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August 2, 2011

Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Air and Radiation Docket
Mail Code 2822T
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460
Attention: Docket ID Nos. EPA–HQ–OAR–2009–0234 (NESHAP) and EPA–HQ–OAR–2011–0044 (NSPS)

Re: *Proposed Rule – National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*

Dear Administrator Jackson:

The Northeast States for Coordinated Air Use Management (NESCAUM) offer the following comments on the U.S. Environmental Protection Agency's (EPA's) proposal, published on May 3, 2011 in the Federal Register, entitled "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units" (76 FR 24976-25147) (*hereinafter* "Utility MACT Rule"). NESCAUM is the regional association of air pollution control agencies representing Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

The proposed Utility MACT Rule reflects long standing requirements contained within the Clean Air Act that Congress adopted and charged EPA with the responsibility for implementing. While some have argued that the statutorily-required compliance timeline is too tight, power plant owners have been on notice of pending control requirements since late 2000 when EPA determined as part of a study required by the 1990 Clean Air Act Amendments that regulating mercury and other toxic air emissions from power plants was "appropriate and necessary."[1] The 2008 D.C. Circuit decision in *New Jersey v. EPA* (517 F.3d 574) vacating the earlier Clean Air Mercury Rule was another clear signal of the need to address hazardous air pollutants from power plants under § 112 of the Clean Air Act. As we describe later in these comments, a

[1] "Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units," 65 Fed. Reg. 79825 (December 20, 2000).

NESCAUM Members:
Connecticut Bureau of Air Management, Anne Gobin
Maine Bureau of Air Quality Control, Melanie Loyzim
Massachusetts Bureau of Waste Prevention, Nancy Seidman
New Hampshire Air Resources Division, Robert Scott
New Jersey Division of Air Quality, William O'Sullivan
New York Division of Air Resources, David Shaw
Rhode Island Office of Air Resources, Douglas McVay
Vermont Air Polution Control Division, Richard Valentinetti

number of the NESCAUM states (and elsewhere) have already adopted state mercury rules for coal-fired power plants, with controls in place at a growing number of units.[2]

As proposed, the Utility MACT Rule will have public health and environmental benefits that far exceed its projected costs. In the regulatory impact analysis for the proposed rule, EPA estimated monetized benefits associated with reductions in mercury and particulate matter (used as the surrogate for non-mercury toxic metals) in the range of $53-140 billion in 2016, with projected costs of $10.9 billion (2007$).[3] EPA did not quantify benefits for a number of health and welfare end points, such as those associated with reductions in non-mercury hazardous air pollutants. As a result, the monetized benefits are a lower bound of the potential benefits resulting from reductions of the full suite of air toxics under the proposed rule. Therefore, as we discuss further in our detailed comments, we urge EPA to move expeditiously to finalize these standards so that the public health and welfare benefits begin to accrue as soon as possible.

I. Previous NESCAUM Comments on Clean Air Mercury Rule (CAMR)

In commenting in 2004 on the proposed Clean Air Mercury Rule (CAMR), the vacated predecessor of the proposed Utility MACT rule, NESCAUM expressed four specific concerns: (1) EPA's maximum achievable control technology (MACT) floor determination was flawed; (2) EPA's proposed trading schemes under either Clean Air Act § 111 or § 112 were illegal and bad public health policy; (3) EPA needed to consider other hazardous air pollutants (HAPs) in the proposed regulation in addition to mercury; and (4) despite EPA's claims to the contrary at that time, control technologies were commercially available to substantially reduce mercury emissions from electric generating units (EGUs).[4]

NESCAUM is pleased to see that EPA's proposed Utility MACT Rule now seeks to address all four of these concerns in a more constructive manner that is better aligned with the statutory language of the Clean Air Act and sound public health policy. The NESCAUM states agree with EPA's December 2000 finding that regulating HAP emissions from EGUs under Clean Air Act § 112 is "appropriate and necessary," agree with EPA's current confirmation of the December 2000 finding, and agree with EPA that its subsequent reversal of this finding in 2005 was in error.

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[2] National Association of Clean Air Agencies (NACAA), "State/Local Mercury/Toxics Programs for Utilities," April 6, 2010, available at http://www.4cleanair.org/Documents/StateTableupdatedApril2010.doc (accessed January 18, 2011).

[3] U.S. EPA, *Regulatory Impact Analysis for proposed Toxics Rule (the Utility MACT and NSPS proposals)*, U.S. EPA, March 16, 2011. Available at http://www.epa.gov/ttn/ecas/ria.html (accessed March 16, 2011).

[4] NESCAUM comments to EPA on *Proposed National Emission Standards for Hazardous Air Pollutants; and in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units* (69 FR 4652-4752), submitted June 29, 2004 (available at http://www.nescaum.org/documents/proposed-national-emission-standards-for-hazardous-air-pollutants/).

II. Public Health Concerns

a. Mercury problem in Northeast

Mercury is a health and environmental issue for the NESCAUM states. Mercury deposition from upwind sources has significantly affected aquatic and terrestrial environments in the Northeast, resulting in states having to issue fish consumption advisories to protect human health.

Over 15,000 fish samples collected in the Northeast confirm widespread mercury contamination of our aquatic ecosystems, threatening human health and wildlife unless actions are taken to reduce significant local and upwind sources of mercury emissions. Mercury contamination threatens the tourist and recreational fishing industries, which contribute $3 billion a year to our regional economy. Pursuant to the federal Clean Water Act, all the NESCAUM states have established EPA-approved total maximum daily loads (TMDLs) for mercury entering the waters of the Northeast.[5]

Historically, the NESCAUM states have adopted more stringent mercury controls on air pollution sources, and in advance of national requirements. These have included limits on municipal waste combustors and medical waste incinerators. As described later in these comments, the NESCAUM states with coal-fired EGUs have already adopted state rules that limit mercury emissions from these power plants at levels that are comparable to, and in many cases more stringent than, the mercury limits in EPA's proposed mercury standards.[6]

In addition to air releases, the Northeast states have also implemented programs that reduce mercury releases to water and waste streams, such as use of dental amalgam separators and restrictions on the sale and disposal of mercury-added products (e.g., automotive light switches, thermometers, thermostats).[7] These efforts have had positive results. Reductions in mercury releases in the Northeast have been correlated with reductions in mercury concentrations in fish

[5] EPA Region 1 letter to CT DEP, *Notification of Approval of Northeast Mercury TMDL*, December 20, 2007; EPA Region 2 letter to NJ DEP, *Review of Total Maximum Daily Load (TMDL) for Mercury Impairments Caused Mainly by Air Deposition in 122 HUC 14s Statewide, New Jersey (NJ),* September 25, 2009.

[6] Connecticut General Statutes (CGS) section 22a-199; Massachusetts adopted rule 310 CMR 7.29; New Hampshire Revised Statutes Annotated (RSA) Chapter 125-O; New Jersey Statutes Annotated (NJSA) 7:27-27; New York Codes, Rules and Regulations (NYCRR) Part 246.

[7] King, S., P. Miller, T. Goldberg, J. Graham, S. Hochbrunn, A. Wienert, and M. Wilcox. 2008. Reducing Mercury in the Northeast United States. *EM*, Air & Waste Management Association (Pittsburgh, PA), pp. 9-13 (May 2008).

tissue in a number of Northeast water bodies[8,9] and in the effluent discharged from municipal wastewater treatment plants.[10]

Despite these successful measures, transported mercury emissions from out-of-region coal-fired EGUs are a major contributor to mercury deposition in the Northeast. Based on an EPA-sponsored modeling analysis,[11] NESCAUM concluded that much of the mercury entering the Northeast's aquatic ecosystems is deposited from the air, and a significant portion of this mercury comes from emission sources outside the NESCAUM region.[12] As part of a Clean Water Act sec. 319(g) conference that focused on water quality impairment issues identified in the Northeast Regional Mercury TMDL, EPA reviewed NESCAUM's analysis and found its results virtually identical with EPA's own analysis.[13]

In order for the northeast states to achieve their mercury TMDL targets, mercury deposited from the air may need to be reduced in the range of 87 to 98 percent.[14] In view of the public health and environmental impacts associated with exposure to mercury, and the contributions of long-range transport of mercury from sources outside the NESCAUM region, it is extremely important that the EPA take swift, aggressive, and comprehensive steps to reduce mercury emissions from EGUs and other air emission sources.

b. Non-mercury air toxics health concerns

The NESCAUM states are pleased to see that EPA's proposal now includes non-mercury air toxics, which were missing from the 2004 CAMR proposal. EGUs release many more air toxics than just mercury, and comprehensive protection of public health requires a wider net be cast to address the many different HAPs emitted by these sources.

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[8] Massachusetts Department of Environmental Protection (MassDEP). "Massachusetts fish tissue mercury studies: Long-term monitoring results, 1999-2004." MassDEP Office of Research and Standards, Boston, MA and Wall Experiment Station, Lawrence, MA (2006).

[9] Evers, D.C., Y.-J. Han, C.T. Driscoll, N.C. Kamman, M.W. Goodale, K.F. Lambert, T.M. Holsen, C.Y. Chen, T.A. Clair, and T. Butler. 2007. Biological mercury hotspots in the northeastern United States and southeastern Canada. *BioScience* 57: 29-43.

[10] King, S., P. Miller, T. Goldberg, J. Graham, S. Hochbrunn, A. Wienert, and M. Wilcox. 2008. Reducing Mercury in the Northeast United States. *EM*, Air & Waste Management Association (Pittsburgh, PA), pp. 9-13 (May 2008).

[11] U.S. EPA. "Model-based Analysis and Tracking of Airborne Mercury Emissions to Assist in Watershed Planning." Final Report, U.S. EPA Office of Wetlands, Oceans, and Watersheds, Washington, DC (August 2008), http://water.epa.gov/lawsregs/lawsguidance/cwa/tmdl/upload/final300report_10072008.pdf (accessed June 11, 2011).

[12] Northeast States for Coordinated Air Use Management (NESCAUM). "Sources of Mercury Deposition in the Northeast United States." NESCAUM, Boston, MA (March 2008), http://www.nescaum.org/documents/nescaum-sources-of-hg-depo-in-northeast_2008-final.pdf/.

[13] U.S. EPA. "Determination of Mercury Deposition Contributions from States Outside the Northeast." Presentation by Dwight Atkinson, U.S. EPA, at Clean Water Act Section 319(g) Mercury Conference, Philadelphia, PA, June 22-23, 2010.

[14] New England Interstate Water Pollution Control Commission (NEIWPCC). "Northeast Regional Mercury Total Maximum Daily Load." NEIWPCC, Lowell, MA (submitted to U.S. EPA on October 24, 2007; approved by U.S. EPA on December 20, 2007).

A suite of non-mercury toxic metals have attributes known to harm public health. For example, researchers have implicated nickel emissions from oil combustion with an increased risk in daily mortality.[15] In the Northeast, EGUs burning No. 6 residual oil are a large source of these emissions. EPA provides a good summary in its proposal of the cancer and non-cancer impacts for the non-mercury toxic metals, acid gases, and organic HAPs, including dioxins/furans. This is a compelling health basis for moving forward with standards and measures aimed at this broader set of HAPs.

III. Mercury

a. Proposed mercury MACT standard

We appreciate the transparency EPA has provided in making available the stack test data and explaining its variability methodology. We have reviewed this information, and as we will explain in more detail below in our comments on variability, we believe there is a sound basis to establish a MACT floor within a lower range than what EPA is proposing.

EPA initially proposed a mercury MACT limit of 1.0 pounds per trillion British thermal units fuel input (lb/TBtu) for existing coal-fired units designed for coal ≥ 8,300 Btu/lb, which it has now adjusted to 1.2 lb/TBtu due to identified earlier discrepancies in recalculating historical mercury emissions data.[16] Notwithstanding the previously cited data discrepancies, our review of the data set and the variability analysis used by EPA indicates that a realistic MACT floor for mercury emissions from these types of units should be recalculated taking our review of the data into account. We also note that some individual member states of NESCAUM will be submitting separate comments on their states' behalf with additional recommendations for mercury MACT limits based on their re-analysis of the EPA data set.

b. NESCAUM states have already successfully implemented mercury limits for coal power plants that are more stringent than EPA's proposed mercury standards

A number of NESCAUM states with large coal-fired power plants have already adopted stringent mercury control requirements for these facilities that are, in most cases, more stringent than those of EPA's proposed mercury standards. Some provisions of the states' rules have now been in effect for several years, and compliance data indicate that the affected units are achieving the required mercury reductions. This successful experience is a harbinger of the ability of coal units elsewhere to achieve significant mercury reductions with existing control technologies. Below are brief summaries of NESCAUM state rules and experience in controlling mercury from coal-fired EGUs. The accompanying Attachments A and B provide tables summarizing the state mercury rules and the controls installed or planned at coal power plants in the NESCAUM region to comply with the state rules.

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[15] Lippmann, M., K. Ito, J.S. Hwang, P. Maciejczyk, and L.C. Chen. 2006. Cardiovascular Effects of Nickel in Ambient Air. *Environ. Health Perspect.* 114(11): 1662-1669.

[16] Letter from U.S. EPA Assistant Administrator Gina McCarthy, Office of Air and Radiation, to Lee B. Zeugin, Hunton & Williams, Counsel to the Utility Air Regulatory Group, May 18, 2011.

Connecticut
Under Connecticut General Statute section 22a-199, adopted in 2003, coal-fired EGUs in Connecticut had to achieve by July 1, 2008 a mercury emissions limit of 0.6 lbs/TBtu or a rate equivalent to a 90 percent reduction from measured inlet conditions.

Of the three affected Connecticut units, the Bridgeport unit installed activated carbon injection (ACI) with a pulse-jet fabric filter baghouse to achieve mercury reductions. The AES Thames units are circulating fluidized bed boilers with dry limestone injection and fabric filtration to control sulfur, and were able to meet the state limits without installing mercury-specific controls.

Quarterly stack testing of the three affected units in Connecticut (PSEG Bridgeport Harbor unit 3, AES Thames units 1 and 2) indicated that they achieved the state's mercury requirements.[17]

Massachusetts
In 2001, as part of a multi-pollutant regulation controlling sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury, Massachusetts established annual mercury emission caps for the state's coal-fired power plants at the then-current level of emissions. To reduce emissions, in 2004, Massachusetts revised its state rule (310 CMR 7.29) to require specific mercury emission limits at the state's coal-fired EGUs in two phases. Phase 1 required a minimum 85 percent mercury capture as compared to 2001-2002 inlet emissions or a maximum emission rate of 0.0075 lb/GWh by January 1, 2008, and required continuous monitoring of mercury emissions by the same date. Phase 2 requires a minimum of 95 percent mercury capture as compared to 2001-2002 inlet emissions or a maximum emission rate of 0.0025 lb/GWh by October 1, 2012. The rule allows averaging between units at the same power plant.

Of the eight EGUs subject to Phase 1 of Massachusetts' rule, one unit (Somerset) has shut down, three units (Salem Harbor) did not need to install mercury controls because they could meet the Phase 1 standard without additional controls and have announced they will shut down, and one unit (Mt. Tom) installed selective catalytic reduction (SCR), a dry scrubber (DS) and a fabric filter. At Brayton Point, unit 1 installed SCR, dry sorbent injection (DSI), spray dryer absorption (SDA), and a fabric filter (FF), unit 2 installed DSI-SDA-FF, and unit 3 installed SCR and has DSI-DS-FF under construction.

The affected units have continuous emission monitoring systems (CEMS) or sorbent trap data to determine compliance with the state's regulation. The compliance reports submitted in January 2011 show mercury compliance for 2010 at all operating units.

[17] AES Thames units 1 and 2 have been shut down since January 2011, but were in compliance when operating.

New Hampshire
New Hampshire has adopted state legislation (RSA 125-O:11-18) calling for a state-wide 80 percent reduction in coal-fired power plant mercury emissions through installation of wet flue gas desulfurization technology ("wet scrubber") at the Public Service of New Hampshire Merrimack Station no later than July 1, 2013. A power plant can earn sulfur dioxide emission credits for early mercury reductions prior to the 2013 deadline. The state law applies to Merrimack units 1 and 2 and Schiller units 4, 5, and 6. It does not allow the purchase of mercury credits or allowances to meet compliance, nor does it allow the sale of credits or allowances generated through mercury reductions at a unit as a result of the state's law.

New Jersey
New Jersey's 2004 state rule (N.J.A.C. 7:27-27.1 *et seq.*) requires coal-fired units of any size in the state to achieve a mercury control efficiency of 90 percent or a mercury emission limit of 3.00 mg/MWh by December 15, 2007. New Jersey also provides for a multi-pollutant approach to reduce nitrogen oxides, sulfur dioxide, and fine particulates that can extend a unit's mercury compliance deadline to December 15, 2012 if approximately 50 percent of a company's coal-fired capacity in the state meets the mercury limits by the 2007 deadline.

Ten units were covered by New Jersey's mercury rule at the time it was adopted in 2004. Coal units are using ACI to meet the rule requirements, and stack testing indicates the applicable limits are being met.

New York
In January 2007, New York enacted a rule (6 NYCRR Part 246) for the control of mercury emissions from coal-fired EGUs that incorporates a Phase I facility-wide emission cap in the years 2010-2014 and establishes a unit-based emission limit for each applicable unit beginning in 2015. The facility-wide cap does not allow affected power plants to generate and trade mercury reductions with other facilities in-state or out-of-state. Phase I of the rule imposes annual facility-wide mercury emission limitations, based upon the state mercury budget EPA distributed to New York under the vacated Clean Air Mercury Rule. The annual facility-wide emission limitations will be in effect from 2010 to 2014. Starting in 2015, in conjunction with other electric sector regulations such as the Regional Greenhouse Gas Initiative (RGGI) and EPA's previously enacted Clean Air Interstate Rule, now re-promulgated as the Cross-State Air Pollution Rule, state mercury regulation will establish a facility-wide mercury emission limit of 0.6 lb/TBtu.

Compliance with the state's Phase I limits have been met with sulfur reduction technologies that have co-benefits in reducing mercury. These include the following; 1) the installation of SCR-FF on three EGUs; 2) previously installed SDA-FF at five EGUs prior to the regulation effective date of January 31, 2007; and 3) electrostatic precipitators (ESPs) at two EGUs. No facilities are yet using ACI until they need to meet the more stringent 0.6 lb/TBtu mercury limit in 2015 on a daily average. Electric generating units with nitrogen oxides and sulfur dioxide control in New York are achieving mercury emission rates in the 0.6 lb/TBtu range and will use ACI to achieve

consistent emission levels. Currently, all operating coal-fired EGUs in New York State are meeting the Phase I facility-wide caps.

c. Mercury control options are commercially available and demonstrated to work

As is evident from the experience in the NESCAUM states, there are a number of technology approaches available to meet mercury reduction requirements for coal-fired power plants. Because the NESCAUM states took early action, they have established an operational track record demonstrating the ability of these technologies to meet the mercury standards in EPA's proposed rule.

Based on a recent assessment of power plant control technologies prepared for NESCAUM, about 25 units representing approximately 7,500 MW are presently using commercial ACI technologies for mercury control.[18] (The NESCAUM assessment is included as part of these comments). In addition, as of June 2010, about 55,000 MW of new ACI bookings are reported by the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources.[19]

In addition, as seen by state experience in the NESCAUM region, mercury can be captured to some degree by existing air pollution controls, and, in many cases, technologies to control one pollutant have the co-benefit of also controlling other pollutants. For example, scrubbers, which are designed to control sulfur dioxide, are also reducing emissions of mercury (as well as particulate matter, other toxic metals, and acid gases).

In NESCAUM's assessment of power plant control technologies, we identified a number of control options that directly targeted mercury for control or had the co-benefit of reducing mercury when targeting other air pollutants. Activated carbon injection can be installed to directly target mercury, while the following options reduce mercury as a co-benefit: combustion controls, selective catalytic reduction, electrostatic precipitators, baghouses, dry and wet scrubbers, and dry sorbent injection.

d. Subcategories of coal types based on calorific content

The NESCAUM states agree with previous testimony provided to EPA at the May 24 Chicago hearing by the National Association of Clean Air Agencies (NACAA) that there is weak support for a separate subcategory called "coal-fired units designed to combust coal with a heat content less than 8300 Btu/lb." As the NACAA testimony indicated, "there are 30 sources within this proposed subcategory and slightly over 1061 units in the large category of coal-fired units (for mercury). The rationale put forward in the proposal for establishing the proposed mercury

[18] J. Staudt (Andover Technology Partners) and M.J. Bradley & Associates. "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants." Report prepared for NESCAUM, Boston, MA (March 31, 2011), http://www.nescaum.org/documents/coal-control-technology-nescaum-report-20110330.pdf/.

