

SO₂ emissions can be controlled by switching to a low-sulfur coal or by post-combustion control technologies such as WFGD. Reducing emissions by switching to a low-sulfur coal, however, can adversely affect the performance of an electrostatic precipitator (ESP), the most common method of particulate control, because lowering the flue gas sulfur content increases the flyash resistivity, lowering the overall PM collection efficiency.¹⁰² A lowered PM collection efficiency would result in lower mercury removal.

On the other hand, a WFGD removes particulate matter and air toxics in addition to capturing SO₂. However, a WFGD control system also generates additional emissions of CO₂ (by chemical reactions that capture the SO₂) and a substantial amount of solid waste although some plants eliminate this problem by reclaiming the byproduct gypsum for use in wallboard manufacturing. Modeling evaluations indicate that power plants already equipped with a WFGD system can achieve mercury reductions at substantially lower costs.^{103,104}

For power plants burning eastern bituminous coals, the presence of an SCR system together with a WFGD system can achieve high levels of mercury reduction, and potentially eliminate the need for powdered activated carbon injection. The SCR systems also tend to oxidize some SO₂ into SO₃, which is a gas-conditioning agent that can improve the performance of an ESP. For plants without a WFGD, addition of a SCR appears to have little or no effect on mercury capture.

Due to the highly interactive nature of environmental control systems for SO₂, NO_x, Hg and CO₂, multipollutant control strategies will be more cost-effective. During the SO₂ and NO_x emissions control planning and implementation, the effects of the SO₂ and NO_x control systems/approaches on mercury control should be considered and the synergistic effects of these controls in mercury reduction should be exploited. Mercury control in a multi-pollutant control context can be more cost-effective than if it is considered alone.

Summary

The estimated costs for powdered activated carbon injection-based technology, which most likely will reach commercialization for mercury control before other technologies, is within the current control costs for NO_x. The results of the pilot tests of this technology indicate that implementation of more effective particulate control devices such as EPRI COHPAC, and use of more effective sorbents (such as composite PAC-lime) would further reduce these costs. Availability of less expensive sorbents (either through the impact of economies of scale on use of commercially available PAC or development of materials that are cheaper) would improve the economics of mercury control using this technology option. Another factor that can lower these control costs is the use of ultra fine sorbents.

As discussed above, the preliminary cost estimates on several other technologies, a number of which can be implemented on coal-fired plants with FGDs, indicate favorable economics compared to PAC injection-based control technologies. The superiority of oxidant-enriched calcium-based sorbents to powdered activated carbon has been confirmed at coal-fired boiler gas conditions typical of gas-cooled, semi-dry adsorption processes. Implementation of in-furnace injection of calcium-based sorbents (as discussed previously in this report) has been projected to be more cost-effective than PAC injection-based

¹⁰² We note that flue gas conditioning additives for addressing flue gas resistivity are under development and the results seem promising.

¹⁰³ For a comparison of mercury control costs using PAC injection for plants with and without FGD see Reference (2).

¹⁰⁴ The ICR data and other publicly available information also support this conclusion.



technologies because the cost of limestone is typically an order of magnitude lower than the cost of activated carbon.

Implementation of multi-pollutant control technologies enhances cost-effectiveness. Additionally, the impact of technologies traditionally used for control of single pollutants on emissions and control costs of other pollutants of concern should be considered. Many control devices that are used for SO₂, NO_x, and PM control can provide the co-benefit of mercury control. In a multi-pollutant control approach, such as that provided by 310 CMR 7.29, mercury control costs should be considered in the context of the overall emissions reduction and control costs of all pollutants. The synergistic effects of the interactions between various control technologies should be exploited in evaluation of emissions and costs. The economics of mercury control can be more favorable in this context.

Improved sorbents and other methods for controlling mercury and multi-pollutant emissions are under development by DOE, EPA, EPRI, the electric industry, and the utility vendors. These activities include large-scale programs focused on full-scale demonstrations of PAC injection technologies. As a result of these research and development activities, mercury and multi-pollutant control options are expected to become available with improved cost-effectiveness (the status of each technology regarding its development/commercialization stage has been discussed in the specific relevant technical subsections in Appendix A, under Mercury Control And Control Technology, of this report).

Although every pollution control technology/system cannot reasonably be implemented on every plant configuration, an examination of the available and emerging control technologies indicates that control of mercury can be achieved cost-effectively for various plant conditions and configurations in the near future. Clearly, a key factor in the availability of viable control technologies and the feasibility of the control costs is the level of mercury control that would be required.



Appendix B References

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APPENDIX C: TECHNOLOGY OPTIONS FOR COMPLIANCE DEMONSTRATION

Facilities subject to 310 CMR 7.29 will need to demonstrate compliance with the Hg standards to be proposed by the Department in Spring 2003. The compliance demonstration that will be required will, of course, be closely tied to the form of the standard. Even though a standard has not yet been proposed, it is, nevertheless, possible to provide a general overview of the measurement technologies and methods that are available to measure Hg both in coal and in stack emissions. One or more of these methods are likely to be required in order to demonstrate compliance with whatever standard is adopted.

The following are some of the compliance demonstration methods that are representative of various technologies. Each of these methods may be used alone or in combination with other methods, depending on the parameters to be measured and the standard that is to be met:

- sampling of Hg in coal
- material balance [Hg in coal samples-Hg in samples of non-gaseous coal combustion residues (CCRs)]
- emissions tests at a frequency to be specified in the standard, possibly at the stack, possibly at both the stack and ESP inlet
- integrated sampling of emissions over an extended time period using absorption media
- continuous emissions monitoring systems (CEMS) to monitor stack-level Hg emissions, averaging the data over a time period to be specified in the standard.

