 2. Monthlong OH results^a.

Date	Run	Location ^b	Total Hg, μg/Nm ³	Particulate-bound Hg, μg/Nm ³	Oxidized Hg, μg/Nm ³	Elemental Hg, μg/Nm ³
4/13/04	1.1	ESP In	8.76	6.16	1.25	2.74
4/13/04	1.1	ESP Out	3.21	0.00006	0.46	2.74
4/14/04	1.2	ESP In	8.72	5.57	0.87	2.28
4/14/04	1.2	ESP Out	3.38	0.00001	0.27	3.11
4/14/04	1.3	ESP In	9.48	7.44	0.67	1.37
4/14/04	1.3	ESP Out	2.92	0.00001	0.35	2.57
4/27/04	2.1	ESP In	8.17	3.45	0.92	3.80
4/27/04	2.1	ESP Out	3.15	0.0008	0.68	2.47
4/28/04	2.2	ESP In	8.50	4.96	0.42	3.11
4/28/04	2.2	ESP Out	3.57	0.00002	0.83	2.75
4/28/04	2.3	ESP In	8.08	5.27	0.54	2.26
4/28/04	2.3	ESP Out	3.42	0.00003	0.58	2.84
5/10/04	3.1	ESP In	6.50	1.34	0.73	4.43
5/10/04	3.1	ESP Out	3.43	0.000004	0.74	2.65
5/11/04	3.2	ESP In	6.39	0.53	0.77	5.09
5/11/04	3.2	ESP Out	2.88	0.0003	0.69	2.19
5/11/04	3.3	ESP In	5.86	0.59	0.36	4.91
5/11/04	3.3	ESP Out	2.83	0.00001	0.59	2.24

^a All values dry at 3% O₂.

^b B side of unit.

A summary of the Hg CEM results for the monthlong test is shown in Figure 3. The data were used to compute an hourly average for each valid hour of sampling data. A valid hour of sampling data contains data representing at least one half hour of sampling. The hourly average data was then averaged to obtain a daily average for each of the days with at least 12 valid hourly averages. The variability of the coal mercury can be seen in both the hourly and daily average inlet data. Control technologies tend to minimize the mercury variability at the outlet.

The results of the coal analysis are shown in Tables 3 and 4 for the baseline and monthlong tests, respectively. The coal mercury values, along with ultimate and heating value data, were used to calculate the equivalent concentration of mercury in the flue gas from the coal. These data along with the OH mercury data from the baseline measurements are summarized in Figure 4. The figure includes an average for these values along with a standard deviation for comparison. The mercury emissions from this unit were calculated from the outlet data to be 3.82 lb/TBtu for the baseline condition. The mercury removal calculated from the baseline data was 18%. This is higher than expected based on previous data.