[19] Institute of Clean Air Companies (ICAC). "Commercial Bookings List." June 2010, http://www.icac.com/files/members/Commercial_Hg_Bookings_060410.pdf (accessed February 1, 2011).

subcategory is that no unit meeting this definition was within the top 12 percent of performing sources in the larger category. Even if it were permissible to establish subcategories based on emission test results, absent an engineering basis for doing so, the EPA test data does not appear to support a separate subcategory in this instance."[20]

IV. Non-mercury Metal HAPs

a. Proposed non-mercury metal HAPs MACT standards

The NESCAUM states support the proposed MACT standards for non-mercury metal HAPs, with the caveat that EPA should follow conventional rounding rules to establish the standards. For present purposes, the NESCAUM states also support using total particulate matter (PM) as the surrogate for non-mercury metal HAP emissions. This is based on the premise that most if not all non-mercury HAP metals are entrained in the flue gas fly-ash such that effective PM controls will also effectively capture the non-mercury metal HAP constituents within the total PM. We recognize, however, that smaller size particulate matter (e.g., $PM_{2.5}$) may be a better indicator due to preferential partitioning of non-mercury metal HAPs in the smaller size fractions of total PM. As EPA indicates, test methods for $PM_{2.5}$ in flue-gas are not applicable to all exhaust stack conditions. For the future, we encourage EPA to develop more broadly applicable $PM_{2.5}$ stack test methods that can replace total PM as the non-mercury metal HAP surrogate, to the extent feasible.

b. Non-mercury metal HAPs control options are commercially available and demonstrated to work

As described in the accompanying control technology assessment, there are readily available control technologies for reducing total PM; hence, non-mercury metal HAPs, emitted by coal-fired EGUs. These technologies include electrostatic precipitators and baghouses (fabric filters). The electric power sector has an established history in installing and operating these types of controls. For example, more than 300 existing coal-fired power plants are reported to have installed ESPs and/or baghouses.[21]

V. Acid Gas HAPs

a. Proposed acid gas HAP MACT standards

The NESCAUM states support proposed acid gas HAP MACT standards that have the potential of reducing acid gas emissions from EGUs by over 90 percent, with the caveat that EPA should

[20] National Association of Clean Air Agencies (NACAA), Testimony presented by David Shaw, NACAA Co-President and Director of the New York Division of Air Resources, at the EPA hearing on *Proposals for National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units*, Chicago, IL (May 24, 2011).

[21] Environmental Health and Engineering, Inc. "Emissions of Hazardous Air Pollutants from Coal-fired Power Plants." Needham, MA (March 7, 2011), http://www.lungusa.org/assets/documents/healthy-air/coal-fired-plant-hazards.pdf, Table 6 (accessed May 18, 2011).

follow conventional rounding rules to establish the standards. The NESCAUM states also support using hydrogen chloride (HCl) as the surrogate indicator for acid gas HAPs in a technology-based MACT standard.

With regard to using sulfur dioxide (SO_2) as the alternative equivalent acid gas surrogate to HCl for units with SO_2 scrubbers, the NESCAUM states provide qualified support to the extent it is clear that the projected SO_2 reductions associated with meeting the acid gas HAP MACT limit are not, by extension, considered an adequate level of control for SO_2 under all settings. The NESCAUM states recognize that because SO_2 is a criteria air pollutant, and not a HAP, the use of SO_2 as an alternative surrogate under Clean Air Act § 112 is solely for purposes of regulating HAPs and not for direct regulation of SO_2 *per se*. Greater reductions in SO_2 emissions are achievable with existing technologies than EPA assumes would occur to achieve a greater than 90 percent reduction in acid gas HAP emissions. Additional SO_2 reductions from EGUs may be necessary, for example, to achieve SO_2 and $PM_{2.5}$ national ambient air quality standards. Therefore, the SO_2 reductions occurring as a result of its use as an alternative surrogate for acid gas HAP MACT standards should not be considered an indicator of maximum achievable SO_2 reductions from EGUs for purposes of meeting national ambient air quality standards.

b. Acid gas HAPs control options are commercially available and demonstrated to work

For EGUs with wet or dry scrubbers for SO_2 control (installed at about 200 U.S. coal power plants),[22] these controls will likely provide the co-benefit of HCl capture for meeting the proposed acid gas MACT standard. For those units that are unscrubbed, other technology options exist in addition to scrubbers. For example, unscrubbed EGUs could be retrofit with dry sorbent injection (DSI) systems and fabric filters that are relatively inexpensive in capital cost, especially for smaller EGUs (< 250 MW). They can also be simpler to install compared to scrubbers, with typical installation times within 12 months. While DSI units have been demonstrated to achieve HCl capture rates well above 90 percent, SO_2 removal is typically more modest compared to scrubber technologies (see attached NESCAUM report on control technologies for coal-fired power plants). DSI controls have not been as widely installed as other EGU control technology options, but there are a growing number of power plants with installed DSI and operating experience that demonstrate DSI's ability to significantly reduce acid gas HAP emissions.[23]

VI. Work Practice Standards for Organic HAPs, Including Dioxins and Furans

The NESCAUM states agree that work practice standards are appropriate for addressing organic HAPs, including dioxins and furans, in lieu of numerical MACT standards. Concentrations of these HAPs in EGU stack flue-gases are often below instrumental minimum detection limits,

[22] Environmental Health and Engineering, Inc., Table 6.
[23] Kong, Y. and M. Wood. 2011. Dry Injection of Sodium Sorbents for Air Pollution Control. *Environ. Engineer* 47: 20-23.

making determinations of organic HAP emission rates infeasible using standard detection methods.

VII. EGUs Not Subject to Subpart UUUUU (76 FR 25102)

The NESCAUM states support EPA's proposed EGU exemptions as listed in paragraphs (a) through (c) of section 63.9983.

VIII. Additional Comments

a. Variability Analysis

The NESCAUM states commend EPA for making available the necessary documents on its Technology Transfer Network (TTN) webpage in addition to the docket location. With the use of these data, EPA offered transparency for all interested parties to understand the MACT floor process. In the document entitled "Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units," EPA describes the statistical techniques used to develop the MACT floor for each subcategory. In another document on the TTN webpage, EPA supplied a spreadsheet MACT floor analysis for all the stated subcategories, including a separate tab for sources that use ACI in conjunction with other conventional pollution control devices.

As explained in EPA's MACT floor analysis, the need to incorporate variability into the calculations of the applicable MACT floor limits for each of the subcategories is important. EPA's approach is to use "the data's 99 percent upper prediction limit (UPL). Specifically, the MACT floor limit is an UPL calculated with the Student's t-test using the 'TINV' function in Microsoft Excel software. The Student's t-test has also been used in other EPA rulemakings (e.g., NESHAP for Portland Cement, NSPS for Hospital/Medical/Infectious Waste Incinerators, NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters) in accounting for variability and reflects the level of confidence."[24]

In August 2010 comments submitted by NACAA on proposed MACT standards for industrial, commercial, and institutional boilers, process heaters, and solid waste incinerators, NACAA reviewed EPA's statistical process for assessing unit to unit variability in the context of establishing a MACT floor level. The NACAA comments pointed out that care must be taken with "data that reflect emissions variability when emissions are unconstrained[.] … For this reason any calculation of variability using pre-regulation testing will likely overstate the post-regulation variability to some degree." NACAA noted that the upper 99th prediction limit is "actually developing a reasonable compliance margin to apply to the best-complying sources, rather than anything to do with the calculation of the effect of individual unit variability on the

[24] U.S. EPA. "National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units – REVISED" May 18, 2011 at http://www.epa.gov/ttn/atw/utility/pro/egu_revised_mact_floor_memo_051811_final.pdf.

average of the top performing 12 percent of units in a subcategory."[25] It is our understanding that EPA is effectively developing a compliance margin for post-regulation sources, therefore we wish to emphasize in our comments that the appropriate sources and performance tests should be represented in EPA's variability approach. Some pre-regulation sources included in EPA's analysis may not realistically reflect expected variability of post-regulation sources, so a revised variability analysis should be done that removes these.

As stated in EPA's MACT floor analysis;

> The level of confidence represents the level of protection afforded to facilities whose emissions are in line with the best performers, and consequently, the level of confidence is not arbitrary. For example, a 99 percent level of confidence means that a facility whose emissions are in line with the best performers has one chance in 100 of exceeding the floor limit. A prediction interval for a single future observation (or an average of several test observations) is an interval that will, with a specified degree of confidence, contain the next (or the average of some other pre-specified number) of randomly selected observation(s) from a population. In other words, the UPL estimates what the upper bound of future values will be, based upon present or past background samples taken.

While we agree that some reasonable compliance margin is appropriate for establishing MACT floors, that margin must appropriately encompass only those units that are truly "best performers." We have concerns with EPA's mercury MACT analysis in this proposal after finding upon review of the test data that 4 performance tests out of 80 are driving a significant portion of the "variability" (*see* Figure 1). Therefore, we request that EPA review and reconsider whether these sources are appropriate for inclusion in an analysis of expected variability by post-regulated sources.

EPA's MACT floor analysis for the subcategory "Existing Sources ≥ 8,300 Btu/lb" is based upon the average of the cleanest performance test at each of 40 facilities and the variability of their top 80 performance tests. Some facilities represent 1 performance test and others represent as many as 8 performance tests. Of the 80 tests, 76 are within a tight range of variability, having a mean of 0.12 lb/TBtu with an upper and lower 95 percent confidence interval of 0.16 and 0.084 respectively. In the approach used by EPA, an effort was made to establish a 99 percent upper prediction limit using a pooled variance analysis, so as to encompass the remaining 4 tests. The remaining 4 performance test values are 3.0, 2.4, 1.6 and 1.1 lb/TBtu, and are plotted in Figure 1. EPA should examine these sources to determine why their performance tests represent a 10 to 30 fold difference compared to the mean of the majority of other tests.

[25] NACAA (National Association of Clean Air Agencies) comments on EPA Proposals for Regulation of Hazardous Air Pollutants (HAPs) from Industrial, Commercial and Institutional (ICI) Boilers under Section 112 of the Clean Air Act (CAA) and for Regulation of Toxic and Criteria Air Pollutants from Commercial Industrial Solid Waste Incineration (CISWI) Units under Section 129 of the CAA, EPA Docket ID Nos. EPA-HQ-OAR-2006-0790; EPA-HQ-OAR-2002-0058; EPA-HQ-OAR-2003-0119 (August 23, 2010).

Of the eight performance tests presented in EPA's spreadsheet for BL England unit 2, the highest test performance was 2.4 lb/TBtu, with the highest of the remaining 8 quarterly tests from BL England having a maximum of 0.77 lb/TBtu. We cannot, however, reconcile the highest test result as given in the EPA spreadsheet with our review of this facility's reported mercury test results on file with NJ DEP during the period of 2008 and 2009 (included in Attachment C),[26] and request EPA review these test results.[27] Of the other three units, all have flue gas desulfurization (FGD) and a fabric filter, but none have activated carbon injection for mercury control. These three units are identified as 1) Spruance unit Gen4, which had 2 performance tests 0.012 and 1.6 lb/TBtu; 2) Scrubgrass unit Gen1 with 3 performance tests of 0.035, 0.56 and 3.0 lb/TBtu; and 3) Cherokee unit 4 with 3 performance tests of 0.032, 0.19, and 1.1 lb/TBtu. The inclusion of these units' anomalously high data points in EPA's variability analysis is the primary driver of the variability spread, introducing a greater margin of variability than one might expect from units that will be required to control for mercury. Without these 4 tests and using EPA's variability approach, the proposed mercury MACT limit is reduced from 1.2 lb/TBtu to 0.44 lb/TBtu.

MACT Floor Determination with Activated Carbon Injection

Another approach EPA could take would be to determine the MACT floor for existing facilities that use ACI or chemically treated ACI in conjunction with other pollution control devices, as these could reasonably be viewed as the variability to be expected among "complying units." Activated carbon has been demonstrated to consistently reduce mercury emissions, and EPA has conducted a MACT floor determination using the 45 units reporting ACI usage. The six units representing the top 12 percent were identified and these six units had a total of 21 performance tests among them. As with the MACT floor analysis for all units, BL England had 8 performance tests with 1 test at 2.4 lb/TBtu that we cannot reconcile with test results on file with the NJ DEP. The UPL determined in the worksheet made available by EPA established a MACT floor level of 1.5 lb/TBtu to accommodate this elevated value. The other 20 tests ranged from 0.0065 to 0.78 lb/TBtu. Substituting the BL England test of 2.4 lbs/TBtu with the maximum value otherwise reported (0.78 lb/TBtu) results in a MACT floor for ACI sources of 0.79 lb/TBtu using the pooled variance statistical calculation accounting for a 99 percent UPL.

[26] Communication from Sunila Agrawal, Supervising Environmental Engineer, New Jersey Department of Environmental Protection, Division of Air Quality, Trenton, NJ (June 15, 2011).

[27] The highest test report on file with NJ DEP during 2008-2009 was the Sept-Oct 2008 test report, which had reported mercury emission rates in test runs 1, 2 and 3 of 0.653, 0.534 and 0.465 µg/dscm, respectively. Runs 1, 2, and 3 had O_2 values of 9.5%, 9.4%, and 9.7%, respectively. Using these values in the formula Hg lb/mmBtu = Hg µg/dscm *0.02832 dscm/dscf * 9780 dscf/mmBtu (f-factor) * 20.9/((20.9-actual O_2%) * 10^6 * 453.6 g/lb), the average mercury emission rate of the three BL England tests would be 0.62 lb/TBtu, while EPA is reporting a value of 2.4 lb/TBtu, 3.9 times higher.

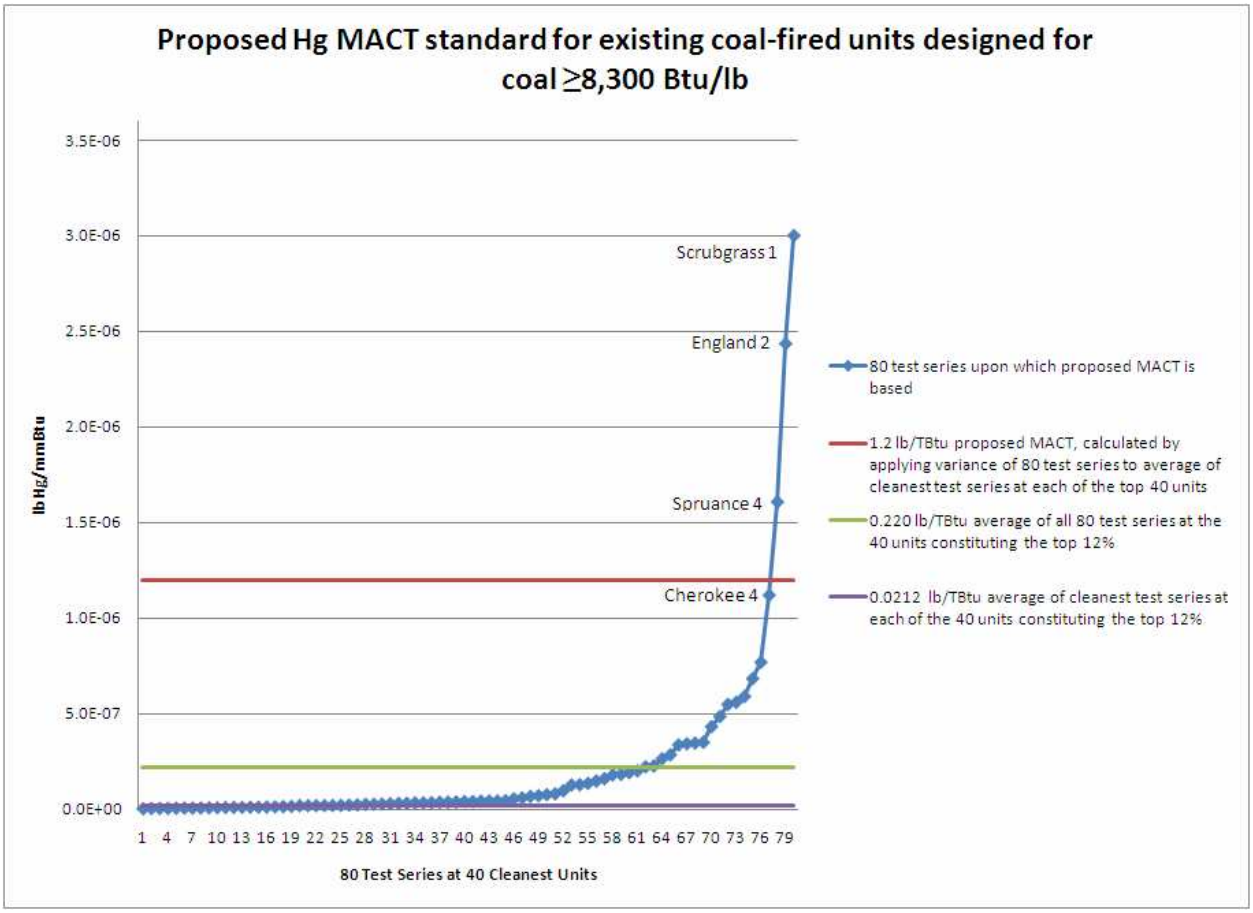

Figure 1. Plot of 80 test series for 40 units used in EPA mercury MACT analysis.

In summary, based on our review of the performance test data of the top performing 12 percent of units used by EPA and on consideration of what could be viewed as expected variability among "complying units," the NESCAUM states request EPA review the calculations to reflect these considerations.

b. National Electric Energy Data System (NEEDS)

States have previously submitted data updates to EPA for the NEEDS database in response to a Notice of Data Availability (NODA) for the proposed Transport Rule (75 FR 53613-53615). These state-supplied updates, however, do not appear to have been incorporated into this rulemaking.[28] The NESCAUM states would like to work with the appropriate EPA staff to ensure that inclusion of submitted state data reflecting the most current information on emission sources are incorporated into the NEEDS database on a more expedited basis.

[28] *See, e.g.*, Comments submitted by the New Hampshire Department of Environmental Services to EPA Docket ID No. EPA-HQ-OAR-2009-0491, *Notice of Data Availability Supporting Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone* (a.k.a. NODA for the Proposed Transport Rule) [75 FR 53613-53615], submitted October 15, 2010.

c. EGU gross vs. net output basis for MACT and NSPS standards

The EPA is proposing pollutant mass per gross output (MWh or GWh) emission limits for hazardous air pollutants emitted by new EGUs, and as an alternate format for existing EGUs (76 FR 25038). The EPA also asks for comment on proposed changes to the current gross output-based PM, SO_2, and NOx NSPS for EGUs that includes establishing potential net output-based standards for new and reconstructed EGUs (76 FR 25070).

1. Experience with output-based standards

The NESCAUM states have long considered the use of output-based standards to promote greater efficiency in the generation of electric power regardless of plant age or historical fuel use. In 1999, a NESCAUM state workgroup developed a model rule and supporting documentation for the application of output-based NOx, SO_2, and CO_2 emission performance standards to electricity retail suppliers in the Northeast.[29]

Two states in the NESCAUM region (Massachusetts and New Jersey) have extensive practical experience in implementing net output-based NOx and mercury emission limits for existing fossil fuel EGUs. We note that EPA states in its NSPS proposal that gross output-based standards provide facilities less encouragement than net output-based standards to be as efficient as possible in their on-site operations, including optimizing the efficiency of all equipment involved in electricity production.[30] Beginning in the early 2000s, the Massachusetts Department of Environmental Protection (MassDEP) required large power plants to specify methods of measuring net output in monitoring plans submitted under a NOx cap-and-trade program because its ozone season NOx trading program bases allocations on net MWh. These required monitoring plans include facilities that produce steam (either combined heat and power or steam-only plants), thus accounting for facilities that do not necessarily report their entire output as electricity. Separately, MassDEP has a regulation that affects large older power plants, requiring compliance with lb/net MWh output limits. The regulation requires, "A statement certifying that the MWhs of net electrical output used in compliance calculations reflect the total actual electrical output of the facility used by the New England Independent System Operator to determine settlement resources of energy market participants." The experiences of Massachusetts and New Jersey indicate that valid compliance methods can be (and have been) established for net output-based standards.

2. Net output-based NSPS standards

EPA states, "Because we do not have continuous net output data available, we are considering assuming 5 percent parasitic losses to convert the gross output values to net output. We are requesting comments on the appropriate conversion factor" (76 FR 25071). The NESCAUM

[29] Northeast States for Coordinated Air Use Management. "Emission Performance Standards: Model Rule Background Information Document," NESCAUM, Boston, MA, 1999.