The methods vary as to the parameters measured. For example, the sampling of Hg in coal, material balance and extended period integrated sampling measure total Hg only, not speciated Hg. The emissions tests or CEMS could be used to demonstrate compliance on a total Hg basis and/or for each chemical species of Hg, as necessitated by the standard to be proposed.

The level of experience with various compliance methods also varies. Facilities and stack testing companies have extensive experience with sampling of Hg in coal and with Hg stack testing, due to EPA's 1999 Mercury Information Collection Request (ICR) and due to the Hg testing requirements established by DEP's 310 CMR 7.29 regulation. However, U.S. facilities have little to no experience with sampling of Hg in certain CCRs, integrated Hg sampling or Hg CEMS; the state of the technology for these three methods is discussed in greater detail below.

Sampling of Hg in CCRs

There are some 15 categories of non-gaseous CCRs; the actual number of categories at any particular facility is dependant on its specific operating characteristics. Tests methods to determine the amount of Hg present in most CCR categories have been developed, but the overall approach is problematic because of the difficulty of attempting to take samples of each CCR over a comparable time frame in order to assure a correct mass balance. The mass balance approach generally has been presented as a research dilemma, not as a practical compliance demonstration approach.

Integrated Hg Sampling

This sampling method has been suggested by the Electric Power Research Institute (EPRI) in the hope that it would prove less expensive than Hg CEMS. The absorption method entails placing a charcoal absorbing medium in the path of the gaseous emissions, removing the sample after a given time period, and quantifying the Hg contained in the sample. The approach assumes that the Hg standard proposed will have a "long" averaging time (on the order of weeks rather than hours), thusly producing a "small" number of samples per year. The approach was tested concurrent with EPA testing of Hg CEMS at a coal-fired boiler unit, but the Department is not aware of any of the resulting data having been made



available to the public at this time. One drawback of the approach is that the sample is not proportional, i.e., there is no way to account for the actual flow rate seen by the sample due to varying unit loads over time; this is in contrast to stack testing methods which require isokinetic sampling to ensure a representative stack sample is analyzed.

EPA's Environmental Technology Verification Hg CEMS Tests

Hg CEMS has been the focus of great attention as a possible compliance demonstration approach and, therefore, the remainder of this section will discuss issues related to Hg CEMS. The US EPA, working with other agencies, has been investigating Hg CEMS, in the following series of projects:

ETV Phase I – Pilot-Scale Verification of Continuous Emission Monitors for Hg

EPA's Office of Research and Development, National Exposure Research Laboratory (NERL), in coordination with EPA's Environmental Technology Verification (ETV) program, and with funding from the Massachusetts Department of Environmental Protection, conducted Hg CEMS pilot scale tests in North Carolina in January 2001. The Advanced Monitoring Systems Center, one of six technology centers under ETV, is operated by Battelle in cooperation with EPA. Battelle tested 4 commercially available Hg CEMS at the Rotary Kiln Incinerator Simulator, a pilot scale combustion facility at the Environmental Research Center, a part of EPA's National Risk Management Research Laboratory at Research Triangle Park, North Carolina. The Hg CEMS were considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor.

The CEMS were tested over a two-week period, with Week 1 simulating lower-level emissions typical of a coal-fired power plant and Week 2 simulating higher-level emissions typical of a municipal waste combustor. The statistical data tests performed included:

- relative accuracy as compared to the Ontario Hydro (OH) Method;
- correlation with the reference method;
- precision at stable flue gas conditions;
- calibration/zero drift; sampling system bias;
- interference effects of flue gas constituents;
- response time to changing Hg levels;
- response to low levels of Hg;
- data completeness; and
- setup and maintenance needs.

Features of each CEMS and the relative accuracy found at the levels typical of a coal-fired power plant follow; full statistical results of testing are available¹⁰⁵. For comparison, when CEMS were first used for pollutants such as NO_x and SO₂, a relative accuracy of up to 20% was considered acceptable; in addition, the current draft performance specification for mercury CEMS keeps 20% as the acceptability limit. Each monitor description states whether the monitor requires chemicals to operate (monitors requiring chemicals are considered "wet;" monitors not requiring chemicals are considered "dry"). "Dry" monitors offer lower ongoing operation costs and simpler operation, and are therefore preferable. The following CEMS were tested:

- *PS Analytical's Sir Galahad II* is a continuous monitor that measures elemental Hg and total vapor phase Hg using an aqueous reagent to convert oxidized Hg to elemental Hg. The monitor must be supplied with aqueous reagent and Argon gas. SG-II provided an accuracy relative to the OH method of 20.6% for total mercury, at total mercury levels of about 7 to 8 µg/m³. Testing

¹⁰⁵ See <http://www.epa.gov/etv/verifications/vcenter1-11.html>



showed relative accuracy of 22.8% for elemental mercury, and 27.2% for oxidized mercury at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu\text{g}/\text{m}^3$.