Figure 3. Hg CEM Results

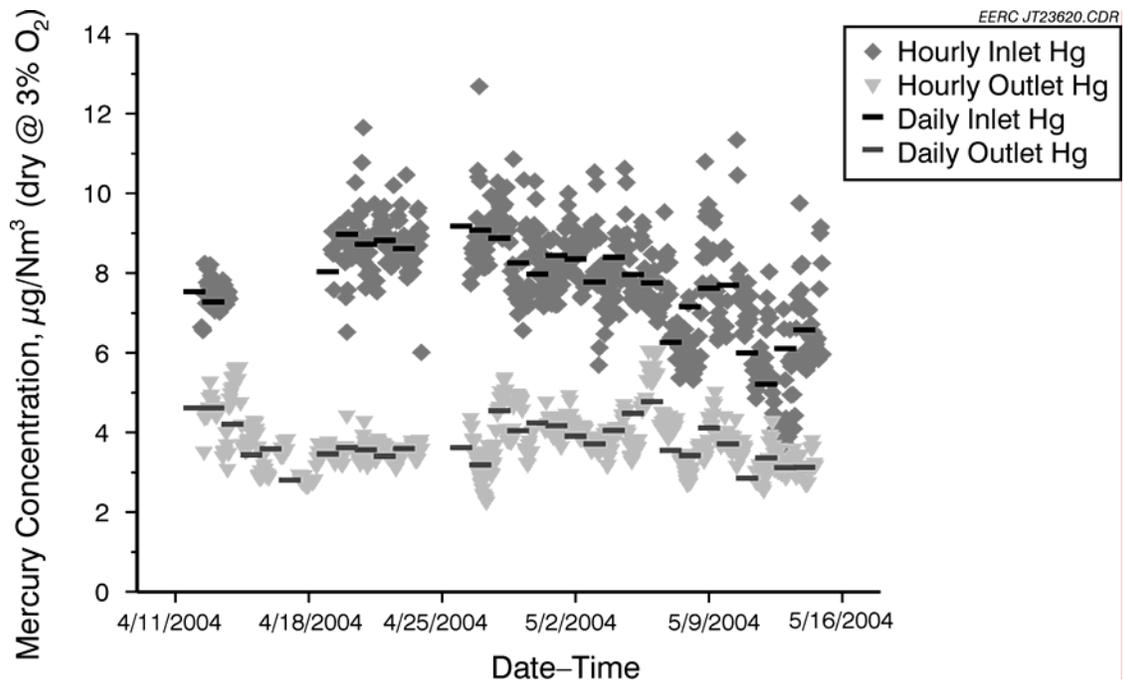


Table 3. Baseline coal analysis results^a.

Parameter	Date	3/22/04	3/23/04
	Time	13:00	11:00
Hg	µg/g (dry)	0.0453	0.0490
Cl	µg/g (dry)	12	16
Proximate			
Moisture	%	37.9	38.3
Volatile Matter	%	26.5	27.2
Fixed Carbon	%	26.4	26.4
Ash	%	9.2	8.1
Ultimate			
H	%	6.7	6.8
C	%	33.5	33.2
N	%	0.7	0.7
S	%	0.51	0.5
O	%	49.3	50.6
Heating Value	Btu/lb	6186	6307
F _d	dscf/TBtu	8646	8351
Flue gas Hg	µg/Nm ³ ^b	7.22	7.88

^a As-received unless otherwise noted.

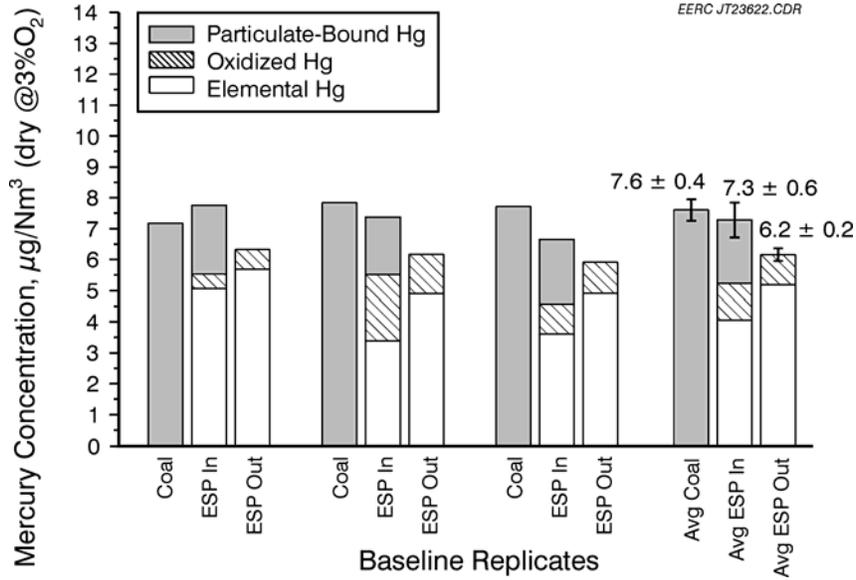
^b Calculated dry at 3% O₂.

Table 4. Monthlong coal analysis results^a.