[30] "To recognize the environmental benefit of overall environmental performance, we are considering establishing a net output-based emission standards [*sic*] for new and reconstructed units in the final rule in lieu of gross output-based standards." 76 FR 25070.

states are not in favor of using a single conversion factor to convert gross to net output-based NSPS standards. While the experiences in some NESCAUM states have been positive with net output-based standards, such an approach should only be pursued where the gains can be shown to be reliable and properly enforced, such as described in the MassDEP example in the above comment. EPA has resources it can use to convert the gross monthly NSPS emissions analysis used to develop the proposed NSPS gross output-based standards to net output-based standards. In particular, large power plants report monthly net output to the Department of Energy's Energy Information Administration (EIA) on EIA Form 923.[31] EPA has already linked the net output reported to EIA to the emissions reported to EPA under the federal Acid Rain Program and CAIR, in EPA's eGRID database.[32] EPA should use these resources to accurately determine net output-based NSPS standards, rather than applying a generic approach to convert gross to net standards.

3. Accuracy

The electrical grid operator in New England, ISO New England, has established calibration procedures, frequency and accuracy requirements for electric meters used to report electricity fed into the electric grid.[33] Facilities apply these calibration procedures to meters that variously measure gross or net output, depending on the choices made when the facility was built or modified over the years, as a matter of happenstance and contract provisions. Almost all new power plants report net output to the grid operator, and therefore calibrate and maintain net output meters (and typically also have gross meters, although the gross output is not reported to the grid operator). Some older power plants provide gross output levels to the electric grid operator, and separately buy their station service from the electric grid, and therefore calibrate and maintain gross output meters. EPA has not specified any calibration procedure, frequency or accuracy level required of electrical meters. It appears that EPA is presuming that gross electric meters are used for billing, allowing other parties to specify calibration procedures. In EPA's initial work on the use of power plant output data,[34] EPA rightly treated "[O]utput measurement equipment used as a billing meter in commercial transactions" as not needing further quality assurance or quality control (QA/QC) because there are two parties in a billing transaction with financial interest in accurate data. Unfortunately, in proposing gross output-based MACT and

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[31] EIA Form 923 data are available at http://www.eia.gov/cneaf/electricity/page/eia906_920.html.

[32] S*ee* http://www.epa.gov/cleanenergy/energyresources/egrid/.

[33] ISO New England, Operating Procedure 18 Metering and Telemetering Criteria, at http://www.isone.com/rules_proceds/operating/isone/op18/index.html.

[34] U.S. EPA. "Developing and Updating Output-Based NOx Allowance Allocations: Guidance for States Joining the NOx Budget Trading Program under the NOx SIP Call," U.S. EPA, May 8, 2000 at http://www.epa.gov/airmarkets/progsregs/nox/docs/finaloutputguidanc.pdf. "In the case where billing meters are used to determine output, you do not need to require QA/QC activities beyond what the company already performs," (page 155); "Any output measurement equipment used as a billing meter in commercial transactions does not require certification or testing requirements. To qualify as a billing meter, the measurement device must be used to measure electric or thermal output for commercial billing under a contract. The facility where the measurement device is located must have different owners from the owners of the party purchasing the electric or thermal output. The billing meter must record the hourly electric or thermal output. Any electric or thermal output values that the facility reports must be the same as the values used in billing for the output," (page 156).

NSPS standards and not proposing calibration procedures, EPA seems to have assumed that gross output meters are universally used in billing transactions, when, as discussed above, some power plants use net output meters as their billing meters. It is inappropriate to base MACT and NSPS compliance determinations for large power plants (some of the highest emitting sources in the country) on non-billing meters that are not calibrated following a specified procedure, frequency, and accuracy level.

4. Implementation

EPA currently requires reporting of hourly gross output to the Emissions Collection and Monitoring Plan System (ECMPS) for purposes of determining load for missing data procedures. Because EPA will need to amend the reporting requirements under 40 CFR Part 75 to incorporate reporting of MACT data, EPA should require MACT facilities that currently report gross output or steam load to switch to net output. Under 40 CFR 75.53(g)(1)(vii)(F), units are already required to report "when the maximum hourly gross load, boundaries of the range of operation, ...change and are updated" and to modify their data collection accordingly; this same process would apply to switching to reporting net output.

Based on experience in Massachusetts, most facilities' and units' determination of net output is straightforward, but there is a small subset of facilities that face facility-specific issues complicating determination of net output. For facilities with multiple units, only some of which are subject to MACT or NSPS, or for cogeneration or complicated situations, the standard 40 CFR Part 75 monitoring petition process could be used to work through complex situations. Certainly, new units should be required to use net output, because they can easily design and install systems to report net output.

d. <u>"Limited amount of time" definition for limited use subcategory (76 FR 25027)</u>

The limited use subcategory described at 76 FR 25027 does not include a definition as to what constitutes a "limited amount of time." The ability of sources to operate under a limited use subcategory could significantly affect compliance costs and requirements associated with the proposed Utility MACT Rule. EPA needs to provide more details on the limited use subcategory and in particular include a definition that will be used consistently by affected facilities.

e. <u>Proposal for one-year MACT extension for construction of on-site replacement power (76 FR 25055)</u>

The NESCAUM states agree that states should be able to consider on-site replacement power of an existing unit with another cleaner unit as "installation of controls" eligible for a one-year extension of the MACT compliance deadline. Granting of such an extension, however, should be limited to situations where the extra time is truly needed for installation of a cleaner unit, and not simply applied as a *pro forma* extension of the lifetime of an existing unit by one year when the cleaner replacement unit could have been installed within the three-year compliance period.

EPA cites combined cycle and simple cycle gas turbines as examples of cleaner units that states could consider for one-year extensions. In addition to these examples, we note that there may be

site-specific opportunities to install natural gas combined heat and power (CHP) and waste heat recovery (WHR) systems that can improve energy efficiency at a unit where a nearby serviceable load exists. As these types of systems may also require extra time to install, they too could be considered as "installation of controls" and eligible for consideration for a one-year extension period, if needed.

f. Energy Efficiency Scenario (76 FR 25073)

The NESCAUM states congratulate EPA for developing an Energy Efficiency Scenario that illustrates how the costs of the proposed Utility MACT Rule can be lowered through energy efficiency investments in lieu of retrofitting pollution controls or building new generation. Energy efficiency measures also enhance electric system reliability as reduced demand provides added space for retirement of generating units that are no longer needed. The retired units are likely to be the oldest, least efficient, and least technologically advanced generators, thus their final descent into obsolescence portends a more modern and reliable electric system. A number of northeastern states are already pursuing aggressive programs and directing investments for energy efficiency, with demonstrated results in reduced electricity demand and increased consumer savings.[35] There is great untapped potential in states that have not actively pursued these approaches, which represents a deep reservoir of lower cost opportunities to achieve the requirements of the proposed Utility MACT Rule.

g. Support fuel-based instead of stack-based testing for liquid oil-fired units; language clarification for sections 63.10006(o), (p), and (s) (76 FR 25107)

The NESCAUM states support fuel-based testing for compliance demonstrations by liquid oil-fired units, but not stack testing every other month. We do not believe stack testing every two months is EPA's intent, rather the language at 76 FR 25107 (sections 63.10006(o), (p) and (s)) needs to be clarified. It is not clear that the language at 76 FR 25107 (section 63.10006(p)) applies to low emitting EGUs, and it is difficult to understand how the timing set out in section 63.10006(o) follows in section 63.10006(p). Perhaps 63.10006(f) and (g) should refer to Table 6 (Fuel Analysis Requirements), not 5 (Performance Stack Testing Requirements), which would have more clearly allowed liquid oil-fired units to use fuel analysis to demonstrate compliance. In section 63.10006(s), the opportunity to demonstrate compliance with the mercury, individual or total non-mercury HAP metals, HCl, or HF emissions limit based on fuel analysis seems broader than the liquid oil-fired limited use subcategory, but the description in the preamble (see (d) above) appears to limit the fuel analysis compliance option to liquid oil-fired units that operate a limited amount of time per year on oil and are inoperative the remainder of the year.

Under section §63.10006 "When must I conduct subsequent performance tests, fuel analysis or tune-ups?," it is clear that affected EGUs firing solid oil-derived fuel and coal-fired must demonstrate continuous compliance with either CEMS, or stack testing based upon the

[35] Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.). "Investment of Proceeds from RGGI CO_2 Allowances." RGGI, Inc. (February 2011), at http://www.rggi.org/docs/Investment_of_RGGI_Allowance_Proceeds.pdf (accessed July 8, 2011).

methodologies in Table 5, stack testing. It is not clear in this section what is required for liquid oil-fired EGUs. In subdivisions (f) and (g), based upon EGUs with or without non-mercury HAP metal controls, continuous compliance is demonstrated by either every other month or monthly, respectively, performance testing (stack testing) based upon Table 5. In the same section §63.10006 subdivision (s), continuous compliance can be based upon fuel analysis, which contradicts subdivisions (f) and (g). The general requirements state fuel analysis is acceptable for liquid oil-fired EGUs for the initial and continuous compliance options. The continuous monitoring requirements for liquid oil-fired EGU should be rewritten for parity and clarity.

h. State resource burdens for stack testing requirements

Workload in observing emission tests and/or reviewing emission test protocols associated with the proposed Utility MACT Rule could greatly increase while states will likely be unable to add staff to meet this new workload. Requiring sources to conduct extensive testing without states being able to adequately monitor the testing is ineffective. NESCAUM suggests that once the initial performance test is conducted for PM (filterable and condensable) and non-HAP metals, and fuel sampling and/or operating parameters are established, fuel sampling would be a simpler approach then requiring excessive stack testing. The burden will move to the source owner without state and local staff being available to witness the numerous performance tests required. Another approach would be for EPA to consider revising the monthly and bimonthly testing requirements in Section 63.10006 for coal and solid oil-derived fuel to quarterly or biannual testing requirements in order to provide a reasonable window of time for sources and states to maintain quality testing and review procedures.

i. Particulate-bound mercury; Appendix A to Subpart UUUUU

EPA's proposal allows facilities to ignore particulate-bound mercury emissions when using a Continuous Emissions Monitoring System (CEMS) to quantify emissions, as indicated in the proposed Appendix A to Subpart UUUUU—Hg Monitoring Provisions (which only accounts for vapor phase mercury emissions). Demonstrating compliance without accounting for particulate-bound mercury is not appropriate, because particulate-bound mercury can constitute a substantial fraction of total mercury emissions. To illustrate, Attachment D provides monitoring results at Massachusetts' facilities that found variable amounts of particulate-bound mercury emissions, with particulate-bound mercury accounting for as much as 40 percent of total mercury.

The NESCAUM states encourage EPA to require total mercury emissions to be the basis of compliance demonstrations. For example, the Massachusetts Department of Environmental Protection's final mercury emissions regulation at 310 CMR 7.29(5)(a)3.g.ii. specifies:

> If mercury CEMS capable of measuring only vapor-phase mercury are installed at a unit for purposes of determining compliance with the standards in 310 CMR 7.29(5)(a)3.c., e. and f., total mercury shall be determined by taking into account the average particulate-bound mercury measured during the most recent stack test on that unit in combination with the total vapor-phase mercury measured by the CEMS until such time as mercury CEMS to measure particulate-bound mercury are installed at a unit.

To ensure the full extent of achievable mercury reductions, EPA should require a methodology that quantifies better total flux of mercury in all forms.

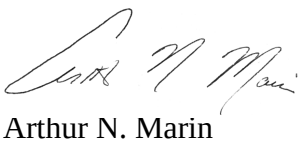
IX. Summary

In summary, the NESCAUM states agree with EPA's December 2000 finding that regulating HAP emissions from EGUs under Clean Air Act § 112 is "appropriate and necessary," agree with EPA's current confirmation of the December 2000 finding, and agree with EPA that its subsequent reversal of this finding in 2005 was in error. Now, with the proposed Utility MACT rule, EPA is approaching the long-standing problem of coal- and oil-fired power plant HAP emissions in a manner more consistent with the statutory requirements of the Clean Air Act, and more protective of public health.

As proposed, the Utility MACT Rule will have public health and environmental benefits that far exceed its projected costs. These requirements are achievable within a reasonable timeframe, and there are a number of technology options available to power plant owners to accomplish the necessary HAP reductions. As examples, we provide in our comments information on the real world experience in several NESCAUM states that already require mercury reductions from in-state coal-fired power plants, with many programs going beyond the mercury reductions envisioned in EPA's proposed rule. These experiences demonstrate that EPA's proposed mercury MACT limits are achievable, and that even greater reductions may be possible in light of the states' experience. Furthermore, based on our review of the performance test data of the top performing 12 percent of units used by EPA and on consideration of what could be viewed as expected variability among "complying units," the NESCAUM states request EPA review its MACT calculations to reflect the considerations we identify in these comments.

In light of the unnecessarily protracted time it has taken to get to this point, and in recognition of the many health and environmental benefits of reducing power plant HAP emissions, we urge EPA to move expeditiously to finalize appropriate and achievable coal- and oil-fired power plant MACT standards so that the public health and welfare benefits begin to accrue as soon as possible. If you have any questions or require further information, please contact Paul Miller, NESCAUM Deputy Director, at 617-259-2016.

Sincerely,



Arthur N. Marin
Executive Director

Encs:
Attachments A-D
Attached Report: *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants*

cc: NESCAUM directors
NESCAUM Stationary Sources & Permitting Committee
NESCAUM Attainment Planning Committee

Attachment A
NESCAUM State Mercury Programs for Coal Power Plants[1]

State	Control Program	Monitoring Requirements
Connecticut	Emissions from coal-fired electric generating units (EGUs) are limited to 0.6 lbs Hg/TBtu or a 90% reduction pursuant to Connecticut General Statutes section 22a-199. The owner or operator of any coal-fired EGU is required to apply for and obtain a new source review permit pursuant to section 22a-174-3a(n) of the Regulations of Connecticut State Agencies.	Compliance is determined through quarterly stack testing.
Massachusetts	Adopted rule 310 CMR 7.29. In 2001, as part of a multi-pollutant regulation controlling sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury, Massachusetts initially established annual mercury emission caps for the state's coal-fired power plants at the then-current level of emissions. To reduce emissions, a 2-phase mercury reduction program was established in 2004. Phase 1 required a minimum 85% capture as compared to 2001-2002 inlet emissions or a maximum 0.0075 lb/GWh rate by 1/1/2008. Phase 2 requires a minimum 95% capture as compared to 2001-2002 inlet emissions or a maximum 0.0025 lb/GWh rate by 10/1/2012. Averaging between units at the same facility is allowed.	Required continuous Hg monitoring by 1/1/2008.
New Hampshire	RSA Chapter 125-O Multiple Pollutant Reduction Program requires reductions in mercury and other pollutants from coal-burning EGUs (Merrimack 1 and 2 and Schiller 4, 5, and 6) by 2013. This statute requires installation of a wet FGD system (scrubber) at Merrimack 1 and 2 to control mercury emissions at the maximum sustainable rate by July 1, 2013. For all affected units, the aggregated total annual reduction in mercury emissions shall be a minimum of 80 percent below the baseline mercury input.	Annual baseline Hg input determined by monthly samples of coal used at affected units. A minimum of four stack tests at affected units used to determine annual baseline Hg emissions. After baseline emissions determined, stack tests twice a year used to determine emissions performance. CEMS required to be installed when federal performance specification takes effect.

[1] Extracted from information compiled by the National Association of Clean Air Agencies (NACAA), February 2011, and updated by the NESCAUM states in May 2011.

State	Control Program	Monitoring Requirements
New Jersey	Adopted state rule under NJSA 7:27-27 requires control efficiency of 90% or 3 mg/MWh by 12/15/2007 for coal-fired boilers of any size. A multi-pollutant approach can reduce the initial reduction required and extend compliance to 12/15/2012.	Stack testing used for compliance purposes. Hg CEMS are installed at three units but are not QA/QC'd and not used for determining compliance.
New York	On 1/27/07, NYSDEC promulgated 6NYCRR Part 246 for the control of mercury emissions from coal-fired electric utility steam generating units that incorporates a Phase I emission cap in the years 2010-2014 and beginning in 2015 establishes a unit-based emission limit for each applicable unit. Phase I of the state proposal imposed annual facility-wide mercury emission limitations, based upon the state mercury budget EPA distributed to NY under the vacated CAMR. The annual facility-wide emission limitations will be in effect from 2010 to 2014. Starting in 2015, Phase II, in conjunction with other electric sector regulations such as the Regional Greenhouse Gas Initiative (RGGI) and EPA's Cross-State Air Pollution Rule, the state mercury regulation will establish a facility-wide emission limit for Hg 0.6 lbs Hg/TBtu.	Annual stack testing was required for the years 2008 and 2009. Hg CEMS have been installed and operating since 2009. New York has three facilities operating CEMS and two facilities using sorbent tube methodology.

Attachment B
Emission Controls on Coal EGUs in NESCAUM Region

Power Plant, Location	Unit	Nameplate Capacity (MW)[1]	Initial Year of Operation[1]	Controls[2]	Needed new controls to meet Hg limits?	Notes
PSEG Bridgeport Harbor, CT	3	400	1968	Existing ESP; new ACI, pulse-jet fabric filter	Yes	Facility also burns lower sulfur Adaro (Indonesian) coal
AES Thames, CT	1 & 2	213.9	1989	Circulating fluidized bed boiler with dry limestone injection and fabric filter	No	Has complied with CT mercury rules but has been shut down (Jan. 2011) while in bankruptcy
Salem Harbor, MA	1	81.9	1951	Existing ESP-SNCR	No for Phase 1, unit will shut down prior to Phase 2	
Salem Harbor, MA	2	82	1952	Existing ESP-SNCR	No for Phase 1, unit will shut down prior to Phase 2	
Salem Harbor, MA	3	165.7	1958	Existing ESP-SNCR	No for Phase 1, unit may shut down prior to Phase 2	
Mt. Tom, MA	1	136	1960	Existing ESP; new SCR, dry scrubber, fabric filter	Yes	
Brayton Point, MA	1	243	1963	Existing ESP; new SCR, dry sorbent injection, spray dry absorption, fabric filter	Yes	
Brayton Point, MA	2	240	1964	Existing ESP; new dry sorbent injection, spray dry absorption, fabric filter	Yes	

Power Plant, Location	Unit	Nameplate Capacity (MW)[1]	Initial Year of Operation[1]	Controls[2]	Needed new controls to meet Hg limits?	Notes
Brayton Point, MA	3	612	1969	Existing ESP, new SCR; with dry sorbent injection, FGD (dry scrubber), and fabric filter under construction	Yes	
Somerset, MA	8	100	1959		Not applicable	Shut down
Merrimack, NH	1	113.6	1960	SCR, ESP, fuel sulfur content limits; FGD (wet scrubber) system to be fully operational by July 2013	Yes	
Merrimack, NH	2	345.6	1968	SCR, ESP, fuel sulfur content limits; FGD (wet scrubber) system to be fully operational by July 2013	Yes	
Schiller, NH	4	50	1952	ESP, low-NO_x burners, fuel sulfur content limits	No (NH law allows mercury reductions achieved at Merrimack to count towards Schiller requirements)	Under alternative operating scenarios, these controls may also be used: SNCR, overfire air, flyash re-injection
Schiller, NH	5	50	1955	SNCR, limestone injection, fabric filter	Same as unit 4 above	Replaced existing coal unit with biomass unit in 2006
Schiller, NH	6	50	1957	ESP, low-NO_x burners, fuel sulfur content limits	Same as unit 4 above	Under alternative operating scenarios, these controls may also be used: SNCR, overfire air, flyash re-injection
PSEG Hudson, NJ	2	659.7	1968	ESP, baghouse, FGD, ACI, low-NO_x burners, SNCR, SCR	Yes	
Mercer, NJ	1	326.4	1960	ESP, baghouse, spray dry absorption, ACI, SCR	Yes	
Mercer, NJ	2	326.4	1961	ESP, baghouse, spray dry absorption, ACI, SCR	Yes	

Power Plant, Location	Unit	Nameplate Capacity (MW)[1]	Initial Year of Operation[1]	Controls[2]	Needed new controls to meet Hg limits?	Notes
Deepwater, NJ	8	73.5	1954	Baghouse, low-NO_x burners	Not applicable	Switched to natural gas in 2010
B L England, NJ	1	136	1962	ESP, SNCR, overfire air	No	
B L England, NJ	2	163.2	1964	ESP, FGD (wet lime scrubbing), sorbent injection (Hg control), SNCR, overfire air, SCR	Yes	Permitted SCR has not been installed yet
Chambers Cogeneration LP, NJ	1	112	1994	Baghouse, spray dray absorption, low-NO_x burners, SCR	No	Two coal boilers serving one steam turbine
Chambers Cogeneration LP, NJ	2	112	1994	Baghouse, spray dray absorption, low-NO_x burners, SCR	No	
Logan Generating Company LP, NJ	1	242.3	1994	Baghouse, spray dray absorption, low-NO_x burners, SCR	No	
Howard Down, NJ	10	25	1970	Low-NO_x burners	Not applicable	Shut down in 2010
AES Cayuga, NY	1	155.3	1955	SCR, ESP, FGD (wet scrubber)	No, not until 2015	
AES Cayuga, NY	2	167.2	1955	SCR, ESP, FGD (wet scrubber)	No, not until 2015	
AES Greenidge, NY	4	112.5	1953	SNCR, ACI, FGD (dry scrubber)	No, not until 2015	
AES Somerset, NY	S-00001	655.1	1984	SCR, ESP, FGD (wet scrubber)	No, not until 2015	
AES Westover, NY	W-00003	75	1951	ESP	No, not until 2015	
C R Huntley Generating Station, NY	67	218	1957	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	
C R Huntley Generating Station, NY	68	218	1958	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	
Dunkirk Steam Generating, NY	1	96	1950	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	
Dunkirk Steam Generating, NY	2	96	1950	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	

Power Plant, Location	Unit	Nameplate Capacity (MW)[1]	Initial Year of Operation[1]	Controls[2]	Needed new controls to meet Hg limits?	Notes
Dunkirk Steam Generating, NY	3	217.6	1959	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	
Dunkirk Steam Generating, NY	4	217.6	1960	SNCR, fabric filter, capable of dry limestone injection/ACI	No, not until 2015	
Danskammer Generating, NY	3	147.1	1959	ESP	No, not until 2015	
Danskammer Generating, NY	4	239.4	1967	ESP	No, not until 2015	
Samuel A. Carlson Generating Station, NY	3	28.7	1951	ESP, set up for ACI	No, not until 2015	
Samuel A. Carlson Generating Station, NY	4	25.0	1968	ESP, set up for ACI	No, not until 2015	
Trigen Syracuse Energy, NY	1	90.6	1991	FGD (dry scrubber), fabric filter	No, not until 2015	
Niagara Generation, NY	1	56	1991	FGD (dry scrubber), fabric filter	No, not until 2015	
Black River Generation, NY	1	55.5	1989	FGD (dry scrubber), fabric filter	No, not until 2015	

[1] U.S. Energy Information Administration, Form EIA-860 "Annual Electric Generator Report" (2009), available at http://www.eia.gov/cneaf/electricity/page/eia860.html.
[2] Information provided by state air agencies in NESCAUM region.