- *Lumex Ltd.'s Lumex Mercury CEM* is a real-time continuous monitor that determines elemental and total Hg using catalytic pyrolysis to decompose oxidized Hg to elemental Hg, and cold vapor atomic absorption spectroscopy (CVAAS) to detect elemental Hg. The monitor uses no wet chemical reagents or external gas supplies. The Lumex CEM provided accuracy relative to the OH method of 58.2% for total mercury, at levels of about 7 to 8 $\mu\text{g}/\text{m}^3$. Testing showed relative accuracy of 50.2% for elemental mercury, and 99% for oxidized mercury, at elemental mercury levels of about 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of about 1 to 1.5 $\mu\text{g}/\text{m}^3$.
- *Nippon Instrument Corp.'s Model AM-2* measures elemental Hg by removing the oxidized Hg with distilled water and using a gold amalgam trap to capture the elemental Hg with subsequent CVAAS to detect elemental Hg. The monitor consumes no chemicals or gasses, except purified air. The Nippon AM-2 provided relative accuracy for elemental mercury of about 14% relative to OH results, at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$.
- *Nippon Instrument Corp.'s Model MS-1/DM-5* is a continuous monitor that measures elemental and oxidized Hg using de-ionized water to reduce oxidized Hg to elemental Hg and CVAAS to detect the elemental Hg. The monitor requires no external gas supplies. The MS-1/DM-5 provided accuracy relative to the OH method of 13.2% for total mercury, at total mercury levels of about 7 to 8 $\mu\text{g}/\text{m}^3$. Testing showed relative accuracy of 11.0% for elemental mercury and 54.9% for oxidized mercury, at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu\text{g}/\text{m}^3$.

Some of these commercially available monitors achieved the desired 20% relative accuracy; modifications to the monitors are anticipated, with the goal of improving accuracy in the subsequent testing phases discussed below.

ETV Phase II – Field Demonstration of Hg Continuous Emission Monitors

EPA's ETV program in coordination with DOE's Mixed Waste Focus Area conducted Hg CEMS field tests at a hazardous waste combustor in Tennessee in August-September 2002. ETV/Battelle and DOE tested four commercial Hg CEMS at DOE's Toxic Substances Control Act Incinerator test facility in Oak Ridge, Tennessee. The facility burns hazardous and low-level radioactive waste. The Hg CEMS were considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor. Mercury emissions levels were expected to be comparable with those from coal-fired power plants. The same type of statistical data tests were to be performed as in Phase I. Participating vendors include: EnviroMetrics, PS Analytical, Nippon Instruments Corp. (2 instruments) and OPSIS AB. The instruments from PS Analytical and Nippon were also tested in Phase I. The results of the Phase II tests are expected to be available in March 2003.

ETV Phase III – Testing to be conducted at a coal-fired power plant

ETV hopes to receive funding to conduct a third phase of testing at a coal-fired power plant.

ETV's Multi-Metals CEMS Verification

EPA's ETV program verified the performance of a Multi-Metal CEMS at the U.S. Army's Construction Engineering Research Laboratory at its Tooele, UT Army Depot demilitarization incinerator in May 2001. *Cooper Environmental Services' XCEM* is an x-ray based CEM for multiple metals. The XCEM collects particulate matter and gaseous Hg on a filter tape, then subjects the collected material to X-ray



fluorescence analysis. The collection and analysis steps are automated to provide continuous measurement of emitted metals. The verification test was conducted in collaboration with the U.S. Army's Construction Engineering Research Laboratory at its demilitarization incinerator at the Tooele, UT Army Depot. Metal solutions containing Hg and other metals were spiked into the flue gas. The XCEM was evaluated for: accuracy relative to EPA Method 29; correlation with Method 29 results; precision; response time; zero, span, and internal standard drift; and other factors. Relative accuracy (RA) results for Hg are summarized here; full statistical testing results are available¹⁰⁶. XCEM Hg readings were very low at the start of each test day, rising gradually until they stabilized. The best agreement of XCEM and M29 Hg results (within about 20%) was found with M29 runs conducted late in the test day, when XCEM readings had stabilized.

EPA's Office of Air Quality Planning and Standards Field Hg CEMS Tests

EPA's Office of Air Quality Planning and Standards (OAQPS) has been conducting Hg CEMS field tests at a coal-fired utility unit since August 2001. OAQPS, like ETV, is performing three phases of work, of which the first phase is complete, and the second phase is in process. OAQPS may conduct a third Hg CEMS testing phase to obtain additional information. The current OAQPS tests represent the test of the majority of commercially available Hg CEMS. The Hg CEMS are considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor. The test facility chosen by OAQPS (a 140 MW tangentially-fired pulverized coal boiler with cold-side ESP, burning eastern bituminous coal) is similar to the coal-fired units in Massachusetts subject to 310 CMR 7.29.

OAQPS Phase 1

After selecting a test facility, OAQPS' main activities and achievements from May 2001 to March 2002 were to:

- verify availability and stability of elemental and oxidized Hg standards for detector and sample handling system instrument field calibration,
- conduct Relative Accuracy Test Audits (RATAs) with the Ontario Hydro Method, and
- collect data for 3 months on performance criteria.

The best Phase 1 results were on a Hg CEMS utilizing a wet chemical converter, which had a relative accuracy (RA) of 9.5% on 10 of 15 runs. For comparison, when CEMS were first used for pollutants such as NO_x and SO₂, a RA of up to 20% was considered acceptable; in addition, the current draft performance specification for mercury CEMS keeps 20% as the acceptability limit. The best Phase 1 results on a Hg CEMS utilizing a dry converter showed a materially improved performance on its second RATA after modifications to its converter. In general, it would be preferable to utilize dry CEMS instead of wet, to avoid issues associated with the handling of wet chemicals.

OAQPS Phase 2

OAQPS' main activities from June 2002 to December 2002 were to:

- resurvey vendors to locate more participants
- acquire and install 2 additional dry converter Hg CEMS, as well as further modify a dry converter-based Hg CEMS tested in Phase 1
- relocate a wet converter Hg CEMS tested in Phase 1 to trailer
- add EPRI's integrated sample monitoring system for concurrent testing with the initial Phase 2 RATA (i.e., the third RATA overall)
- complete the third RATA series

¹⁰⁶ See <http://www.epa.gov/etv/verifications/vcenter1-20.html>



- add another two dry converter Hg CEMS, one using plasma emission spectroscopy, a different measurement technology than the other Hg monitors tested
- plan a fourth RATA series

Although EPA has indicated that preliminary Phase 2 data include results that positively track test method and monitor values, the full report detailing the results is not expected until May 2003.