Parameter	Date	4/12/04	4/13/04	4/14/04	4/26/04	4/27/04	4/28/04	5/10/04	5/11/04	5/12/04
	Time	13:05	11:00	10:50	11:20	13:15	8:55	8:20	8:25	9:30
Hg	μg/g	0.0685	0.0538	0.0668	0.0584	0.0582	0.0589	0.0426	0.0466	0.047
Cl	μg/g	9.3	6.4	6.4	14	11	12	12	12	15
Proximate										
Moisture	%	36.4	37.7	36.7	36.1	36.2	37.5	35.4	35.8	36.2
Volatile Matter	%	27.4	28.8	27.9	27.8	28.7	28.0	28.4	28.8	28.7
Fixed Carbon	%	28.4	23.7	26.6	26.5	27.6	26.6	27.3	27.3	27.3
Ash	%	7.8	9.8	8.8	9.6	7.5	7.9	8.9	8.2	7.9
Ultimate										
H	%	6.6	6.7	6.6	6.5	6.6	6.6	6.5	6.5	6.4
C	%	34.5	33.8	34.0	34.8	36.6	35.6	37.2	36.4	35.5
N	%	0.7	0.8	0.7	0.6	0.7	0.7	0.7	0.7	0.7
S	%	0.7	0.6	0.7	0.6	0.6	0.7	0.6	0.8	0.6
O	%	49.7	48.3	49.1	47.8	48.0	48.6	46.1	47.4	48.9
Heating Value	Btu/lb	6206	6184	6193	6428	6719	6492	6530	6551	6477
F _d	dscf/TBtu	8788	8811	8725	8606	8711	8731	9164	8876	8599
Flue gas Hg	μg/Nm ³ ^b	10.97	8.45	10.74	9.26	8.71	8.92	6.31	7.06	7.39

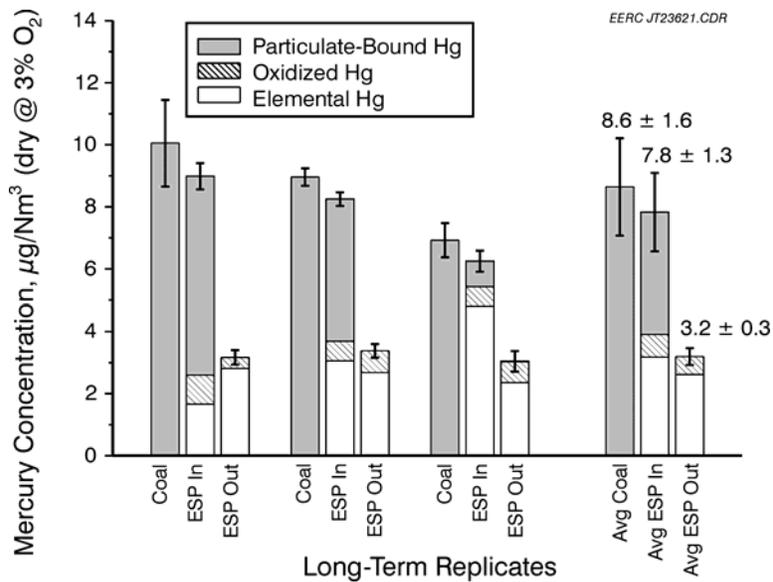
^a As received unless otherwise noted^b Calculated dry at 3% O₂

Figure 4. Baseline Mercury Results



The coal and OH mercury data from the monthlong test are summarized in Figure 5. The variability of the data is greater because of the longer time frame over which the data was collected and the corresponding variability in the coal mercury. The average mercury removal for the monthlong test was 63%. The average mercury concentrations from Side B of this unit over the monthlong test were extrapolated to calculate a theoretical mercury emission rate of 2.04 lb/TBtu.

Figure 5. Long-Term Mercury Results



Observations of plant operation during the testing did not indicate any effects of the technologies on unit operation. Special air-cooled corrosion probes placed in the flue gas for 4 weeks during testing showed no signs of abnormal deposition or corrosion.

CONCLUSIONS

The demonstrations of the technologies for mercury control successfully meet the target mercury removal of 55%. Ongoing is the interpretation of data to evaluate the balance of plant effects, including detailed corrosion probe analysis, and economics. Future work is aimed at a yearlong demonstration to better evaluate the balance of plant effects and refinement of economics.

ACKNOWLEDGMENTS

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