Attachment C
Quarterly Stack Emission Test Results (2008-2009)
B.L. England Generating Station, New Jersey

September 17, 2008

M E M O R A N D U M

TO: Michael Klein

FROM: John Kitson

SUBJECT: RC Cape May Holdings
Stack Emission Test Program
APC ID No. 73242
BOP No. 070005
TST No. 070006

Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility on March 6th and 7th, 2008. The purpose of the tests was to quantify the emissions of mercury compounds (Hg) being discharged to the atmosphere from a coal fired utility boiler designated as Unit 2. Inlet testing was conducted in order to determine the Unit's removal efficiency (RE). The test results were compared to the allowables referenced in the Operating Permit (BOP).

The results are as follows.

Emission Data

Hg	Run 1	Run 2	Run 3	Average	Allowable
Inlet A					
ug/dscm	7.15	6.80	8.87	---	---
lb/hr	0.0064	0.0060	0.0078	---	---
Inlet B					
ug/dscm	6.63	7.40	8.36	---	---
lb/hr	0.0057	0.0067	0.0073	---	---
Outlet					
ug/dscm	0.25	0.17	0.25	---	---
lb/hr	0.00047	0.00034	0.00050	0.00044	0.045
mg/MW-hr *	1.46	1.06	1.55	1.36	3.00
RE					
% (lb/hr basis)	96.1	97.3	96.7	96.7	≥90

* As calculated by BTS. Testers incorrectly used gross MW instead of net MW in their calculations.

Process Data

Output	Run 1	Run 2	Run 3	Allowable
MW (gross)	160	160	160	---
MW (net)	146	146	146	---
Heat Input				
MMBtu/hr	1,549	1,538	1,548	≤1,600
Carbon Inj. Rate				
lb/hr	415	414	412	---

The review indicated substantially the same results as those reported by Catalyst except where noted. Compliance was demonstrated for each tested parameter. An audit sample for mercury was analyzed and was found to meet the acceptance criteria. Process data was supplied by the facility.

June 2, 2009

To: Michael Klein

From: Larry Gurley

Subject: RC Cape May Holding, LLC – Beasley's Point
Stack Emission Test Program
APC ID No. 73242
BOP No. 070005
TST No. 080003

Between June 30 and August 5, 2008, Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility. The purpose of the testing was to determine mass emission levels of particulate matter (PM), particulate matter less than ten microns (PM-10), ammonia (NH_3), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), hydrogen chloride (HCl), total fluorides (F), mercury (Hg), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni) from one coal fired steam generating unit, Unit 2. Inlet testing was performed on Unit 2 to determine the removal efficiency of mercury. The test results were then compared to the Operating Permit (BOP) to determine compliance status. Also, as part of this test program, four multi metals audits, two mercury audits, two hydrogen chloride audits and one sulfuric acid audit sample was provided to the consultant.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
TSP					
Filterable					
gr/dscf	3.71 E-3	3.82 E-3	2.54 E-3	3.36 E-3	----
lb/hr	15.9	16.4	11.0	14.4	160
Condensable [1]					
gr/dscf	6.24 E-3	6.60 E-3	5.47 E-3	6.10 E-3	----
lb/hr	26.8	28.3	23.7	26.3	----
Worst-Case PM-10					
gr/dscf	9.95 E-3	1.04 E-2	8.01 E-3	9.45 E-3	----
lb/hr	42.8	44.8	34.7	40.8	217.47
NH_3					
ppmvd	0.38	0.33	0.30	0.34	----
ppmvd @ 7% O_2	0.46	0.40	0.35	0.40	20 [2]
lb/hr	0.50	0.43	0.38	0.44	----
SO_2					
gr/dscf	0.186	0.205	0.212	0.201	----
lb/hr	745	865	897	832	1,336 [2]
H_2SO_4					
gr/dscf	0.004	0.004	0.004	0.004	----
lb/hr	16.4	16.7	15.2	16.1	158
HCl					
gr/dscf	2.62 E-4	1.66 E-4	1.80 E-4	1.03 E-4	----
lb/hr	1.10	0.70	0.76	0.85	11
Total F (as HF**)**					
gr/dscf	< 3.64 E-4	< 3.60 E-4	< 3.59 E-4	< 3.61 E-4	----
lb/hr	< 1.53	< 1.51	< 1.51	< 1.52	57.7

[1] These values were calculated by BTS. The original, reported values included non-detect fractions being added to the total.
[2] Allowable is based on the three run average.
A '<' sign indicates that all sample fractions were non-detect. The detection limit was used for calculation purposes.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
As [1]					
ug/dscm	3.16	2.08	1.88	2.37	----
lb/hr	5.4 E-3	3.8 E-3	3.4 E-3	4.2 E-3	3.9
Be [1]					
ug/dscm	< 0.29	< 0.28	< 0.28	< 0.28	----
lb/hr	< 5.0 E-4	< 5.0 E-4	< 5.0 E-4	< 5.0 E-4	0.02
Cd [1]					
ug/dscm	< 0.29	< 0.28	< 0.28	< 0.28	----
lb/hr	< 5.0 E-4	< 5.0 E-4	< 5.0 E-4	< 5.0 E-4	1.1
Cr [1]					
ug/dscm	8.66	1.04	6.45	5.38	----
lb/hr	1.5 E-2	1.9 E-3	1.2 E-2	9.6 E-3	11.1
Co [1]					
ug/dscm	1.37	0.44	0.38	0.73	----
lb/hr	2.3 E-3	8.0 E-4	6.9 E-4	1.3 E-3	0.065
Pb [1]					
ug/dscm	1.44	0.97	0.89	1.10	----
lb/hr	2.5 E-3	1.8 E-3	1.6 E-3	2.0 E-3	13.7
Mn [1]					
ug/dscm	13.1	15.2	1,205	4,11	----
lb/hr	2.2 E-2	2.7 E-2	2.2	0.75	5.6
Ni [1]					
ug/dscm	35.2	13.6	10.0	19.6	----
lb/hr	6.0 E-2	2.5 E-2	1.8 E-2	3.4 E-2	4.2

[1] These values were recalculated by Catalyst. The original, reported values included non-detect fractions being added to the total.
A '<' sign indicates that all sample fractions were non-detect. The detection limit was used for calculation purposes.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
INLET					
A – Side					
Hg [1]					
ug/dscm	7.66	7.76	7.44	7.62	----
lb/hr	6.1 E-3	6.3 E-3	5.9 E-3	6.1 E-3	----
mg/MW-hr [2]	18.7	19.2	18.1	18.7	----
B – Side					
Hg [1]					
ug/dscm	18.7	8.52	8.22	11.8	----
lb/hr	1.6 E-2	7.2 E-3	6.8 E-3	1.0 E-2	----
mg/MW-hr [2]	49.1	22.0	20.8	30.6	----
Total Hg [1]					
ug/dscm	26.4	16.3	15.7	19.5	----
lb/hr	2.2 E-2	1.4 E-2	1.3 E-2	1.6 E-2	----
mg/MW-hr [2]	67.8	41.2	38.9	49.3	----
OUTLET					
Hg [1]					
ug/dscm	0.27	0.19	0.16	0.21	----
lb/hr	4.5 E-4	3.4 E-4	2.8 E-4	3.6 E-4	0.045
mg/MW-hr [2]	1.38	1.04	0.86	1.09	3.00
% RE (lb/hr)	98.0	97.6	97.8	97.8	90

[1] These values were recalculated by Catalyst. The original, reported values included non-detect fractions being added to the total.
[2] Values calculated by BTS. Catalyst calculated these values using gross MW instead of net MW.

Technical Services calculations, using the raw data supplied, indicated the same results as those presented by Catalyst Air Management, Inc., with the exceptions stated previously. The results of the test program demonstrated that all mass emission levels for this operation were in compliance with the referenced allowables. All audit samples passed the method acceptance criteria.

Production data during the mercury stack tests is summarized as follows.

Production Data				
Unit 2				
	Run 1	**Run 2**	**Run 3**	**Allowable**
Gross MW	162	164	163	----
Net MW	148	149	148	155
Heat Input * (MMBtu/hr)	1,537	1,653	1,652	1,600
Carbon Inj. Rate (lb/hr)	343	310	357	----

* Heat inputs were calculated by BTS using stack flow rates, oxygen content and fuel factors.

Unit 2: Coal Analysis

Mercury	Run 1	Run 2	Run 3
mg/kg, dry	0.091	0.090	0.096

June 10, 2009

To: Michael Klein

From: Larry Gurley

Subject: RC Cape May Holding, LLC – Beasley's Point
Stack Emission Test Program
APC ID No. 73242
BOP No. 070005
TST No. 080005

On September 30 and October 1, 2008, Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility. The purpose of the testing was to determine mass emission levels of mercury (Hg) from one coal fired steam generating unit, Unit 2. Inlet testing was performed to determine the removal efficiency of mercury. The test results were then compared to the Operating Permit (BOP) to determine compliance status. Also, as part of this test program, one mercury audit sample was provided to the consultant.

The following are the results of the testing.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
INLET					
A – Side					
Hg [1]					
ug/dscm	7.22	7.70	8.27	7.73	----
lb/hr	6.40 E-3	6.84 E-3	7.33 E-3	6.86 E-3	----
mg/MW-hr	18.7	20.0	22.9	20.5	----
B – Side					
Hg [1]					
ug/dscm	7.33	6.28	8.08	7.23	----
lb/hr	5.50 E-3	4.69 E-3	6.04 E-3	6.41 E-3	----
mg/MW-hr	16.1	13.7	18.9	16.2	----
Total Hg [1]					
ug/dscm	14.6	14.0	16.4	15.0	----
lb/hr	1.19 E-2	1.15 E-2	1.34 E-2	1.23 E-2	----
mg/MW-hr	34.8	33.7	41.8	36.8	----
OUTLET					
Hg [1]					
ug/dscm	0.653	0.534	0.465	0.551	----
lb/hr	1.28 E-3	1.02 E-3	9.02 E-4	1.07 E-3	0.045 [2]
mg/MW-hr	**3.75**	2.98	2.82	**3.18**	3.00
% RE (lb/hr)	**89.2**	91.2	93.2	91.2	90

[1] These values were recalculated by BTS. The original, reported values included non-detect fractions being added to the total.
[2] Allowable is based on the three run average.

Technical Services calculations, using the raw data supplied, indicated the same results as those presented by Catalyst Air Management, Inc., with the exceptions stated previously. The results of the test program demonstrated that all mass emission levels for this operation were in compliance with the referenced allowables with the exception of mercury mg/MW-hr (Run 1 and average) and %RE (Run 1). However, the allowables for these two criteria are based on an annually weighted average. The results presented in the previous table are for this quarter's emissions only. The audit sample passed the method acceptance criteria.

Production data during the mercury stack tests is summarized as follows.

Production Data				
Unit 2				
	Run 1	**Run 2**	**Run 3**	**Allowable**
Gross MW	170	171	160	170
Net MW	155	155	145	----
Heat Input (MMBtu/hr)	1,755	1,722	1,704	1,600
Carbon Inj. Rate (lb/hr)	368	373	378	----

* Heat inputs were calculated by BTS using stack flow rates, oxygen content and an assumed coal fuel factor.

Unit 2: Coal Analysis

Mercury	Run 1	Run 2	Run 3
mg/kg, dry	0.121	0.142	0.142

September 30, 2009

To: Michael Klein

From: Frank Matula

Subject: RC Cape May Holding, LLC – Beesley's Point
Stack Emission Test Program
APC ID No. 73242
BOP No. 070005
TST No. 080006
Unit 2 Testing for Hg and Trace Metals

On November 24 and 25, 2008, Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility. The purpose of the testing was to determine mass emission levels of mercury (Hg) and trace metals from one coal fired steam generating unit, Unit 2. Inlet testing was performed to determine the removal efficiency of mercury. The test results were then compared to the Operating Permit (BOP) to determine compliance status. Also, as part of this test program, one mercury audit sample was provided to the consultant.

The following are the results of the testing.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
INLET					
A – Side					
Hg [1]					
ug/dscm	11.3	7.45	10.8	29.6	----
lb/hr	9.42E-3	6.42E-3	9.44E-3	8.43E-3	----
mg/MW-hr	28.1	19.4	28.5	25.3	----
B – Side					
Hg [1]					
ug/dscm	6.65	10.6	9.73	8.99	----
lb/hr	5.63E-3	8.97E-3	8.21E-3	7.60E-3	----
mg/MW-hr	16.8	27.1	24.8	22.9	----
Total Hg [1] (A+B**)**					
lb/hr	1.51E-2	1.54E-2	1.76E-2	1.60E-2	----
mg/MW-hr	44.9	46.5	53.3	48.2	----
OUTLET					
Hg [1]					
ug/dscm	0.072	0.088	0.058	0.073	----
lb/hr	1.38E-4	1.72E-4	1.11E-4	1.40E-4	0.045 [2]
mg/MW-hr	0.412	0.519	0.336	0.422	3.00 [3]
% RE (lb/hr)	99.1	98.9	99.4	99.1	90 [3]

[1] These values were recalculated by BTS to include only the detected fractions. The original reported values included non-detect fractions added to the total.
[2] Allowable is based on the three run average.
[3] Allowable is based on an annual weighted average.

Unit 2 Metals [1]	Run 1	Run 2	Run 3	Average	Allowable
Arsenic					
lbs/hr	5.9E-3	3.2E-3	2.0E-3	3.7E-3	3.9
Beryllium					
lbs/hr *	ND	ND	ND	ND	0.02
Cadmium					
lbs/hr	1.8E-3	1.3E-3	3.1E-3	2.1E-3	1.1
Chromium					
lbs/hr	8.4E-2	4.6E-2	2.9E-2	5.3E-2	11.1
Cobalt					
lbs/hr	1.6E-3	1.6E-3	1.1E-3	1.4E-3	0.065
Copper					
lbs/hr	1.8E-2	9.6E-3	8.5E-3	1.2E-2	0.8
Lead					
lbs/hr	5.5E-3	3.3E-3	2.5E-3	4.0E-3	13.7
Manganese					
lbs/hr	4.8E-2	3.2E-2	3.3E-2	3.8E-2	5.6
Nickel					
lbs/hr	8.3E-2	3.5E-2	2.7E-2	4.8E-2	4.2
Selenium					
lbs/hr	4.3E-3	6.6E-3	3.3E-3	4.7E-3	0.08

* All fractions were below the analytical detection limit.

[1] These values were recalculated by BTS to exclude blank corrections. The original reported values included blank corrections. The laboratory had combined front half and back half fractions and when this is done, proper blank corrections cannot be calculated. However, the results can be accepted since compliance was achieved without blanks subtracted.

Technical Services calculations, using the raw data supplied, indicated the same results as those presented by Catalyst Air Management, Inc., with the exceptions noted. The results of the test program demonstrated that all mass emission levels for this operation were in compliance with the referenced allowables. However, the allowables for mg/MW-hr and %RE are based on an annual weighted average. The results presented in the previous table are for the 2008 4th quarter emissions test only. The audit sample passed the method acceptance criteria.

Production data during the mercury stack tests is summarized as follows.

Production Data				
Unit 2				
	Run 1	**Run 2**	**Run 3**	**Allowable**
Gross MW	167	165	165	170
Net MW	152	150	150	----
Heat Input (MMBtu/hr) *	1,649	1,684	1,675	1,600
Carbon Inj. Rate (lb/hr)	367	358	370	----

* Heat inputs were calculated by BTS using stack flow rates, oxygen content and an assumed coal fuel factor.

Unit 2: Coal Analysis

Mercury	Run 1	Run 2	Run 3
mg/kg, dry	0.103	0.095	0.125

October 13, 2009

M E M O R A N D U M

TO: Michael Klein

FROM: Frank Matula

SUBJECT: RC Cape May Holdings
Stack Emission Test Program – 1st Quarterly Hg Testing
APC ID No. 73242
BOP No. 080002
TST No. 090002

Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility on March 17, 2009. The purpose of the tests was to quantify the emissions of mercury compounds (Hg) being discharged to the atmosphere from a coal fired utility boiler designated as Unit 2. Inlet testing was conducted in order to determine the Unit's removal efficiency (RE). The test results were compared to the allowables referenced in the Operating Permit (BOP).

The results are as follows.

Emission Data

Hg	Run 1	Run 2	Run 3	Average	Allowable
Inlet A					
ug/dscm	1.52	1.48	1.67	---	---
lb/hr	0.0013	0.0013	0.0015	---	---
Inlet B					
ug/dscm	1.15	1.14	0.98	---	---
lb/hr	0.0010	0.00098	0.00085	---	---
Outlet					
ug/dscm	0.13	0.28	0.14	---	---
lb/hr	0.00027	0.00057	0.00028	0.00037	---
mg/MW-hr	0.80	1.71	0.85	1.12	3.00 [1]
RE					
% (lb/hr basis)	88.3	75.0	88.1	83.8	≥90 [1]

[1] Allowable is based on an annual weighted average. One of the two standards needs to be met.

Process Data

Output	Run 1	Run 2	Run 3	Allowable
MW (gross)	165	165	164	170 *
MW (net)	151	151	150	---
Heat Input				
MMBtu/hr **	1,754	1,732	1,737	≤1,600
Carbon Inj. Rate				
lb/hr	212	209	207	---
Coal Analysis				
Mercury				
ug/kg, dry	0.104	0.109	0.107	

* As stated in the test report.

* Heat inputs calculated by BTS using stack flow rates, oxygen content and as assumed coal fuel factor.

The review indicated substantially the same results as those reported by Catalyst. Compliance was demonstrated for the mg/MW-hr limit, but the alternate removal efficiency limit did not meet the Permit requirement. The allowables were based on an annual weighted average. The results of this test program were for the 2009 1st quarter. An audit sample for mercury was analyzed and was found to meet the acceptance criteria. Process data was supplied by the facility.