OAQPS Phase 3

OAQPS may conduct a third phase of testing to obtain information on additional source configurations expected to have controls more comparable with what regulations such as the utility MACT or those developed from multi-pollutant legislation may contain (e.g., a bituminous fired unit with wet scrubber and ESP, or a subbituminous fired unit with secondary emission controls such as SCR or SNCR, or a unit with adsorbent injection with a hot side ESP), on additional sampling locations (i.e., at the inlet to the control device), on additional Hg CEMS models (such as the Cooper Environmental Services XCEM mentioned above), or to obtain additional Hg CEMS operating time data.

Costs

Costs for certain Hg compliance determination options are known, while others are not. Capital costs of Hg CEMS have been estimated by a number of vendors to be in the range of \$60,000. In addition, there would be on-going equipment and personnel costs to maintain a CEMS (though most large power plants already have staff dedicated to CEMS that would presumably take on Hg CEMS maintenance as part of general CEMS responsibilities). The costs for coal sampling or stack testing are known on a per-test basis (i.e., \$100-150 per coal sample and \$15,000-40,000 per inlet/outlet stack test), but the total cost would depend on the actual number and type of samples or tests ultimately required by the regulation. The Department is not aware of any cost information for extended period integrated samplers, nor do we have information on the costs to measure Hg in each type of CCR.

Summary

The Department evaluated options that might be used by facilities to demonstrate compliance with a mercury emission standard. The specific compliance demonstration technique used must be selected in concert with the form of the emissions limit in the standard and will be considered during development of the Department's proposed standard. There are approaches currently commercially available to allow facilities to demonstrate compliance with a mercury emission standard, including fuel and emissions sampling. In addition, mercury CEMS can be purchased from monitor vendors at the present time. The most accurate Hg CEMS currently available are of the "wet" type. Some of the commercially available monitors achieve the desired 20% relative accuracy, though modifications to the monitors are anticipated, with the goal of improving accuracy. Research into "dry" CEMS is ongoing, and will be followed by the Department as it develops a mercury standard. The results of a number of new mercury CEMS studies are expected between March and May 2003, and will provide more information about emerging mercury CEMS approaches.



APPENDIX D: WASTE ISSUES RELATED TO MERCURY CONTROL

It is possible that facilities subject to 7.29 will install controls for mercury that would change the ultimate fate of mercury originating in the coal burned at the facilities. It is expected that some controls installed to meet the NO_x and SO₂ requirements of 7.29 will change the ultimate fate of mercury originating in the coal burned at the facilities. This section discusses some issues related to the fate of mercury from coal.¹⁰⁷

Background

When coal is burned in a boiler, the mercury contained in the coal either is emitted from the stack as a gaseous air pollutant, or ends up in the major high-volume¹⁰⁸ coal combustion residues (CCRs): fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) wastes. Fly ash is the particulate matter that is light enough to be carried out of the boiler, and to subsequently be either captured by air pollution control equipment such as Electrostatic Precipitators (ESPs) and Fabric Filters (FFs) or emitted from the stack. Bottom ash is unburned material that is too heavy to be carried out of the boiler, and therefore falls to the bottom of the boiler. Boiler slag is unburned material that falls to the bottom of the boiler and then melts, forming slag upon cooling. FGD wastes are formed by SO₂ air pollution control equipment.

The specific emissions control technologies used by eight coal-fired units subject to 310 CMR 7.29 and the current quantity and fate of ash generated by those units is discussed below.

Current and expected emissions controls on MA coal-fired units

All eight coal fired units subject to 7.29 are currently equipped with coal-side ESPs. None of the units are currently equipped with FGD; however, 7.29 Emission Control Plan (ECP) approvals for two facilities include future installation of FGD. Wet FGD is to be installed on Brayton Point unit 3, and dry FGD is to be installed on Salem Harbor units 1 and 3. The three coal-fired units at Salem Harbor and the one at NRG Somerset currently use Selective Non-Catalytic Reduction (SNCR) for NO_x control. The 7.29 ECP approvals for Brayton Point units 1 and 3 and Salem Harbor units 1, 2, and 3 include future installation of Selective Catalytic Reduction (SCR).

Coal ash generated by MA coal-fired units in 2001

The current quantity and fate of coal ash generated by the eight coal-fired units subject to 310 CMR 7.29 are listed in the following table. Even in the absence of 310 CMR 7.29, changes in disposal practices at some facilities were expected, due to efforts by some communities to limit the disposal of fly ash in local landfills.

¹⁰⁷ Much of this information is taken from "Characterization and Management of Residues from Coal-Fired Power Plants, Interim Report" United States Environmental Protection Agency, Office of Research and Development, Washington, DC 20460, EPA/R-00/XXXX, February 13, 2002.

¹⁰⁸ There are numerous "low-volume" categories of CCRs, see op. cit. page 2-7.



Table D-1. Quantity and fate of coal ash generated by MA coal-fired units in 2001.

	Fly Ash	Bottom Ash	Total	landfilled	recycled
	Wet basis tons				
Brayton Point ¹⁰⁹	369,139	44,364	413,503	54.8% ¹¹⁰	45.2% ¹¹¹
Salem Harbor	134,476.56	1818.28	136,294.84	100% ¹¹²	
Mt. Tom			59,165	95.6% ¹¹³	4.4% ¹¹⁴
NRG Somerset			27,000		100% ¹¹⁵

Potential Waste Stream Changes After Installation of Controls

The mercury control strategy implemented at a facility may have an effect on 1) the quantity of waste produced by a facility, 2) the mercury content of the waste produced, and 3) the chemical properties of the wastes produced, including the availability of mercury.

Waste Quantity

One mercury control device under investigation injects activated carbon (or other sorbents) into the flue gas, increasing the amount of material ultimately collected by the particulate control device. The amount of carbon used is a function of 1) the mercury content of the flue gas, including chemical speciation 2) the mercury reduction sought, 3) the type of carbon injected, and 4) the composition and temperature of the flue gas.

Another possible mercury control device is to add a polishing filter after an existing ESP. Such an approach would increase the amount of fly ash caught, thereby decreasing particulate emissions, including the portion of mercury associated with the particulate.

Alternatively, switching fuels from coal to a lower-ash content fuel is a mercury control strategy that would reduce the overall quantity of ash generated.

It is also possible to clean coal of mercury and other substances before combustion. Most coal cleaning processes are based on the principle that coal is less dense than the pyritic sulfur, rock, clay, or other ash-producing impurities imbedded in it, decreasing the production of CCRs from the boiler. Coal cleaning also affects mercury emissions, as discussed in the following section.

The control devices proposed for SO₂ control at Brayton Point and Salem Harbor will have an effect on the quantity of waste produced by the facilities (there are also mercury emission implications of FGD controls, as discussed in the following section). Dry FGD systems inject a substance that absorbs SO₂, with the resulting dry reaction product collected with the fly ash by a particulate air pollution control device. Wet FGD systems inject a slurry of water and a sorbent, which results in greater capture of SO₂ than in a dry FGD, but with a greater volume of waste produced.

¹⁰⁹ Assumes 30% water content.

¹¹⁰ In Pennsylvania, Maine, Massachusetts and New Hampshire.

¹¹¹ Brayton Point's recycled ash was used as flowable fill and as a cement substitute in concrete.

¹¹² In Maine, Massachusetts and New Hampshire.

¹¹³ In Massachusetts.

¹¹⁴ Mt. Tom's recycled ash was used to cap a landfill in Massachusetts.

¹¹⁵ Based on 1998 data, NRG's recycled ash was used as landfill daily cover, flowable fill, and as a cement substitute in concrete.



Mercury Content of Waste

Coal cleaning reduces the concentration of mercury in combusted coal because the pyrite that is removed contains higher levels of mercury than does the rest of the coal. When mercury is removed from coal before combustion, the amount of mercury in CCRs and stack emissions, in total, decreases. Coal cleaning entails a transfer of mercury from CCRs and emissions to coal cleaning wastes. One coal cleaning waste component of particular concern is pyrite, which has been associated with acid generation within waste management areas, often requiring isolation from water and oxygen.

The intent of many mercury control strategies is to capture mercury instead of allowing it to be emitted from coal-fired units. EPA has estimated that, nationwide, the mercury concentration in CCRs will change in the future due to installation of mercury, NO_x and SO₂ control devices. Because control devices were assumed to be installed after the boiler, mercury concentrations in bottom ash and boiler slag are not predicted to change. EPA's estimates of the change in mercury concentration in CCRs are in Table D-2, below.

Table D-2. Comparison of Current Versus Predicted Future Mercury Concentrations in CCRs Based on Mass Balance Calculations¹¹⁶

CCR	Average Mercury Concentration (ppm) ^a	
	1999 ^b	2010 (Projected)
Fly ash	0.33	0.81
Bottom ash	0.065	0.065
Boiler slag	0.041	0.041
FGD residue	0.22	0.49

a All values to 2 significant digits.

b 1999 values based on mercury input of 75 tons and stack emissions of 48 tons (i.e., capture efficiency of 36%). [2010] values are based mercury input of 82 tons and stack emissions of 12 tons (i.e., capture efficiency of approximately 85%).

Wet FGD scrubbers have been found to capture mercury, but with a wide range of capture efficiencies. It is believed that the concentration and species of mercury in the flue gas influences capture efficiencies; specifically, subbituminous coals seem to generate a higher proportion of difficult-to-capture elemental mercury than bituminous coals. All eight coal-fired units subject to 7.29 burn bituminous coal.

Chemical Properties of Wastes

Two questions of interest are: how will chemistry affect beneficial uses? and will the mercury captured by control devices ultimately be available for leaching after disposal?

The first question is largely one of the effect of carbon on re-use of CCRs. Generally, installation of low-NO_x burners can increase the amount of carbon in ash (also known as Loss on Ignition (LOI)), which directly affects the ability to re-use ash as a substitute for cement in concrete. While this effect is of concern nationally, Massachusetts facilities have already installed low-NO_x burners to comply with the NO_x RACT requirements of 310 CMR 7.19, so the effects of low-NO_x burners on ash chemistry have already been felt in Massachusetts. Similarly, mercury control achieved by injecting carbon into the flue gas increases the amount of carbon in the captured fly ash, with the same potential effect as low-NO_x burners of making the ash unsuitable for use as a cement substitute. Various ash reburn approaches have been proposed, in order to recover energy from ash when high carbon levels are left in the ash. If ash from mercury control devices (containing higher mercury levels) were subsequently reburned in an uncontrolled combustion device, the mercury previously captured would be released to the atmosphere, negating the benefit of the mercury control device.

¹¹⁶ Op. cit. page ES-4.



The second question is whether CCRs disposed of in a landfill or recycled in some form of beneficial use could release mercury to the environment. EPA has analyzed this question for a number of disposal and use approaches, and found that the major categories of disposal and use appear to release little mercury to the environment, but that specific uses are a cause for concern.