October 13, 2009

M E M O R A N D U M

TO: Michael Klein

FROM: Frank Matula

SUBJECT: RC Cape May Holdings
Stack Emission Test Program – 2nd Quarter 2009 Hg Testing
APC ID No. 73242
BOP No. 080001
TST No. 090003
Subject Item: GR3, U2

Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility on July 9 and 10, 2009. The purpose of the tests was to quantify the emissions of mercury (Hg) being discharged to the atmosphere from a coal fired utility boiler designated as Unit 2. Inlet testing was conducted in order to determine the Unit's removal efficiency (RE). The test results were compared to the allowables referenced in the Operating Permit (BOP).

The results are as follows.

Emission Data

Hg	Run 1	Run 2	Run 3	Average	Allowable
Inlet A					
ug/dscm	13.2	16.5	7.26	---	---
lb/hr	0.0094	0.012	0.0052	---	---
Inlet B					
ug/dscm	5.19	14.6	9.13	---	---
lb/hr	0.0035	0.010	0.0062	---	---
Outlet					
ug/dscm	0.04	0.05	0.04	---	---
lb/hr	0.000067	0.000084	0.000063	0.000071	---
mg/MW-hr	0.20	0.25	0.18	0.21	3.00 [1]
RE					
% (lb/hr basis)	99.5	99.6	99.5	99.5	≥90 [1]

[1] Allowable is based on an annual weighted average. One of the two standards needs to be met.

Process Data [(2)]

Output	Run 1	Run 2	Run 3	Allowable
MW (gross)	169	169	169	170 *
MW (net)	155	156	156	---
Heat Input				
MMBtu/hr [(1)]	1,753	1,751	1,777	≤1,600
MMBtu/hr	1,889	1,824	1,856	
Carbon Inj. Rate				
lb/hr	375	341	372	---
Coal Analysis				
Mercury				
ug/kg, dry	0.134	0.124	0.131	---

[(1)] Heat inputs calculated by BTS using stack flow rates, oxygen content and an assumed coal fuel factor.
[(2)] Facility provided data.
* As stated in the test report.

The review indicated substantially the same results as those reported by Catalyst. Compliance was demonstrated for mercury. The allowables for mg/MW-hr and percent RE were based on an annual weighted average. The results of this test program were for the 2009 2nd quarter emissions. An audit sample for mercury was analyzed and was found to meet the acceptance criteria.

August 5, 2010

To: Michael Klein

From: Neil Nissim

Subject: RC Cape May Holdings, LLC – Beesley's Point
Stack Emission Test Program
PI No. 73242
BOP No. 080002
TST No. 090006

Catalyst Air Management, Inc. conducted stack emission tests at the above referenced facility on September 1-3, 2009. The purpose of the testing was to determine mass emission levels of total suspended particulate (TSP), worst-case particulate matter less than ten microns (worst-case PM-10, the sum of TSP and condensible particulate matter, CPM), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), ammonia (NH_3), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), hydrogen chloride (HCl), total fluorides (F), total dioxins/furans, polynuclear aromatic hydrocarbons (PAH) as benzo(a)pyrene (B(a)P), polycyclic organic matter (POM), mercury (Hg), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), copper (Cu), lead (Pb), manganese (Mn) and nickel (Ni) from one coal fired steam generating unit, Unit 2. Inlet testing was conducted at Unit 2 to determine the removal efficiency of mercury. The test results were then compared to the Operating Permit (BOP) to determine compliance status. Also, as part of this test program, four multi metals audits, two Hg audits, two HCl audits, one H_2SO_4 audit and one SO_2 audit sample was provided to the consultant.

Where an allowable basis was stated in the BOP, the limits include footnotes in the following tables. Other limits without footnotes did not have a clearly indicated compliance basis in the Permit.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
TSP					
gr/dscf	0.0203	0.0126	0.0126	---	---
lb/hr	71.3	41.9	42.4	---	160 [3]
CPM					
gr/dscf	0.0123	0.0101	0.0096	---	---
lb/hr	43.0	33.4	32.2	---	---
Worst-Case PM-10					
gr/dscf	0.0326	0.0227	0.0222	---	---
lb/hr	114	75.3	74.6	---	217.47 [3]
NOx (as NO_2)					
ppmvd @ 7% O_2	215	216	215	215	341 [2]
lbs/hr	569	572	569	570	960 [2]
CO					
ppmvd @ 7% O_2	11.6	10.2	13.4	11.7	100 [2]
lbs/hr	18.7	16.4	21.5	---	115 [3]
VOC (as CH_4) [1]					
ppmvd @ 7% O_2	1.12	1.15	1.46	1.24	50 [2]
lbs/hr	1.02	1.05	1.34	---	20 [3]
NH_3					
ppmvd @ 7% O_2	0.58	0.34	0.24	0.39	20 [2]
lb/hr	0.57	0.33	0.23	0.38	---
SO_2					
gr/dscf	0.152	0.143	0.143	0.146	
lb/hr	486	443	449	459	1,336 [2]
H_2SO_4					
gr/dscf	0.002	0.001	0.001	0.001	---
lb/hr	6.2	2.8	3.9	4.3	158
HCl					
ppmvd	0.31	0.39	0.14	0.28	---
lb/hr	0.66	0.84	0.30	0.60	11
Total F (as HF)					
ppmvd	<0.0005	<0.0005	<0.0004	<0.0005	---
lb/hr	<1.50	<1.50	<1.42	<1.47	57.7

[1] As calculated by BTS; consultant's results were on a propane basis.
[2] Allowable is based on the three run average.
[3] Allowable is based on each test run.
A '<' sign indicates that all sample fractions were non-detect. The detection limit was used for calculation purposes.

Unit 2					
Total dioxins/furans [1]	**Run 1**	**Run 3**	**Run 4**	**Average**	**Allowable**
ng/dscm	0.011	0.007	0.055	0.024	
lb/hr	1.55E-08	9.65E-09	7.93E-08	3.48E-08	2.11E-07
PAH (as B(a)P) [2]					
ppmvd	2.04E-04	9.73E-05	8.32E-05	1.28E-04	
lb/hr	3.04E-03	1.40E-03	1.25E-03	1.90E-03	0.39
POM [3]					
1-Methylnaphalene					
ug/dscm	0.383	0.121	0.096	0.200	---
lb/hr	5.5E-04	1.7E-04	1.4E-04	2.9E-04	---
2-Methylnaphalene					
ug/dscm	0.733	0.260	0.195	0.396	---
lb/hr	1.0E-03	3.6E-04	2.8E-04	5.5E-04	---
Biphenyl					
ug/dscm	0.156	0.073	0.096	0.108	---
lb/hr	2.2E-04	1.0E-04	1.4E-04	1.5E-04	---
Fluoranthene					
ug/dscm	0.041	<	<	0.041	---
lb/hr	5.8E-05	<	<	5.8E-05	---
Naphthalene					
ug/dscm	0.766	0.530	0.457	0.584	---
lb/hr	1.1E-03	7.3E-04	6.5E-04	8.2E-04	---
Phenanthrene					
ug/dscm	0.054	0.034	0.035	0.041	---
lb/hr	7.6E-05	4.7E-05	5.1E-05	5.8E-05	---

[1] As calculated by BTS not using any equivalency factors and assigning all non-detects as zero.

[2] As calculated by BTS assigning all non-detects as zero; consultant did not report total PAH as B(a)P.

[3] Only detected POM listed in the table.

< Less than the detection limit

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
INLET					
A – Side					
Hg [1]					
ug/dscm	11.3	11.4	14.6		
lb/hr	0.0071	0.0073	0.0093		
mg/MW-hr	21.1	22.0	28.0		
B – Side					
Hg [1]					
ug/dscm	13.6	9.24	11.1		
lb/hr	0.0086	0.0059	0.0073		
mg/MW-hr	25.7	17.9	21.9		
Total Hg [1]					
lb/hr	0.0157	0.0132	0.0166		
mg/MW-hr	46.8	39.9	49.9		
OUTLET					
Hg [1]					
ug/dscm	0.02	0.03	0.04	0.03	---
lb/hr	3.3E-05	3.5E-05	6.3E-05	4.4E-05	---
mg/MW-hr	0.11	0.11	0.20	0.14	3.00 [2]
% RE (lb/hr)	99.8	99.7	99.6	99.7	90 [2]

[1] These values were reported by Catalyst which include non-detect fractions being added to the total and can be considered conservative.

[2] Based on an annual weighted average.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
As [1]					
ug/dscm	0.6	1.11	0.80	0.84	---
lb/hr	8.5E-04	0.0015	0.0011	0.00115	3.9
Be					
ug/dscm	<0.1	<0.11	<0.11	<0.11	---
lb/hr	<1.5E-04	<1.5E-04	<1.5E-04	<1.5E-04	0.02
Cd					
ug/dscm	<0.10	0.23	0.11[1]	0.15	---
lb/hr	<1.5E-04	3.2E-04	1.5E-04[1]	2.07E-04	1.1
Cr					
ug/dscm	9.88	11.9	5.72	9.17	---
lb/hr	0.014	0.017	0.0080	0.0130	11.1
Co					
ug/dscm	0.71[1]	0.59	0.14[1]	0.48	---
lb/hr	0.0010[1]	8.2E-04	2.0E-04[1]	6.73E-04	0.065
Cu					
ug/dscm	30.2	48.0	20.0	32.73	---
lb/hr	0.043	0.067	0.028	0.046	0.800
Pb					
ug/dscm	1.76	2.85	1.37	1.99	---
lb/hr	0.0025	0.0040	0.0019	0.0028	13.7
Mn					
ug/dscm	16.8	18.1	17.6	17.50	---
lb/hr	0.024	0.025	0.025	0.025	5.6
Ni					
ug/dscm	17.4	14.4	5.62	12.47	---
lb/hr	0.025	0.020	0.0079	0.018	4.2
Se [1]					
ug/dscm	<1.03	1.11	1.07	1.07	---
lb/hr	<0.0015	0.0015	0.0015	0.0015	4.2

[1] These values were reported by Catalyst which include non-detect fractions being added to the total and can be considered conservative.

A '<' sign indicates that all sample fractions were non-detect. The detection limit was used for calculation purposes.

Technical Services calculations, using the raw data supplied, indicated the same results as those presented by Catalyst Air Management, Inc., with the exceptions stated previously. The results of the test program demonstrated that all mass emission levels for this operation were in compliance with the referenced allowables. All audit samples passed the method acceptance criteria.

Run No. 2 for dioxins/furans was invalidated due to a failed post-test leak check caused by a broken probe liner.

NOx testing was supposed to be conducted concurrent with ammonia testing since ammonia is used for NOx control; however, this was not the case. Chemical flow was basically consistent during NOx testing and subsequent ammonia testing.

Production during a portion of testing was witnessed by SRO representative, Mr. Matthew Zehr. His report indicated that during his observation, the facility was operating in accordance with the BOP.

Production data during the mercury stack tests is summarized as follows. Gross and net MW were comparable to the values below throughout the test program.

Production Data				
Unit 2				
	Run 1	**Run 2**	**Run 3**	**Allowable**
Gross MW	154	154	154	---
Net MW	141	141	141	155
Heat Input * (MMBtu/hr)	1510	1440	1460	1,600
Carbon Inj. Rate (lb/hr)	302	316	301	---

* Heat inputs were calculated by BTS using stack flow rates, oxygen content and fuel factors.

Unit 2: Coal Analysis

Mercury	Run 1	Run 2	Run 3
mg/kg, dry	0.104	0.099	0.116

August 19, 2010

To: Michael Klein

From: Hanin Nashif

Subject: RC Cape May Holdings LLC – Beesley's Point
PI No. 73242
BOP No. 090002
TST No. 090008

On December 14 and 15, 2009, emissions testing was conducted at the above referenced facility by Catalyst Air Management, Inc. (Catalyst). The purpose of testing was to determine emissions of mercury (Hg) being discharged from Unit 2. The results of testing were then compared to the referenced Operating Permit (BOP) to determine compliance status.

The summary of the test results and the applicable limits is as follows.

Unit 2					
	Run 1	**Run 2**	**Run 3**	**Average**	**Allowable**
Hg – Inlet A					
lbs/hr	0.0085	0.0095	0.0081	0.0087	----
mg/MW-hr	25.5	28.8	24.6	26.3	----
Hg – Inlet B					
lbs/hr	0.010	0.010	0.0094	0.0099	----
mg/MW-hr	30.6	30.5	28.4	29.8	----
Hg – Inlet Total					
lbs/hr	0.019	0.020	0.018	0.019	----
mg/MW-hr	55.0	57.4	51.2	54.5	----
Hg – Outlet					
lbs/hr	0.00047	0.00067	0.00019	0.00044	----
mg/MW-hr	1.37	1.97	0.56	1.30	3.00 [1]
Removal Efficiency (%) *	97.5	96.5	98.9	97.6	90 [1]

* Calculated by BTS.

[1] Allowable is based on an annual weighted average. One of the two standards needs to be met.

Reported results agreed with those calculated by Technical Services, using supplied raw data, with no substantial differences. Compliance was demonstrated for each tested parameter. An audit sample was analyzed for mercury and was found to meet the acceptance criteria.

Facility supplied production data is summarized below.

Production Data				
	Run 1	**Run 2**	**Run 3**	**Allowable**
Unit 2				
Heat Input (mmbtu/hr) *	1665	1660	1670	1600
Gross/Net Power (MW)	168/155	169/155	169/155	**
Carbon Injection (lbs/hr)	262	271	262	----

* Heat inputs calculated by facility using stack flow rates (from facility monitor), oxygen content (from Catalyst due to a malfunctioning facility oxygen monitor) and an assumed coal fuel factor.

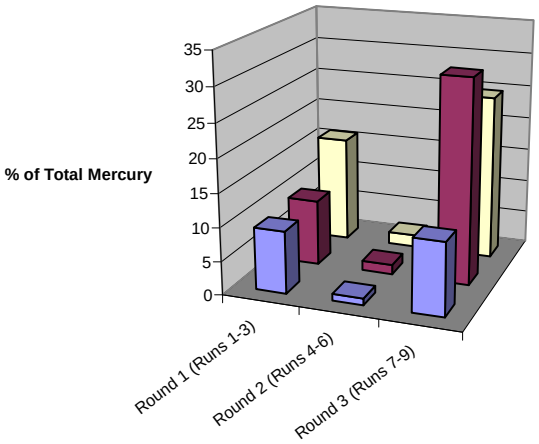
** Gross heat input was stated in the report as being ~170 MW.

Coal Analysis				
Mercury	**Run 1**	**Run 2**	**Run 3**	**Allowable**
ug/kg, dry	0.117	0.127	0.123	---

Attachment D
Percent Particulate-bound Mercury at Massachusetts EGUs

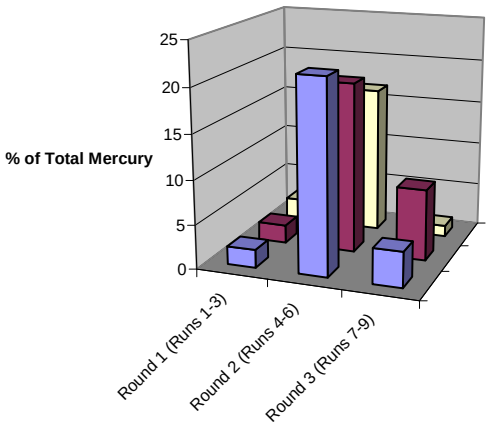
Figures 1-3 present the variations in the percentage of particulate-bound mercury to total mercury measured at three different electric generating units in Massachusetts. The accompanying table to each figure gives the percentage particle-bound mercury relative to total mercury in each sampling run.

Figure 1. Mount Tom Station - Variations in Particle Bound Mercury as a Percent of Total Mercury



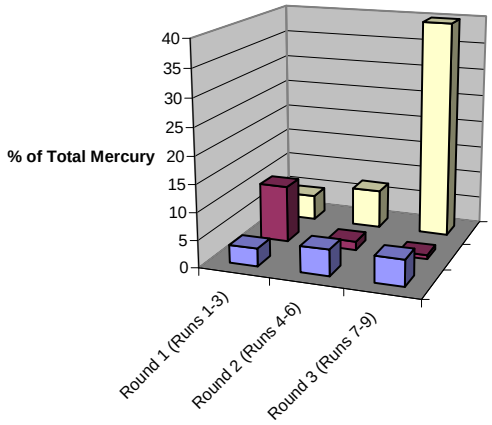
Round 1 (Runs 1-3)	Round 2 (Runs 4-6)	Round 3 (Runs 7-9)
9	1	11
10	1	30
16	2	25

Figure 2. Salem Harbor Station Unit 1 - Variation in Particle Bound Mercury as Percent of Total Mercury



Round 1 (Runs 1-3)	Round 2 (Runs 4-6)	Round 3 (Runs 7-9)
2	22	4
2	19	8
2	17	1

Figure 3. Salem Harbor Station Unit 2 - Variation in Particle Bound Mercury as Percent of Total Mercury



	Round 1 (Runs 1-3)	Round 2 (Runs 4-6)	Round 3 (Runs 7-9)
	3	5	5
	10	2	1
	5	7	40

Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

March 31, 2011

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Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

Prepared For:

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March 31, 2011

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Executive Summary

To implement requirements adopted by Congress in the federal Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) is developing new rules to reduce air pollution from fossil fuel power plants. Power plants that burn coal will bear a large responsibility for reducing their emissions further, as the majority of air pollutants from the electric generation sector come from coal combustion.

The major rules addressing power plant pollution that EPA recently proposed are the Clean Air Transport Rule (Transport Rule), and the National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units (Air Toxics Rule). The Transport Rule will address the long-range interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NOx) in the eastern United States. Both these types of pollutants contribute to formation of small particles ("fine particulates") in the atmosphere that can be transported long distances into downwind states. These small particles can be inhaled deep into the lungs, causing serious adverse health impacts. Nitrogen oxides also contribute to the formation and long-range transport of ground-level ozone, another pollutant with significant health impacts. The Air Toxics Rule will address emissions of hazardous air pollutants (HAPs) such as mercury, lead, arsenic, along with acid gases such as hydrogen chloride and hydrogen fluoride and organic air toxics (e.g., dioxins and furans). HAPs are chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment.

These regulations will require coal-fired power plants that have not yet installed pollution control equipment to do so and, in some cases, will require plants with existing control equipment to improve performance.

Over the last several decades, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. In addition, many states adopted mercury reduction requirements in the absence of federal rules, leading to new controls and significant reductions of this air toxic from a number of coal power plants over the past several years. This has provided industry with a working knowledge of a suite of air pollution control devices and techniques that can comply with EPA's proposed Transport Rule and Air Toxics Rule.

This report provides an overview of well-established, commercially available emission control technologies for SO_2 and NOx, and HAPs, such as mercury, chromium, lead and arsenic; acid gases, such as hydrogen chloride and hydrogen fluoride; dioxins and furans; and other toxic air emissions.

The key findings of the report include:

- **The electric power sector has a range of available technology options as well as experience in their installation and operation that will enable the sector to comply with the Transport Rule and the Air Toxics Rule.**
    - The electric power sector has long and successful experience installing many of the required pollution control systems.

- The first flue gas desulfurization (scrubber) system was installed in 1968 and more than 40 years later, the plant is still in operation and undergoing a performance upgrade.

- To reduce SO_2 emissions, about 60 percent of the nation's coal fleet has already installed scrubber controls, the most capital intensive of the pollution control systems used by coal-fired power plants.

- About half of the nation's coal fleet has already installed advanced post-combustion NOx controls, with the first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. placed in service in 1993 and the first retrofit in the U.S. placed in service in 1995.

- **Modern pollution control systems are capable of dramatically reducing air pollution emissions from coal-fired power plants.**

  - Although scrubbers installed in the 1970s and 1980s typically obtained 80-90 percent SO_2 removal, innovation has led to modern systems now capable of achieving 98 percent or greater removal.

  - SCR can achieve greater than 90 percent NOx removal.

  - Coal-fired power plants, equipped with baghouse systems, report greater than 90 percent removal of mercury and other heavy metals.

- **Pollution controls that significantly reduce mercury emissions from coal-fired power plants have already been installed, demonstrated, and in operation at a significant number of facilities in the United States. This experience demonstrates the feasibility of achieving the mercury emissions limits in the proposed Air Toxics Rule.**

  - In 2001, under cooperative agreements with the Department of Energy, several coal plant operators started full-scale testing of activated carbon injection (ACI) systems for mercury control.

  - Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for coal power plants that require mercury capture rates ranging from 80 to 95 percent. Power plants in a number of these states have already installed and are now successfully operating mercury controls that provide the level of mercury reductions sought in EPA's proposed Air Toxics Rule.

  - At present, about 25 units representing approximately 7,500 MW are using commercial technologies for mercury control. In addition, the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources, has reported about 55,000 MW of new bookings.

- **A wide variety of pollution control technology solutions are available to cost-effectively control air pollution emissions from coal-fired power plants, and many technologies can reduce more than one type of pollutant.**

  - A variety of pollution control solutions are available for different plant configurations.

    - The air pollutants targeted by the Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution controls, and, in many cases, technologies to control one pollutant have the co-benefit of also controlling other pollutants. For example, scrubbers, which are designed to control SO_2, are also effective at controlling particulate matter, mercury, and hydrogen chloride.

    - Dry sorbent injection (DSI) has emerged as a potential control option for smaller, coal-fired generating units seeking to cost-effectively control SO_2 and acid gas emissions.

    - As highlighted below in Table ES-1, because of these "co-benefits," in many cases it may not be necessary to add separate control technologies for some pollutants.

Table ES-1. Control Technology Emission Reduction Effect

	SO_2	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	**N**	**Y**	**C**	**N**	**N**	**Y**
SNCR	**N**	**Y**	**N**	**N**	**N**	**N**
SCR	**N**	**Y**	**C**	**N**	**N**	**C**
Particulate Matter Controls	**N**	**N**	**C**	**N**	**Y**	**C**
Low Sulfur Fuel	**Y**	**C**	**N**	**C**	**N**	**N**
Wet Scrubber	**Y**	**N**	**C**	**Y**	**C**	**N**
Dry Scrubber	**Y**	**N**	**C**	**Y**	**C***	**N**
DSI	**Y**	**C**	**C**	**Y**	**N**	**C**
ACI	**N**	**N**	**Y**	**N**	**N**	**Y**

N = Technology has little or no emission reduction effect
Y = Technology reduces emissions
C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect
* When used in combination with a downstream particulate matter control device, such as a baghouse

- **The electric power sector has a demonstrated ability to install a substantial number of controls in a short period of time, and therefore should be able to comply with the timelines of the proposed EPA air rules.**

  - Between 2001 and 2005, the electric industry successfully installed more than 96 gigawatts (GW) of SCR systems in response to NOx requirements.

  - In response to the Clean Air Interstate Rule (CAIR), about 60 GW of scrubbers and an additional 20 GW of SCR were brought on line from 2008 through 2010. Notably, most companies were "early movers," initiating the installation process before EPA finalized its rules.

- Available technologies that are less resource and time-intensive will provide additional compliance flexibility. For example, DSI and dry scrubbing technology design and installation times are approximately 12 and 24 months, respectively.

- **The electric power sector has access to a skilled workforce to install these proven control technologies.**

- In November 2010, ICAC sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO_2 and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements.

    - Also in November 2010, the Building and Construction Division of the AFL-CIO sent a letter to Senator Carper indicating that "[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development."

    - Actual installation of pollution control equipment far exceeded EPA's earlier estimate of industry capability that it made during the Clean Air Interstate Rule (CAIR) rulemaking.

    - In response to CAIR, boilermakers increased their membership by 35 percent in only two years (between 1999 and 2001) to meet peak labor demand.

In summary, a range of available and proven pollution control technologies exists to meet the requirements of EPA's proposed Transport Rule and Air Toxics Rule. In many cases, these technologies, some of which have been operating for decades, have a long track record of effective performance at many coal-fired power plants in the U.S.

The electric power sector has shown that it is capable of planning for and installing pollution controls on a large portion of the nation's fossil fuel generating capacity in a relatively short period of time. Suppliers have demonstrated the ability to provide pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well. Examples of successful pollution control retrofits are provided throughout this report.

Introduction

The U.S. Environmental Protection Agency (EPA) is currently developing two major air quality rules under the Clean Air Act ("CAA" or "the Act") to reduce air pollution from power plants: (1) the Transport Rule, and (2) the Air Toxics Rule. These regulations will require certain power plants that have not installed pollution control equipment to do so and others to improve their performance. The discussion that follows provides an overview of these regulations, including a discussion of the sources regulated by the rules and the air pollutants the rules address. Both rules are being developed in response to court decisions overturning prior EPA regulatory programs and have long been anticipated by the electric power sector.

Transport Rule

The Transport Rule—proposed by EPA in July 2010—is designed to reduce the interstate transport of harmful air pollution from power plants in the eastern U.S. as required by the CAA. The "good neighbor" provisions of the Act require states to prohibit air pollution emissions that "contribute significantly" to a downwind state's air quality problems.[1] For example, EPA found that power plants in West Virginia significantly affect the air quality status of counties in Ohio, Indiana, Pennsylvania, Kentucky, and Michigan—hindering these states from achieving or maintaining federal air quality standards.[2]

In keeping with the purpose of the "good neighbor" provisions in the Act, the Transport Rule will assist states and cities across the eastern U.S. in complying with the national, health-based fine particulate, or $PM_{2.5}$, and 8-hour ozone standards by limiting SO_2 and NOx emissions from power plants in the region. Fine particulates can be inhaled deep into the lungs, and have been linked to increased hospital admissions and emergency room visits for various respiratory or cardiovascular diseases, respiratory illness and symptoms, lung function changes, and increased risk of premature death. Ground-level ozone is a respiratory irritant that adversely affects both people with respiratory disease and healthy children and adults. Exposure to ozone through inhalation can result in reduced lung function and inflamed airways, aggravating asthma or other lung diseases. As with fine particulate matter, ozone exposure is also linked to increased risk of premature death.

The Transport Rule will replace the earlier Clean Air Interstate Rule (CAIR) that EPA had issued in March 2005.[3] Under CAIR, EPA limited NOx and SO_2 emissions from 28 states and the District of Columbia, and directed each state to file a plan for meeting those limits, or emission caps. In July 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit struck down CAIR after finding several flaws in the rule.[4] In a subsequent ruling, the court determined that CAIR could remain in place until EPA developed a replacement program.[5]

Table 1. The Clean Air Transport Rule

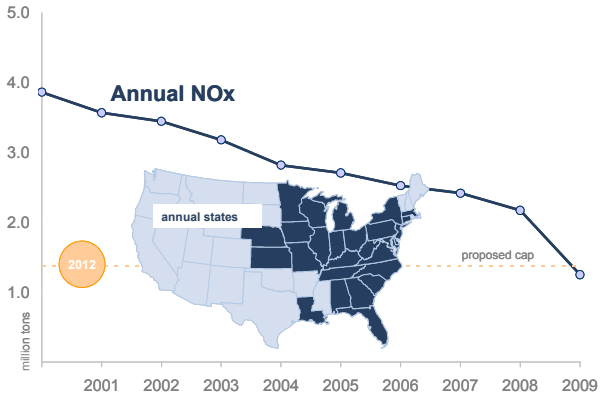
Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Sulfur dioxide (SO_2) Nitrogen oxides (NOx)	Fossil fuel-fired power plants 25 MW and larger in 31 eastern states and DC	Phase 1: 2012 Phase 2: 2014	EPA's preferred approach would allow intrastate trading among covered power plants with some limited interstate trading

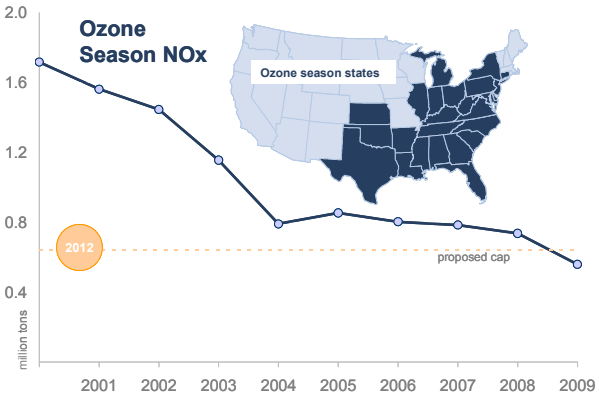
EPA's proposed emissions caps for SO_2 and NOx are summarized in the following figures. EPA notes in the proposed rule that additional ozone season (May 1 to September 30) NOx reductions will likely be needed to attain the national ozone standards.[6] Therefore, the agency plans to propose a new transport rule in 2011, to become final in 2012, to reflect the revised National Ambient Air Quality Standards (NAAQS) for ozone when they are promulgated. While the Transport Rule only proposes to require reductions from the power sector, EPA notes, "it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS."[7]

EPA estimates that the proposed rule would yield $120 billion to $290 billion in annual health and welfare benefits in 2014,[8] which exceed the estimated $2.8 billion in annual costs that EPA estimates power plants will incur to comply with the rule by a factor of more than 30.[9] To meet the new requirements, EPA expects plants will employ a wide range of strategies, including operating already

Clean Air Transport Rule: Proposed NOx Emissions Caps

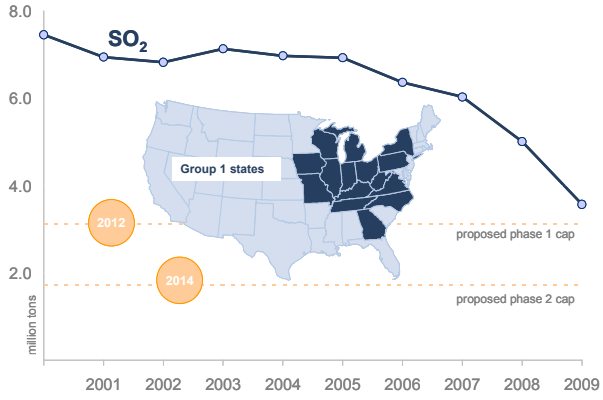
EPA's proposed Transport Rule would establish two NOx programs: (1) an annual NOx program, and (2) an ozone season (summer time) NOx program (see map below). Annual NOx emissions would be capped at 1.4 million tons per year beginning in 2012. The 2012 cap represents a 10 percent increase over 2009 emissions levels. Ozone season NOx emissions would be capped at 0.6 million tons beginning in 2012. The ozone season cap represents a 15 percent increase over 2009 emissions levels.

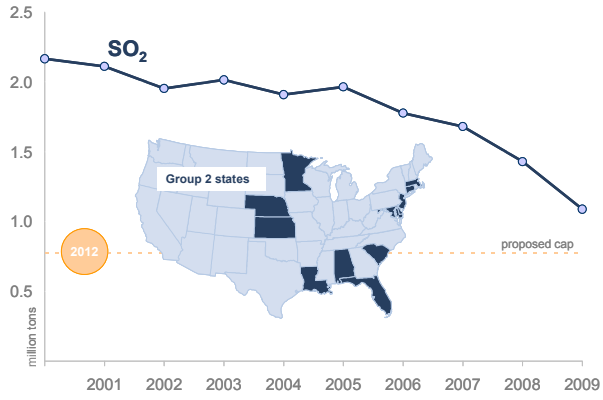




Clean Air Transport Rule: Proposed SO_2 Emissions Caps

EPA's proposed Transport Rule would establish two independent trading programs for SO_2: (1) group 1 states; and (2) group 2 states (see maps below). SO_2 emissions from group 1 states would be capped at 3.1 million tons per year beginning in 2012 and 1.7 million tons per year beginning in 2014. The 2012 cap represents a 13 percent reduction below 2009 emissions levels. SO_2 emissions from group 2 states would be capped at 0.8 million tons beginning in 2012. The 2012 cap for group 2 states represents a 29 percent reduction below 2009 emissions levels.





installed pollution control equipment more frequently, using low sulfur coal, or installing new control equipment.

Air Toxics Rule

The U.S. EPA's proposed Air Toxics Rule will establish, for the first time, federal limits on hazardous air pollutant (HAP) emissions from coal- and oil-fired power plants. The HAPs covered include mercury, lead, arsenic, hydrogen chloride, hydrogen fluoride, dioxins/furans, and other toxic substances identified by Congress in the 1990 amendments of the CAA. The rule establishes "maximum achievable control technology" (MACT) limits for many of these.

The U.S. EPA's prior effort to regulate HAP emissions from power plants was overturned by court challenges. On February 8, 2008, a federal court held that EPA violated the CAA when it sought to regulate mercury-emitting power plants through the Clean Air Mercury Rule (CAMR), an interstate cap-and-trade program issued by EPA in March 2005.[10] The court concluded that EPA violated the CAA by failing to make a specific health-based finding to remove electric generating units from regulation under CAA section 112.[a]

On March 16, 2011, EPA proposed its replacement for CAMR that would establish numerical MACT emission limits for existing and new coal-fired electric power plants that would cover mercury, particulate matter (as the surrogate for non-mercury toxic metals), and hydrogen chloride (as the surrogate for toxic acid gases). The proposed rule would also establish work practice standards for organic air toxics (e.g., dioxins and furans).[11] EPA projects the proposed rule will reduce mercury emissions from covered power plants by 91 percent, acid gas emissions by 91 percent, and SO_2 emissions by 55 percent.[12] The projected mercury reductions are in the range of what a number of states already require for coal-fired power plants.[13] A consent decree with public health and environmental groups requires EPA to finalize the standards by November 16, 2011. Table 2 summarizes elements of the proposed Air Toxics Rule.

EPA estimates that the Air Toxics Rule would yield $140 billion in annual health and welfare benefits in 2016.[14] The estimated annual cost of the program is $10.9 billion.[15] EPA emphasizes that the proposed rule would cut emissions of pollutants that are of particular concern for children. Mercury and lead can adversely affect developing brains–including effects on IQ, learning, and memory.

Table 2. The Air Toxics Rule

Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Mercury Non-mercury metals, such as arsenic, chromium, cadmium, and nickel Organic HAPs (e.g., dioxins/furans) Acid gases (HCl, HF)	Coal- and oil-fired power plants 25 MW and larger	Early 2015 **Note:** EPA can grant a one year extension for a source to install controls	Numerical emission limits for mercury, other toxic metals, and acid gases; work practice standards for organic air toxics (e.g., dioxins/furans)

[a] "*EPA's removal of these [electric generating units] from the section 112 list violates the CAA because section 112(c)(9) requires EPA to make specific findings before removing a source listed under section 112; EPA concedes it never made such findings. Because coal-fired [electric generating units] are listed sources under section 112, regulation of existing coal-fired [electric generating units'] mercury emissions under section 111 is prohibited, effectively invalidating CAMR's regulatory approach." New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).*

Overview of Air Pollution Control Technologies

There are a wide range of technologies available for controlling air pollution emissions from coal-fired power plants. The most appropriate combination of control technologies will vary from plant-to-plant depending on the type and size of the electric generating unit, age, fuel characteristics, and the boiler design.

Many of the air pollutants targeted by the proposed Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution control devices. Table 3 summarizes the various pollutants and the technologies that are currently being applied or may be applied in the future to control them. In many cases, technologies designed to control one pollutant will also control others. These "co-benefits" may or may not be adequate to achieve compliance with the Transport Rule or the Air Toxics Rule. As a result, in some cases, it may be necessary to add separate control technologies for some pollutants.

Table 3. Control Technology Emission Reduction Effect

	SO_2	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
Selective Non-Catalytic Reduction (SNCR)	N	Y	N	N	N	N
Selective Catalytic Reduction (SCR)	N	Y	C	N	N	C
Particulate Matter Controls (i.e., ESP or baghouse)	N	N	C	N	Y	C
Lower Sulfur Fuel	Y	C	N	C	N	N
Dry Scrubber	Y	N	C	Y	C*	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Sorbent Injection (DSI)	Y	C	C	Y	N	C
Activated Carbon Injection (ACI)	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect
Y = Technology reduces emissions
C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect
* When used in combination with a downstream particulate matter control device, such as a baghouse

Methods for Controlling SO_2 Emissions

SO_2 is a highly reactive gas linked to a number of adverse effects on the human respiratory system. In 2008, power plants accounted for 66 percent of the national SO_2 emissions inventory,[16] with the vast majority of this contribution (more than 98 percent) coming from coal-fired power plants.[17]

There are two basic options for controlling SO_2 emissions from coal-fired power plants, which is formed from the oxidation of sulfur in the fuel: (1) switching to lower sulfur fuels; and (2) SO_2 capture, including Flue Gas Desulfurization (FGD), or more commonly referred to as "scrubbing." Table 4 shows the various methods for controlling SO_2 emissions. These methods include those that have been widely used on power plants, such as low sulfur coal and scrubbing, as well as less costly technologies that may be more attractive for smaller boilers, such as dry sorbent injection (DSI).

Table 4. SO_2 Emissions Control Methods	
Methods of Control	
Lower Sulfur Fuel	Method – Lower sulfur fuel reduces SO_2 formation Reagent – None Typical fuel types – Powder River Basin coal and lower sulfur bituminous coal Capital Cost – Low Co-benefits – May reduce NOx, HCl, and HF emissions
Dry Sorbent Injection	Method – Dry Sorbent Injection captures SO_2 at moderate rates, downstream PM control device captures dry product Reagent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels (i.e., coals – lignite, sub-bituminous, bituminous) Capital Costs- Low to moderate Co-benefits – NOx and HCl and HF reduction, Hg reduction, removal of chlorine, a precursor to dioxins/furans
Dry Scrubber with Fabric Filter	Method – Reagent + water react to capture acid gases and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Coal Capital Costs – High Co-benefits – High SO_2 and Hg capture (esp. bituminous coals), high PM and HCl capture
Wet Scrubber	Method – Reagent + water react to capture acid gases Reagent – Limestone, lime, caustic soda Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – High Co-benefits –Highest SO_2 capture, high oxidized Hg and high HCl capture, PM capture
Wet Scrubber Upgrades	Method – Upgrade older scrubbers to provide performance approaching those of new scrubbers Reagent – Limestone, lime, etc. Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – Low to moderate Co-benefits – Same as wet scrubber
Co-benefit Methods of Control	
None	SO_2 is a key pollutant that often is the major driver in emission control technology selection

Lower Sulfur Coal

Changing to lower sulfur coal was the most widely used approach for compliance with the Acid Rain Program (Title IV of the 1990 Clean Air Act Amendments). Certain coal types are naturally low in sulfur, such as sub-bituminous coal mined in the Powder River Basin (PRB) of Montana and Wyoming.[b]

Some facilities cannot burn 100 percent PRB coal without substantial modifications to the boiler or fuel handling systems. These facilities can blend PRB or another lower sulfur coal with a bituminous coal to reduce emissions. Facilities that are not able to burn lower sulfur coals or facilities needing greater SO_2 emissions reductions may need some form of flue gas treatment.

[b] Coal is classified into four general categories, or "ranks." They range from lignite through sub-bituminous and bituminous to anthracite. Sub-bituminous and bituminous coals are the most widely used coal types, and the SO_2 emissions from burning these fuels can vary by a factor of 10 or more, depending upon the fuel sulfur content and the heating value of the fuel. Lignite fuels have low heating values, making them uneconomical to transport, and are generally limited in use to mine-mouth plants. Anthracite coal is used in very few power plants.

Co-benefits of low sulfur coal – PRB coal is relatively low in nitrogen, which results in lower NOx emissions. It is also very low in chlorine, so hydrogen chloride (HCl) emissions are low for PRB coal.

Flue Gas Desulfurization (FGD) or "Scrubbing"

As EPA and states have further limited SO_2 emissions, an increasing number of coal-fired power plants have installed FGD systems. FGD controls enable a plant operator to use a wider variety of coals while maintaining low SO_2 emissions. There are two basic forms of FGD – wet and dry. As shown in Table 5, nearly two-thirds of the coal-fired power plant capacity in the United States is scrubbed or is projected to be scrubbed in the near future. Most plant operators have opted for wet FGD systems, particularly on larger coal-fired power plants. In response to the Clean Air Interstate Rule, coal-fired power plants added about 60 gigawatts (GW) of scrubbers in the three year period from 2008 through 2010.[18]

Table 5. Coal-Fired Power Plant Scrubbers[19]

Scrubber Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
FGD (wet)	170 GW (52%)	371	457
FGD (dry)	22 GW (7%)	114	196
Total Scrubbed	**192 GW (59%)**	**485**	**396**
No scrubber	134 GW (41%)	788	171
Total	**326 GW**	**1,273**	**256**

Wet Scrubbers

Wet scrubbers are capable of high rates of SO_2 removal. In a wet FGD system, a lime or limestone slurry reacts with the SO_2 in the flue gas within a large absorber vessel to capture the SO_2, as shown in Figure 1.[20] Wet FGD systems may use lime or limestone. Lime is more reactive and offers the potential for higher reductions with somewhat lower capital cost; however, lime is also the more expensive reagent. As a result, limestone-forced oxidation (LSFO) wet scrubber technology is the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more.

The first wet scrubber system in the U.S. was designed by Black & Veatch and installed in 1968 at the Lawrence Energy Center in Kansas. More than 40 years later, the system is still in operation, and the facility is undertaking a major upgrade to improve the system's performance. The facility is also adding a pulse jet fabric filter.[21]

In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas and high rates of capture. Modern wet scrubbers typically have SO_2 removal rates of over 95 percent and can be in the range of 98 percent to 99 percent.[22] The reacted

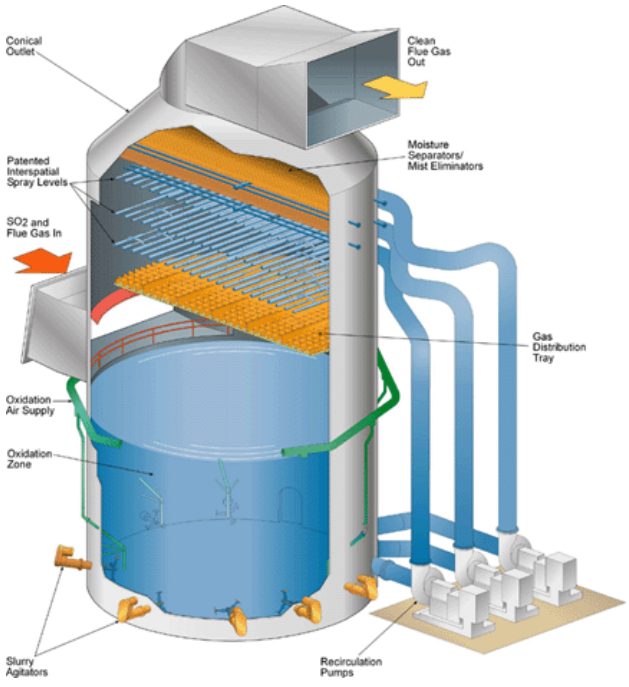


Figure 1. Wet Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

limestone and SO_2 form a gypsum by-product that is often sold for the manufacturing of wallboard.

Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an electrostatic precipitator though many power plants have baghouses) and immediately upstream of the stack. Wet FGD is frequently used to treat the exhaust gas of multiple boilers with the gases being emitted through a common stack. A single absorber can handle the equivalent of 1,000 megawatts (MW) of flue gas.

Wet scrubber retrofits are capital intensive due to the amount of equipment needed, and recent installations for the Clean Air Interstate Rule have been reported to have an average cost of $390/kW.[23] EPA estimates a capital cost of about $500/kW ($2007) for a wet scrubber (limestone forced oxidation) on a 500 MW coal unit.[24] There can be, however, a significant variation in costs depending upon the size of the unit and the specifics of the site. Generally, smaller boilers (under 300 MW) have been shown to be significantly more expensive to retrofit with wet scrubbers (capital cost normalized to a $/KW basis) than larger boilers due to economies of scale. The economies of scale become less significant as boiler size increases.[25] As a result, wet scrubbers are a less attractive alternative for controlling SO_2 on small units. Companies can sometimes offset the cost of installing wet scrubber technology by switching to less expensive high sulfur coal supplies. Because of the high capital costs of the technology, wet scrubbers are generally only installed on power plants where the owner expects to operate the plant for an extended number of years.

Due to their complexity and the size of the equipment, EPA estimates that the total time needed to complete the design, installation, and testing of a wet FGD system at a typical 500 MW power plant with one FGD unit is 27 months, and longer if multiple boilers or multiple absorbers are necessary. Actual installation times will vary based upon the specifics of the plant, the need to schedule outages with FGD hook up, and other factors.

Co-benefits of wet FGD – FGDs have been shown to be effective at removing other pollutants including particulate matter, mercury, and hydrochloric acid. For this reason, facilities that are equipped with wet or dry FGD systems may avoid the need to install additional controls for hazardous air pollutants.

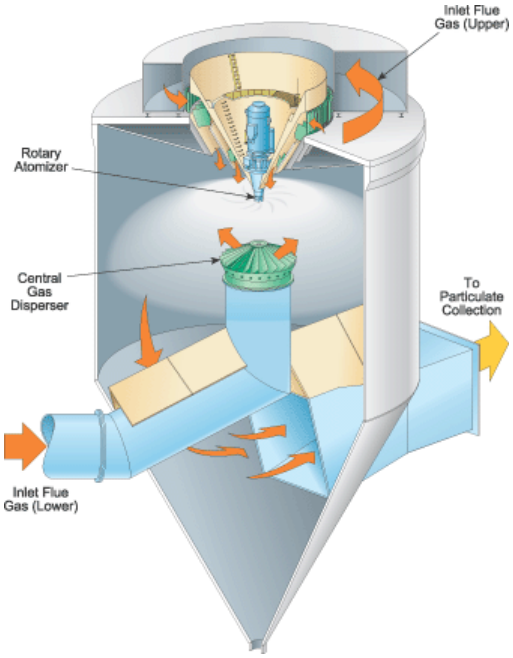


Figure 2. Dry Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

Dry Scrubbers

Dry scrubber technology (dry FGD) injects hydrated lime and water (either separately or together as a slurry) into a large vessel to react with the SO_2 in the flue gas. Figure 2 shows a schematic of a dry scrubber.

The term "dry" refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the dry FGD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO_2. Modern dry FGD systems typically provide SO_2 capture rates of 90 percent or more.

Historically, dry FGDs have been used primarily on low sulfur coals because the reagent, lime, is more expensive than reagents used in wet FGD systems. Also, because the systems are designed to maintain the flue gas temperatures above the dew point, this limits the amount of SO_2 that can be treated by a spray dryer. Another form of dry FGD, circulating dry scrubber systems (CDS), inject the water and lime separately, and have been shown to achieve high SO_2 removal rates in excess of 95 percent on higher sulfur coals. Lime is more costly than limestone, the most commonly used reagent for wet scrubber systems.

Case Study: Dry Scrubber

In Massachusetts, First Light's Mt. Tom Power Plant, a 146 MW coal-fired unit that went into service in 1960, installed state-of-the-art pollution control equipment in 2009 to meet state and federal environmental regulations. In December 2009, the plant installed a circulating dry scrubber to reduce SO_2 and mercury emissions during a routine outage. A precipitator and baghouse were also installed to remove particulate matter emissions. Total project costs were $55 million, or $377/kW. The project has reduced the plant's SO_2 emissions by approximately 70 percent, with the plant's 2009 SO_2 emission rate of 0.73 lbs SO_2/mmBtu dropping to 0.22 lbs SO_2/mmBtu in 2010.

Source: U.S. Environmental Protection Agency, Clean Air Markets-Data and Maps; http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard (accessed March 17, 2011).

Dry FGD systems tend to be less expensive than wet FGD systems because they are less complex and generally smaller in size. They also use less water. The lower reagent cost of wet FGD and the ability to burn lower cost, higher sulfur coals make wet FGD more attractive for large facilities. EPA estimates a capital cost of about $420/kW ($2007) for a dry scrubber (lime spray dryer) on a 500 MW coal unit.[26] The Turbosorp system installed at the AES Greenidge plant in New York cost $229/KW ($2005).[27] Depending upon the specifics of the facility to be retrofit, the cost could be higher in some cases.

Dry FGD systems are less complex and generally require less time to design and install than wet FGD systems. The Institute to Clean Air Companies (ICAC) estimates that dry scrubbers can be installed in a time frame of 24 months.[28]

Co-benefits of Dry FGD – Dry FGD pollutant co-benefits include greatly enhanced capture of hazardous air pollutants, especially PM, mercury and HCl (as discussed later in the report).

Upgrades to Existing Wet FGD Systems

Modern wet FGD systems are capable of SO_2 removal rates in the range of 98 percent or more. Limestone wet scrubber removal efficiencies have improved dramatically since the 1970s as shown in Figure 3.[29] As a result, there are opportunities to improve scrubber performance from many existing scrubbers that were built in the 1970s and 1980s. An advantage of this approach is that substantial SO_2 reductions are possible at a far lower cost than installing a new scrubber and in a much shorter period of time. Each scrubber upgrade is unique, so cost and schedule will vary. Depending upon the scope of a scrubber upgrade, a scrubber upgrade could be implemented in under a year as opposed to three to four years for a new scrubber installation. All key areas of many older FGD systems (absorber, reagent preparation, and dewatering) can benefit from modern upgrades. Because each system is unique, an

effective FGD system-wide upgrade process is most successful after an extensive system review and diagnostics.

There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent.[30] In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency.[31] In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009.[32] The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.[33]

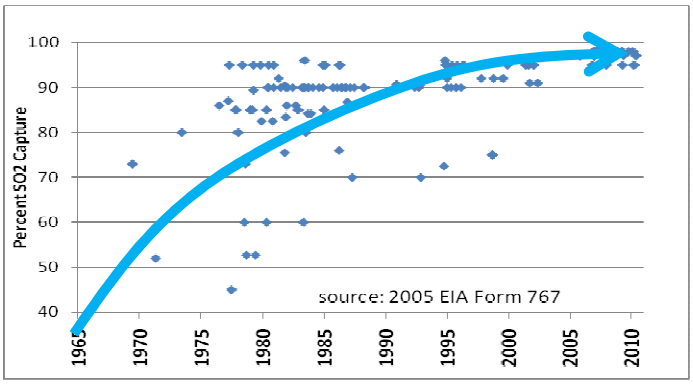


Figure 3. Historical Trends in Limestone Wet Scrubber SO_2 Removal Efficiency of Limestone Wet Scrubbing Systems

Dry Sorbent Injection (DSI)

DSI is the injection of dry sorbent reagents that react with SO_2 and other acid gases, with a downstream PM control device to capture the reaction products.

The most common DSI reagent in use is Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states. Other reagents have also been used, such as sodium bicarbonate and hydrated lime. Sodium bicarbonate is capable of higher SO_2 removal efficiencies than Trona because it is more reactive. Trona can achieve varying levels of SO_2 reductions, from a range of 30-60 percent when injected upstream of an ESP, or up to 90 percent when injected upstream of a fabric filter. Fabric filters allow greater contact between the gas and the injected sorbent than ESPs, enabling better removal for any given reagent treatment rate. The level of removal will vary depending upon the circumstances of the facility and the injection system.

DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.[34] Unlike scrubbers that require additional reaction chambers to be installed, in DSI the reaction occurs in the existing ductwork and air pollution control equipment. The basic injection system with storage silo costs around $20/kW; however, in some cases additional storage and material handling may be necessary that will add cost. But, even with the additional equipment, the capital cost of a DSI system will be substantially less than that of a full wet or dry scrubber, which can cost as high as $400/kW. Reagents used in DSI are more costly than those used in wet or dry scrubbers, and the reagent is not as efficiently utilized, which can contribute to a higher cost of control in terms of dollars per ton of SO_2 reduced.

Case Study: Dry Sorbent Injection

Conectiv Energy installed a DSI Trona system at Edge Moor Units 3-4 to comply with Delaware's multi-pollutant emissions control rule. The project was several years in planning and operated from 2009 to mid-2010. The emission rates went from 1.2 lbs SO_2/mmBtu to 0.37 lbs SO_2/mmBtu with the use of Trona. Since the purchase of the facility by Calpine in mid-2010, coal is no longer burned thus eliminating the need for the Trona system. In New York, NRG installed a Trona system at its Dunkirk (530 MW) and Huntley stations (380 MW). This project is the first of its kind in the U.S. in which Trona and powder-activated carbon (PAC) are simultaneously injected into the flue gases to control both SO_2 and mercury emissions. The DSI system included several Trona storage and injection systems with equipment buildings, 6000 feet of transport piping, Trona railcar unloading and transfer systems, and associated bulk storage silos. Performance tests indicate that emissions of SO_2 have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/mmBtu.

Source: Pietro, J. and Streit, G. (NRG Energy). "NRG Dunkirk and Huntley Environmental Retrofit Project." Presented to Air & Waste Management Association – Niagara Frontier Section, September 23, 2010.

Co-benefits of DSI – DSI has been shown to be very effective in the capture of the acid gases, HCl and HF. DSI has been shown to enhance mercury capture for facilities that burn bituminous coal by removing sulfur trioxide (SO_3) that is detrimental to mercury capture through ACI. In the case of PRB coals, the impact on mercury capture might be negative. Injection of Trona or sodium bicarbonate can also remove NOx in the range of 10-20 percent, although NOx removal is generally not a principal objective of DSI.[35] If DSI is installed at a point in the gas stream that is upstream of the dioxins/furans formation temperature, it is expected to remove the precursor chlorine that leads to their production.

Methods for Controlling NOx Emissions

Nitrogen oxides (NOx) are an acid rain precursor and a contributor to the formation of ground-level ozone, which is a major component of smog. In 2008, power plants accounted for 18 percent of the national NOx emissions inventory. Most of the NOx formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NOx; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NOx. Controlling NOx emissions is achieved by controlling the formation of NOx through combustion controls or by reducing NOx after it has formed through post-combustion controls. Table 6 summarizes key NOx control technologies.

Table 6. NOx Emissions Control Methods	
Methods of Control	
Combustion Controls	Method – Reduce NOx formation in the combustion process itself for levels of reduction that vary by application Reagent – None Typical fuel types – All fuels Capital Cost – Low to moderate Co-benefits – Potential impacts on Hg, CO and precursors of dioxins/furans
Selective Non-Catalytic Reduction	Method – Reagent injected into furnace reacts with and reduces NOx at moderate removal rates of about 30% Regent – Urea or ammonia Typical Fuel Types – Most often solid or liquid fuels Capital Costs- Low Co-benefits - None
Selective Catalytic Reduction	Method – Reagent reacts with NOx across catalyst bed and reduces NOx at high rates of about 90% Reagent – Ammonia (or urea that is converted to ammonia) Typical Fuel Types – Any fuel Capital Costs – High Co-benefits – Oxidation of Hg for easier downstream capture in a wet scrubber, reduction of dioxins/furans
Co-benefit Methods of Control	
Low Sulfur Coal	Conversion to PRB coal for SO_2 reduction will also reduce NOx due to lower fuel nitrogen in PRB coal
Dry Sorbent Injection	DSI with Trona can provide NOx reduction of about 10-15%

Combustion Controls

Combustion controls minimize the formation of NOx within the furnace and are frequently the first choice for NOx control because they are usually lower in cost than post-combustion controls. For most forms of combustion control, once installed there is little ongoing cost because there are no reagents or catalysts to purchase. Combustion controls reside within the furnace itself, not in the exhaust gas stream, and include such methods as low NOx burners (LNB), over-fire air (OFA), and separated over-fire air (SOFA). Reburning technology is another combustion control option, but it chemically reduces NOx formed in the primary combustion zone. Reburning technology may also utilize natural gas.

Most utilities have already achieved substantial reductions in NOx emissions from implementation of combustion controls, sometimes in combination with post-combustion controls. There are some facilities that can still benefit from combustion controls, but these are generally the smaller units where utilities have not yet invested in NOx controls.

The capital cost of these combustion controls will vary; however, the capital cost is generally far less than that of more costly post-combustion control options, such as Selective Catalytic Reduction (SCR). The capital costs of combustion controls could be anywhere from about $10/kW to several times that, but generally fall below $50/kW. Except for gas reburning, there is little or no increase in operating or fuel costs.

Co-benefits of Combustion NOx Controls – Combustion controls may enhance mercury capture at coal-fired power plants because they can increase the level of carbon in the fly ash. While higher carbon in the

fly ash is generally viewed negatively because it is the result of incomplete combustion, it does provide a real benefit in enhancing mercury capture. Combustion controls can also have a positive impact on CO emissions and on concentrations of organic precursors to dioxins/furans.

Post-Combustion NOx Controls

There are limits to the level of NOx control that can be achieved with combustion controls alone. Therefore, post-combustion controls are necessary to achieve very low emissions of NOx. Combustion NOx controls and post-combustion NOx controls can, and often are, used in combination. About half of the nation's coal fleet has already installed advanced post-combustion NOx controls (Table 7).

Table 7. Coal-Fired Power Plant Post-Combustion NOx Controls[36]

Control Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
SCR	129 GW (40%)	259	499
SNCR	29 GW (9%)	172	166
Total Post-Combustion NOx	**158 GW (49%)**	**431**	**366**
No Post-Combustion NOx	842 GW (51%)	842	198
Total	**324 GW**	**1,273**	**255**

Selective Catalytic Reduction (SCR)

SCR technology, which has been in use at coal-fired power plants for more than 15 years in the United States, is a post-combustion NOx control system that is capable of achieving greater than 90 percent removal efficiency.[37] The first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. was placed in service in 1993 in New Jersey, and the first retrofit in the U.S. went into service in 1995 at a power plant in New Hampshire.[38] About 130 GW of the total coal-fired generating capacity in the U.S. is now equipped with SCR, and more SCRs are planned for existing units. Between 2001 and 2005, the electric industry installed more than 96 GW of SCR systems in response to the NOx SIP Call. Coal plant operators installed an additional 20 GW of SCR from 2008 through 2010 in response to the Clean Air Interstate Rule.[39]

SCR utilizes ammonia as a reagent that reacts with NOx on the surface of a catalyst. The SCR catalyst reactor is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler. The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency (Figure 4).

SCR system capital costs will vary over a wide range depending upon the difficulty of the retrofit. Some retrofits have been reported to cost under $100/kW, while others have been reported to cost over $200/kW.[40] Operating costs include ammonia reagent, periodic catalyst replacement, parasitic power, and fixed operating costs.

The EPA estimates that the total time needed to complete the design, installation, and testing at a facility with one SCR unit is about 21 months, and longer for plants that have multiple units to be retrofitted with SCR.[41]

Selective Non-Catalytic Reduction (SNCR)

SNCR is another post-combustion NOx control technology. It typically achieves in the range of 25-30 percent NOx reduction on units equipped with low NOx burners. SNCR reduces NOx by reacting urea or ammonia with the NOx at temperatures around 1,800°F-2,000°F. Therefore, the urea or ammonia is injected into the furnace post-combustion zone itself and, like SCR, reduces the NOx to nitrogen and water.

The capital cost of SNCR is typically much less than that of SCR, falling in the range of about $10-$20/KW, or about $4 million or less for a 200 MW plant. The operating cost of SNCR is primarily the cost of the ammonia or urea reagent. SNCR is most commonly applied to smaller boilers. This is partly because the economics of SCR are more challenging for small boilers. Furthermore, when emissions regulations allow averaging or trading of NOx emissions among units under a common cap, installing an SCR on a large boiler allows utilities to over-control the large unit and use less costly technology, such as SNCR or combustion controls, for NOx control on smaller units.

SNCR systems are relatively simple systems that can be installed in a period of about 12 months.

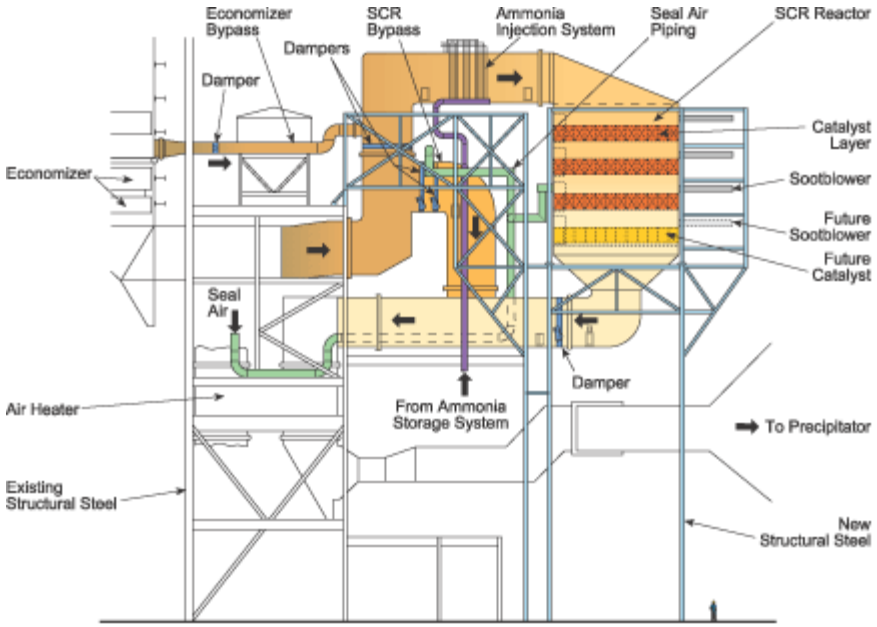


Figure 4. Selective Catalytic Reduction (Retrofit Installation)
Image courtesy of Babcock and Wilcox Company

Hybrid SNCR/SCR

SNCR and SCR may be combined in a "hybrid" manner. In this case, a small layer of catalyst is installed in ductwork downstream of the SNCR system. With the downstream catalyst, the SNCR system can be operated in a manner that provides higher NOx removal rates while using the SCR catalyst to mitigate the undesirable ammonia slip from the SNCR system. Although some NOx reduction occurs across the SCR catalyst, its function is primarily as a means to reduce ammonia slip to an acceptable level. This approach has been demonstrated at the Greenidge power plant in upstate New York, but has not been widely adopted.[42] For some smaller boilers that can accommodate the needed ductwork modifications necessary for "hybrid" SNCR/SCR, this may be an attractive technology for reducing NOx emissions beyond what SNCR is able to achieve.