Disposal and uses that appear to release little mercury via leaching and volatilization include:

- cement substitute in concrete
- flowable fill
- structural fill
- road base/subbase
- landfill disposal

Uses that appear to have the potential for mercury release via leaching and volatilization include:

- cement kiln fuel
- mineral filler in asphalt
- snow and ice control
- blasting grit/roofing granules
- wallboard (leaching not significant, volatilization may be significant)
- waste stabilization/solidification (volatilization probably not significant, leaching may be significant)
- agriculture

Use of ash in mining remediation applications may result in mercury leaching; however, it may be that more mercury can be leached to the environment if no remediation is done than if CCRs are used.

Legal framework for proper disposal of coal ash: federal, state, local

Federal

Ash disposal is regulated under the federal Resource Conservation and Recovery Act (RCRA)'s Subtitle D solid waste provisions. EPA concluded in a May 22, 2000 Federal Register Regulatory Determination that regulation of ash as a hazardous waste under Subtitle C was not warranted, but that regulations should be established for certain disposal techniques, including use of CCRs to fill underground mines.

State

Massachusetts has jurisdiction over coal ash disposed of in Massachusetts landfills. Coal ash that is disposed of in a landfill in Massachusetts is defined as a solid waste. However, an exemption was added to the Solid Waste Statute (Massachusetts General Law Chapter 111, Section 150A) in the 1970s that specifically exempted various uses of coal ash, as follows:

“Ash...shall not be construed as refuse...under this section when used as a raw material for concrete block manufacture, aggregate, fill, base for road construction, or other commercial or industrial purpose, or stored for such use.” “....provided, further, that no final disposal of ash produced by the combustion of coal may be accomplished by burial of such ash in the ground, other than as base for road construction or fill, unless the place where such disposal takes place has been assigned for such disposal by the board of health and plans for such disposal have been approved by the department pursuant to this section. The department may waive the requirements of the preceding paragraphs as they may apply to the disposal of burial of ash...”



Therefore, coal ash that is used in products such as concrete, or as a fill material in certain circumstances, is exempt from management as a solid waste. This statutory exemption is still in effect in Massachusetts.

Local

Coal ash disposal landfills are required to obtain a site assignment and a permit. The local Board of Health issues the site assignment and DEP issues the permit. However, where coal ash is used as a “fill” material, there is no site assignment issued by the local Board of Health or permit issued by DEP.

Recently, several municipalities in Massachusetts have passed bylaws banning disposal of ash within their respective towns. However, depending on how the bylaws were written, some of these bylaws may not be valid. The Solid Waste Act of 1987 included a provision that disallows a town from passing a bylaw after July 1, 1987 that would have the effect of banning landfills from an area where the land was already zoned industrial, except specifically to protect a town’s public drinking water supply.

Summary

Certain mercury emission reduction approaches will affect the quantity of waste produced, its mercury concentration, and its chemical properties. The Department believes that there are currently, and will continue to be, safe options for the disposal or management of waste generated from coal-fired power plants. The Department will continue to consider issues such as landfill capacity and ultimate fate of mercury, including water quality and coal ash re-use options, as it develops a mercury standard.



APPENDIX E: 310 CMR 7.29 EMISSION CONTROL PLAN SUMMARIES FOR COAL-FIRED FACILITIES

For reference, the pollution control measures listed in the 310 CMR 7.29 Emission Control Plan (ECP) approvals issued June 7, 2002 for the coal-fired Massachusetts facilities subject to 310 CMR 7.29 are summarized below. The June 7, 2002 ECP approvals were for the initial 310 CMR 7.29 applications submitted by the facilities; some facilities have since revised their applications, but no modified ECP approvals have been issued as of the writing of this report.

Key Highlighted text in the second column indicates new equipment or a new pollution control technique expected to be installed or utilized. Plain text indicates existing equipment or an existing pollution control technique.

Facility Name	Emission Control Plan Summary
Holyoke Water Power Company Mt. Tom Station	Single Unit Facility Proposed Pollution Control Technique(s): Management of Lower Sulfur Fuels (Conversion to cleaner Coals) Upgraded combustion controls and burner system – NO_x control Selective Non-Catalytic Reduction – NO_x control Electrostatic Precipitators – PM control SO₂ Early Reduction Credits SO₂ Acid Rain Allowances Off-site CO₂ Reductions
PG&E Salem Harbor Station	Multi Unit Facility Proposed Pollution Control Technique(s): Units 1 and 3 – Low NO_x Burners Selective Catalytic Reduction – NO_x control Combustion Tuning and Controls – NO_x control Electrostatic Precipitators – PM control Management of Lower Sulfur Fuels Dry Flue Gas Desulfurization with Fabric Filter – SO₂ controls Unit 2 – Low NO_x Burners Selective Catalytic Reduction – NO_x control Combustion Tuning and Controls – NO_x control Electrostatic Precipitators – PM control Management of Lower Sulfur Fuels Unit 4 – Low NO_x Burners Combustion Tuning and Controls – NO_x control Electrostatic Precipitators – PM control Management of Lower Sulfur Fuels Off-site CO₂ Reductions



PG&E Brayton Point Station	Multi Unit Facility Proposed Pollution Control Technique(s): Unit 1 – Selective Catalytic Reduction – NO_x control Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Overfire Air Management of Lower Sulfur Fuels Unit 2 – Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Overfire Air Management of Lower Sulfur Fuels EPRICON Flue Gas Conditioning – SO₂ control Unit 3 – Selective Catalytic Reduction – NO_x control Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Over fire Air Management of Lower Sulfur Fuels Wet Flue Gas Desulfurization – SO₂ control A new taller stack Unit 4 – Electrostatic Precipitators – PM control Low NO_x Burners Management of Lower Sulfur Fuels Flue Gas Recirculation – NO_x control Off-site CO₂ Reductions
NRG Somerset Station	Single Unit Facility Proposed Pollution Control Technique(s): Natural Gas Reburn Management of Lower Sulfur Fuels (Reduced sulfur coal) Selective Non-Catalytic Reduction – NO_x control Overfire Air Ports – NO_x control Electrostatic Precipitators – PM control SO₂ Early Reduction Credits SO₂ Acid Rain Allowances Off-site CO₂ Reductions On-site CO₂ Reductions



APPENDIX F: FIELD DEMONSTRATION OF MERCURY CONTROL USING ACTIVATED CARBON INJECTION CONTROL TECHNOLOGIES

Under the auspices of the Department of Energy (DOE) National Energy Technology Laboratory, studies of mercury control devices are occurring across the US. One study of particular relevance to Massachusetts includes testing at four facilities: Alabama Power's Gaston unit 3, Wisconsin Power's Pleasant Prairie unit 2, and two Massachusetts units subject to 310 CMR 7.29, i.e., Brayton Point unit 1 and Salem Harbor unit 1. This study is being conducted by ADA Environmental Solutions (ADA-ES), LLC, with primary funding from DOE and additional funding from ADA-ES, EPRI, facility owners (PG&E National Energy Group in the case of Brayton Point and Salem Harbor Stations), and others. The goals of the study are:

- to perform the first full-scale evaluations of mercury control on coal-fired boilers (up to 150 MW equivalent),
- to evaluate effectiveness of sorbent-based mercury control (i.e., activated carbon),
- to test several different power plant configurations, and
- to document all costs associated with mercury control.

Testing was conducted at Gaston in Spring 2001, Pleasant Prairie in Fall 2001, Brayton Point in Summer 2002, and testing at Salem Harbor Station is to be completed in November 2002. ADA-ES has indicated that the final report on all four facilities will not be ready before summer 2003, however, some preliminary data is available, as discussed for each facility below.

At each facility, ADA-ES conducts Baseline, Parametric and Long-term testing. Baseline testing documents mercury concentrations with no Activated Carbon Injection, using Ontario Hydro testing and a semi-continuous emission monitor (S-CEM). Parametric testing consists of a series of 8 hour tests over three weeks at different parametric conditions (i.e., sorbent, feedrate, and operating conditions); mercury concentrations are documented using a S-CEM only. Long-term testing consists of a ten day run at constant conditions using optimum sorbent and feedrate; mercury concentrations are documented using Ontario Hydro testing and a S-CEM.

The Apogee Scientific semi-continuous emission monitor (S-CEM) used to measure mercury concentrations is a research prototype analyzer that requires a skilled operator. It determines total vapor phase mercury measurements, converting all non-elemental vapor-phase mercury in the flue gas to elemental mercury and measuring using cold vapor atomic absorption spectrometer with a gold amalgamation system. Particulate is separated from the gas sample by a filter. Baseline data collection is performed to compare the accuracy of the S-CEM against the Ontario Hydro test method and to determine baseline Hg concentrations. At Brayton Point, the S-CEMs were placed before the old ESP, before and after the new ESP, and at the stack. At Salem Harbor, the S-CEMs were placed at the economizer/Air Pre-Heater exit, the ESP inlet, and the ESP outlet (ID fan inlet).

Gaston testing

Gaston's Unit 3 is a 270 MW wall-fired boiler that burns washed eastern US low sulfur bituminous coal. Particulate matter emissions are controlled by a Research Cottrell hot-side (i.e., before the air preheater) ESP followed by a Hamon Research-Cottrell COMPACT Hybrid Particulate Collector (COHPAC) baghouse. This unit was chosen for testing because the COHPAC represents a cost effective retrofit solution for utilities with existing ESPs. The sorbent was injected downstream of the ESP and the air preheater and upstream of the baghouse. A comparison of the Gaston results with those of the other two completed sites, Pleasant Prairie and Brayton Point, indicated that Gaston showed the highest percentage of mercury removal (i.e., 90+% removal) at the lowest concentration of sorbent injected (i.e., less than 5 lb/million actual cubic feet (lb/MMacf)) of the three units tested to date. This result is also reflected in



cost data indicating Gaston has the highest mercury removal (i.e., 90+% removal) with the lowest sorbent costs at that removal level (i.e., under 0.5 mills/kWh). ADA-ES would like to perform longer-term powdered activated carbon testing on Gaston's Unit 3 in 2002-2003.

Pleasant Prairie testing

Pleasant Prairie unit 2 is a 600 MW turbo fired boiler equipped with a cold-side (i.e., after the air preheater) ESP and a Wahlco SO₃ system for fly ash resistivity control. This facility burns Powder River Basin (PRB) subbituminous coal, unlike any other facility in the test program, and unlike any Massachusetts facility subject to 310 CMR 7.29. The facility was selected to include a PRB-fired unit, but the results may not be directly applicable to Massachusetts facilities that do not burn PRB. The best preliminary data from this unit indicate a 73% mercury removal upon injection of sorbent, an increase from the 5.3% removal seen without sorbent injection. The results indicated a clear "plateau" of mercury removal, in which no further mercury removal is seen even upon increasing the sorbent injection rate. Likewise, the sorbent costs at this facility increase at higher sorbent injection rates, for no further addition in mercury removal. Sorbent costs of approximately 0.5 mills/kWh achieve mercury control of approximately 58%, while a doubling of sorbent cost to 1 mill/kWh only achieves mercury control of approximately 60%.

Brayton Point testing

Brayton Point Station's Unit 1 is a tangentially fired boiler converted from oil to coal and rated at 245 MW. The flue gas stream divides into two sides and remains divided as it passes through the electrostatic precipitators (ESPs). Testing was performed only on the east side of the gas stream, thus representing approximately 122 MW. Unit 1 has two cold-side (i.e., after the air preheater) ESPs, in series, with the second being newer and larger than the first. Sorbents were injected into the east side of Unit 1 ductwork between the old and the new precipitators; therefore capture of sorbents was accomplished by the second precipitator. The unit burned West Virginia low-sulfur bituminous coal during the testing. The hopper ash from both precipitators is combined and processed by an on-site carbon separation system. The processed ash is sold as base for concrete and the remainder of the higher carbon ash is disposed of as waste. The unit has an EPRICON flue gas conditioning system that uses SO₃ for fly ash resistivity control.

The Parametric Tests consisted of a series of eight-hour tests conducted at different sorbent, feedrate and operating conditions and were performed at full load. The areas of interest included mercury removal as a function of injection rate, the effect of operational conditions with and without carbon injection on mercury removal, and performance of "alternative" sorbents to the baseline sorbent "Norit FGD." Results from screening tests done in February 2002 indicated that the presence of SO₃ in the flue gas from the EPRICON system decreased the adsorption capacity of a few candidate sorbents by a factor of at least 2. Five sorbents were chosen for the Parametric Tests based on the screening tests and various sorbent selection criteria. The sorbents and injection rates used during the parametric tests consisted of Norit Americas, Inc. FGD at 1, 3, 10, and 20 lb/MMacf, and Superior Adsorbents, Inc., CarboChem, Donau Carbon, and EPRI sorbents at 3 and 10 lb/MMacf. The parametric tests ended with tests of the Norit FGD sorbent at 10 and 20 lb/MMacf with the EPRICON system off and on.

Norit America's Inc. FGD was the sorbent used for the Long Term full-scale testing. The Long Term Test was a ten-day run at constant conditions using optimum sorbent and feedrate. Ontario Hydro testing was performed during two of these days in order to check the S-CEM analyzer values. The powdered activated carbon was to be injected at 10 lbs/MMacf, although if the carbon content of the ash was under acceptable limits, testing was to proceed at 20 lbs/MMacf with the carbon content in the ash being closely monitored.



The Brayton Point Parametric Test results indicate that the higher the concentration of sorbent injected, the more mercury removed. Removal values range from 0 – 50% at 3 lb/MMacf and 75 – 95% at the highest sorbent injection rate of 20 lb/MMacf.

Both the removal trend and the sorbent costs preliminary results indicate that Brayton Point does not exhibit a sorbent injection level at which further injection of sorbent provides no further mercury removal. Instead, addition of more sorbent results in additional mercury reductions over the range of sorbent injection levels tested, with an approximately linear trend. This result is different from that seen at the two other facilities at which ADA-ES has completed testing, in that the other facilities showed definitive injection rates above which increased sorbent injection achieved little additional mercury removal. ADA-ES believes Brayton Point was different from the other two sites at which testing has been completed in that:

- flue gas conditions presented measurement challenges for the S-CEMs,
- Brayton Point's two ESPs in series is an unusual configuration,
- Brayton Point's second ESP is larger than most, and
- documented variability in day to day performance.

The results of the Brayton Point Long Term Test are not yet fully analyzed, nor are the coal, ash and economic analyses complete.

Salem Harbor testing

Salem Harbor Station's Unit 1 is a single-wall-fired boiler rated at 88 MW. The flue gas stream divides into two sides and remains divided as it passes through the electrostatic precipitator (ESP). Testing will be performed only on one side of the gas stream, thus representing approximately 42 MW. The unit fires a low sulfur, bituminous coal and uses oil for startup. The particular characteristics of the unit that make it of interest are: use of a urea-based Selective Non-Catalytic Reduction (SNCR) system for NO_x control, high ash carbon content (i.e., LOI) of 25%, and a low ESP operating temperature of 255°F.

As indicated in the test protocol, the primary objective of the testing at Salem Harbor is to find out whether sorbent injection can enhance mercury removal beyond the baseline removal by flyash. The secondary objective is to better understand the cause of the existing high mercury removal baseline (initially discovered during EPA's 1999 Mercury Information Collection Request), to be accomplished by varying process conditions. Variables that may contribute to the high removals include low ESP operating temperatures, high ash carbon content, and the operation of the SNCR. A single sorbent will be injected, specifically Norit America's "Darco FGD." The native fly ash at Salem Harbor is viewed as a second sorbent, since this ash already is proven to have close to 90% removal. The testing at Salem Harbor was not complete at the writing of this report.

Summary of ADA-ES testing

ADA-ES's preliminary results based on testing at three facilities are:

- PAC injection can capture elemental and oxidized mercury from both bituminous and subbituminous coals,
- additional field tests and long-term demonstrations are necessary to continue to mature the technology,
- fabric filters provide better contact between the sorbent and mercury than ESPs resulting in higher removal levels at lower sorbent costs,
- coal characteristics appear to affect ACI performance with an ESP, and
- small amounts of carbon in fly ash can limit use as a cement admixture, potentially affecting overall costs.

ADA-ES has indicated that the final report on all four facilities will not be ready before summer 2003.



JURAT ATTACHMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

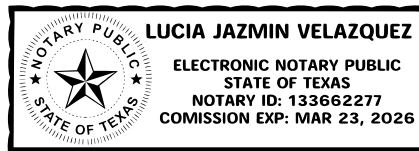
STATE OF Texas }

COUNTY OF Harris }

The foregoing instrument was subscribed and sworn before me this date of
01/13/2025 by Tanya Zeif

This notarial act was an online notarization.

(Notary Seal)



Notary's Signature Lucia Velazquez

Registration No.: 133662277

Document Notarized using a Live Audio-Video Connection

Commission Expiration Date: March 23, 2026