The hybrid SNCR/SCR system installed at Greenidge was part of a multi-pollutant control system designed to demonstrate a combination of controls that could meet strict emissions standards at smaller coal-fired power plants.[43] The multi-pollutant control system was installed on AES Greenidge Unit 4, a 107 MW, 1953-vintage tangentially-fired boiler. The facility fires high sulfur eastern U.S. bituminous coal. The multi-pollutant control system consists of a hybrid SNCR/SCR technology to control NOx, a circulating fluidized bed dry scrubbing technology to control SO_2, mercury, SO_3, hydrogen chloride, and

particulate matter, and an activated carbon injection system to control mercury emissions. Total capital cost of the system was $349/kW (2005$), about 40 percent less than the estimated cost of full SCR and wet scrubbers—$114/kW for the hybrid SNCR/SCR system, $229/kW for the circulating dry scrubber system and $6/kW for the activated carbon injection system. The plant has achieved 95 percent SO_2 control, 98 percent mercury removal, and 95 percent SO_3 and HCl removal.[44]

Co-benefits of post-combustion NOx controls – SNCR has no known co-benefit effects on other pollutants. SCR, on the other hand, has the co-benefit effect of enhancing oxidation of elemental mercury, especially for bituminous coals. The effect of mercury oxidation is to enhance mercury capture in a downstream wet FGD because the resulting ionic mercury is extremely water soluble. Several field and pilot studies conducted in the U.S. have found increases in oxidized ionic mercury with the use of SCR controls.[45,46,47,48] For example, testing conducted at the Mount Storm coal-fired power plant in West Virginia evaluated the effect of the unit's SCR system on mercury speciation and capture.[49] The facility fires a medium sulfur bituminous coal. The test program found that the presence of an SCR catalyst can significantly affect the mercury speciation profile. Measurements showed that the SCR catalyst improved the mercury oxidation to levels greater than 95 percent, almost all of which was captured by the downstream wet FGD system. In the absence of the SCR catalyst, the extent of oxidation at the inlet of the FGD system was only about 64 percent. This effect, however, is much reduced with PRB coals because halogen content in PRB coals is low. SCR catalyst can also mitigate emissions of dioxins and furans.[50,51]

Methods for Controlling Hazardous Air Pollutant Emissions

HAPs from power plants include mercury, acid gases (HCl and HF), heavy metals (nickel, chromium, arsenic, selenium, cadmium, and others), and organic HAPs (dioxins and furans). Many HAPs emitted by power plants are captured to some degree by existing air pollution control technologies. However, EPA's proposed Air Toxics Rule will establish emissions standards that will require additional controls be installed. For each of these HAPs, the potential methods for capture are discussed below.

Control of Mercury Emissions

Mercury is found within coal, with its concentration varying widely by coal type and even within coal types. The mercury is released during combustion and becomes entrained in a power plant's flue gas in one of three forms; particle-bound mercury, gaseous elemental mercury, and gaseous ionic mercury. Table 8 lists available methods to control mercury emissions for coal units.

Table 8. Mercury Emissions Control Methods	
Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous Hg, converting to particle Hg that is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Some capture of dioxins/furans
Halogen Addition	Method – Halogen (bromine) addition to flue gas increases oxidized Hg that is easier to capture in a downstream scrubber or in PM control device Reagent – Halogen containing additive Capital Costs – Negligible Co-benefits – None
Co-benefit Methods of Control	
PM Controls (ESP, FF, multicyclone)	Method – Captures particle-bound mercury
Dry Sorbent Injection	Method – Increases co-benefit and ACI Hg capture by removing SO_3, which suppresses mercury capture
Dry Scrubber with Fabric Filter	Method – Hg captured in downstream fabric filter
Wet Scrubber	Method – Oxidized mercury captured in wet scrubber
NOx Catalyst	Method – Catalyst in SCR increases oxidation of Hg that is more effectively captured in downstream wet scrubber

Activated Carbon Injection (ACI)

Mercury is often captured using injection of powdered activated carbon (activated carbon injection – ACI) and capture of the injected carbon on a downstream PM capture device (ESP or a baghouse). An ACI system is relatively simple and inexpensive, consisting of storage equipment, pneumatic conveying system, and injection hardware ("injection lances"). Under cooperative agreements with the U.S. Department of Energy, several coal plant operators conducted full-scale testing of ACI systems in 2001.[52]

ACI has been used to capture mercury by effectively converting some of the gaseous ionic and elemental mercury to a particle-bound mercury that is captured in a downstream particulate matter control device, such as an ESP or fabric filter. ACI is very effective at removing mercury except if high sulfur coals are used, or if SO_3 is injected for flue gas conditioning for ESPs, or if the facility has a hot-side ESP and no downstream air pollution controls. SO_3 interferes with mercury capture by ACI; however, upstream capture of SO_3 by DSI, if one is in place, should enable ACI to be more effective at capturing mercury. Fortunately, most of the installed capacity of boilers firing high sulfur fuels is scrubbed and may not need ACI.

Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for power plants that require mercury capture rates ranging from 80 to 95 percent.[53] At present, about 25 units representing about 7,500 MW are using commercial ACI technologies for mercury control. In addition, about 55,000 MW of new bookings are reported by the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources.[54]

ACI systems cost in the range of $5/kW and can be installed in about 12 months or less, assuming a baghouse is installed. PSEG's Bridgeport Harbor Generating Station completed the construction and

installation of a baghouse and ACI system in under 2 years. The final connection of the controls was completed during a six to eight week outage.

Case Study: ACI Controls

In response to a 2006 Minnesota state mercury law, Xcel Energy agreed to install an ACI system on the 900 MW Unit 3 at its Sherburne County plant (Sherco 3). The unit, which burns low sulfur western coal from Montana and Wyoming, already had a dry scrubber operating to reduce SO_2 emissions. Once it has been tuned to the unit's operational specifications, the ACI system is expected to reduce the plant's mercury emissions by about 90 percent. The system was completed in December 2009 for a total capital cost of $3.1 million, or $3.46/kW. Wisconsin Power and Light installed ACI controls at its Edgewater Generating Station. The system was operational in the first quarter of 2008. Edgewater Unit 5 is a 380 MW plant that fires PRB coal and is configured with a cold-side ESP for particulate control. The total installed costs of the Edgewater Unit 5 ACI system was approximately $8/kW, or approximately $3.04 million.

Source: Southern Minnesota Municipal Power Agency. "Sherco 3: Environmental Controls." August 2010, http://www.smmpa.com/upload/Sherco%203%20brochure%202010.pdf (accessed March 17, 2011).

Starns, T., Martin, C., Mooney, J., and Jaeckels, J. "Commercial Operating Experience on an Activated Carbon Injection System, Paper #08-A-170-Mega-AWMA." Power Plant Air Pollutant Control MEGA Symposium. Baltimore, MD. August 25-28, 2008.

Co-benefits of ACI – ACI co-benefits include the reduction of dioxins and furans.

Halogen Addition

For applications where there is inadequate halogen for conversion of elemental mercury to ionic mercury, such as some western coals, the addition of halogen will increase mercury conversion to the ionic form and will permit higher capture efficiency through co-benefit capture or by ACI. Addition of halogen to PRB coals or to activated carbon injected for mercury capture has been shown to make mercury capture from PRB fired boilers with halogen addition generally high.[55]

Co-Benefit Methods for Mercury Capture

Of the three mercury forms previously mentioned, particle-bound mercury is the species more readily captured as a co-benefit in existing emission control devices, such as fabric filters (also called "baghouses") or electrostatic precipitators (ESPs). Ionic mercury has the advantage that it is extremely water soluble and is relatively easy to capture in a wet FGD/scrubber. Ionic mercury is also prone to adsorption onto fly ash or other material, and may thereby become particle-bound mercury that is captured by an ESP or fabric filter. Elemental mercury is less water soluble and less prone to adsorption, thus remains in the vapor phase where it is not typically captured by control devices unless first converted to another form of mercury more readily captured.

Fabric filters generally provide much higher co-benefit mercury capture than ESPs. Bituminous coal-fired boilers with fabric filters can have high rates of mercury capture based on data collected by the U.S. EPA during its Information Collection Request (ICR) supporting the development of the Air Toxics Rule.[56]

Wet scrubbers with SCR controls upstream have been shown to be very effective in removing oxidized (ionic) mercury. Therefore, when a wet scrubber is present, it is beneficial to take measures to increase the oxidation of mercury upstream of the wet scrubber. Catalysts in SCR systems promote oxidation of mercury, and SCR controls upstream of a wet FGD system have been shown to provide high mercury capture in the range of 90 percent when burning bituminous coals.[57] The precise level of oxidation and capture will vary under different conditions. In a study by the Southern Company, five of its plants with SCR and scrubbers captured an average of 87 percent of mercury over a period of several months.[58]

Co-benefit capture rates of mercury in ESPs, fabric filters, scrubbers, or other devices for bituminous coals are generally greater than that for PRB coals. This is because the higher halogen content (e.g., chlorine) found in eastern coals promotes formation of oxidized mercury.[59]

Acid Gas Control Methods

Strong acids, such as hydrogen chloride (HCl) and hydrogen fluoride (HF), result from the inherent halogen content in the coal that is released during combustion to form acids as the flue gas cools. As with mercury content, the concentration of halogens in the coal varies widely by coal type and even within coal types. Chlorine is of greatest concern because it is usually present in higher concentrations than other halogens in U.S. coals. The U.S. EPA's proposed Air Toxics Rule for power plants sets a numerical emission limit for HCl. The HCl limit also functions as a surrogate limit for the other acid gases, which are not given their own individual emission limits under the proposed rule.

Table 9 shows HCl emission control methods for coal boilers. In principle, wet and dry SO_2 scrubbers can be used for the control of HCl and HF on power plant boilers; however, these are not likely to be necessary because lower cost methods exist. For those facilities with wet or dry scrubbers for SO_2 control, these units will likely provide the co-benefit of HCl capture. For those units that are unscrubbed, these will likely be adequately controlled through retrofit with DSI systems, and a fabric filter.

Table 9. HCl Emissions Control Methods	
Methods of Control	
Dry Sorbent Injection	Method – Dry sorbent captures HCl, downstream PM control device captures dry product Regent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels with PM control Capital Costs – Low to moderate Co-benefits – NOx and SO_2 reduction, Hg reduction, removal of chlorine precursor leading to lower dioxins/furans formation
Dry Scrubber with fabric filter	Method – Reagent + water react to capture acid gas and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – High Hg capture (esp. bituminous coal), high SO_2 capture, high PM capture
Wet Scrubber	Method – Reagent + water react to capture acid gas Reagent – Limestone, lime, caustic soda Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Highest SO_2 capture, high oxidized Hg capture, some PM capture
Co-benefit Methods of Control	
Wet or Dry Scrubbers	Method – SO_2 scrubber has high HCl removal efficiency
Coal Change	Low sulfur PRB coal is also low in chlorine content

Dry Sorbent Injection

Data from DSI commercial projects or pilot testing has indicated that acid gases can be very effectively captured by DSI using Trona, sodium bicarbonate, or hydrated lime. Although DSI is a technology that has not yet seen the wide deployment of other technologies for acid gas controls, like wet or dry scrubbers, data suggest that DSI is an effective technology for controlling emissions of acid gases, including HCl and HF. For example, as shown in Table 10, HCl capture rates of 98 percent have been measured at Mirant's Potomac River station with sorbent injection upstream of the air preheater.[60] Testing of DSI systems has shown that HCl capture is consistently well above the SO_2 capture rate, and that capture rate of HCl on an ESP was in the mid to upper 90 percent range with SO_2 capture in the 60 percent range. With fabric filters, similar HCl capture efficiencies are possible but at lower sorbent treatment rates.[61] Hydrated lime has also been shown in pilot tests to potentially achieve substantial HCl removal at low capital cost.[62]

Table 10. HCl and HF Capture at Mirant Potomac River Station		
	Trona Injection	**Sodium Bicarbonate Injection**
HCl (%)	98.8	97.8
HF (%)	78.4	88.0

DSI may be sufficiently effective in removing acid gases in combination with the existing PM control device. In some cases, however, it may be necessary to modify the existing PM control device or to install a new PM control device. If a fabric filter is installed for PM control, this will also facilitate capture of acid gases with DSI, and mercury and dioxins/furans with ACI. Such an approach will be far

less expensive than installing a wet scrubber. As indicated above, DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.

PM Emissions Control

Toxic metals other than mercury are normally in the particle form and are therefore controlled through particulate matter controls, such as ESPs and fabric filters. The proposed Air Toxics Rule for power plants sets numerical PM emission limits as a surrogate for non-mercury toxic metal emission limits. Table 11 lists PM emission control methods for pulverized coal units.

Table 11. PM Emissions Control Methods

Methods of Control	
ESP	Method – Electrostatic capture of PM, high capture efficiency Reagent – None Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Capture particle-bound mercury
Baghouse	Method – Filtration of PM, highest capture efficiency Reagent – None Typical Fuel Types – Gaseous fuels Capital Costs – High Co-benefits – High capture of mercury and other HAPs
Co-benefit Methods of Control	
Scrubber (wet or dry)	Method – Captures PM

Electrostatic Precipitator

An electrostatic precipitator (ESP) uses an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. More than 70 percent of existing coal-fired power plants are reported to have installed ESPs.[63]

In brief, an ESP works by imparting a positive or negative charge to particles in the flue gas stream. The particles are then attracted to an oppositely charged plate or tube and removed from the collection surface to a hopper by vibrating or rapping the collection surface. An ESP can be installed at one of two locations. Most ESPs are installed downstream of the air heater, where the temperature of the flue gas is between 130°C-180°C (270°F-350°F).[64] An ESP installed downstream of the air heater is known as a "cold-side" ESP. An ESP installed upstream of the air heater, where flue gas temperatures are significantly higher, is known as a "hot-side" ESP.

The effectiveness of an ESP depends in part on the electrical resistivity of the particles in the flue gas. Coal with a moderate to high amount of sulfur produces particles that are more readily controlled. Low sulfur coal produces a high resistivity fly ash that is more difficult to control. The effectiveness of an ESP also varies depending on particle size. An ESP can capture greater than 99 percent of total PM, while capturing 80 to 95 percent of $PM_{2.5}$.[65]

Depending upon the particular ESP and the applicable MACT standards, there may not be any need for further controls; however, many ESPs are decades old and were built for compliance with less stringent emission standards in mind. As a result, these facilities may need to make one or both of the following modifications to comply with new MACT standards:

- Upgrade of existing ESP – The existing ESP could be upgraded through addition of new electric fields, use of new high frequency transformer rectifier technology, or other changes. The applicability of this option will depend upon the condition and performance of the existing ESP.

- Replacement of ESP with fabric filter – A fabric filter may be installed in place of the existing ESP. In some cases, the existing ESP casing and support structure could be utilized for the baghouse. A booster fan is likely to be necessary because of the increased pressure drop across the fabric filter.

In recent years, there has been more focus on fabric filters for PM control than ESPs because of the PM capture advantages of fabric filters. As a result, there is not a great deal of available information on recent cost or installation time for ESPs. In general, however, an ESP will likely cost somewhat more and take more time to construct than a fabric filter built for the same gas flow rate because ESPs are somewhat more complex to build than a fabric filter system.

Fabric Filter or Baghouse

A fabric filter, more commonly known as a baghouse, traps particles in the flue gas before they exit the stack. Baghouses are made of woven or felted material in the shape of a cylindrical bag or a flat, supported envelope. The system includes a dust collection hopper and a cleaning mechanism for periodic removal of the collected particles.

According to EPA, a fabric filter on a coal-fired power plant can capture up to 99.9 percent of total particulate emissions and 99.0 to 99.8 percent of $PM_{2.5}$.[66] Thirty-five percent of coal-fired power plants in the U.S. have installed fabric filters.[67]

A full baghouse retrofit would generally cost somewhat more than the addition of a downstream polishing baghouse (discussed later); however, because the material and erection of the baghouse is only a portion of the total retrofit cost of any baghouse, most of the costs are the same (ductwork, booster fans, dampers, electrical system modifications, etc.). Increasing the fabric filter size by 50 percent (equivalent to a change in air to cloth ratio of 6.0 to 4.0) would yield much less than a 50 percent impact to project cost over the cost of retrofitting a polishing baghouse, perhaps in the range of 15-20 percent. A fabric filter retrofit (full or polishing) would typically be achievable in 12-24 months from design to completion, depending upon the complexity of the ductwork necessary. For example, in 2009, the Reid Gardner generating station in Nevada completed the installation of three new pulse-jet baghouses in 17 months. The retrofit required the replacement of the plant's existing mechanical separators.[68]

Rather than replacing an ESP with a fabric filter, a power plant with an existing ESP has the option of installing a downstream polishing baghouse (downstream of the existing ESP). This will capture particulate matter that escapes the ESP. Retrofit of a downstream polishing fabric filter will require addition of ductwork, a booster fan, and the fabric filter system. Costs will vary by application, particularly by the amount of ductwork needed. For example, the polishing fabric filter installed on three 90 MW boilers at Presque Isle Power Plant in Michigan cost about $125/KW (2005$). This project, however, had very long duct runs for each of the boilers and significant redundancy.[69] For a project on a single larger unit without the long duct runs, one would expect a lower cost.

Co-benefits of PM controls – PM controls, especially fabric filters, permit higher co-benefit mercury capture. Also, capture of other toxic pollutants through DSI is improved with a fabric filter. This is true

with any situation where sorbent is used to capture a pollutant because a fabric filter permits capture on the filter cake in addition to capture in-flight while ESPs permit only in-flight capture.

Control of Dioxins and Furans

Under the Air Toxics Rule, EPA has proposed a "work practice" standard for organic HAPs, including emissions of dioxins and furans, from coal-fired power plants. Power plant operators would be required to perform an annual tune-up, rather than meeting a specific emissions limit. EPA has proposed a work practice standard because it found that most organic HAP emissions from coal power plants are below current detection levels of EPA test methods. Therefore, it concluded that it is impractical to reliably measure emissions of organic HAPs. While EPA is not proposing numerical emission limits for organic HAPs, for completeness, we discuss below experience in controlling emissions of dioxins and furans from incinerators that may have relevance for co-benefits with coal power plant controls.

Emissions of dioxins and furans result from: (1) their presence in the fuel being combusted; (2) the thermal breakdown and molecular rearrangement of precursor ring compounds, chlorinated aromatic hydrocarbons; or (3) from reactions on fly ash involving carbon, oxygen, hydrogen, chorine, and a transition metal catalyst. Because dioxins and furans are generally not expected to be present in coal, the second and third mechanisms are of most interest. In both of these mechanisms, formation occurs in the post-combustion zone at temperatures over 500°C (930°F) for the second mechanism or around 250-300°C (480-575°F) for the third mechanism.[70] Once formed, dioxins and furans are difficult to destroy through combustion. Therefore, it is best to prevent their formation, or alternatively, capture them once formed.

While emissions of dioxins and furans have long been a source of concern for municipal and other waste incinerators, their emissions have not generally been controlled from power plants. Emissions of dioxins and furans are generally expected to be lower in coal combustion than in municipal waste combustion because of the relatively lower chlorine levels and the higher sulfur levels of coal.[50] Sulfur has been shown to impede dioxins and furans formation.[50,70,71] Table 12 lists the technologies for control of dioxins and furans and EPA's previously proposed institutional, commercial, and industrial boiler limits for pulverized coal units.

The extensive experience with control of dioxins and furans at incinerators has provided insights that may be relevant for power plants, while recognizing the important differences between power plants and incinerators. Because dioxins and furans are formed from organic precursors, one way to avoid their formation is to have complete combustion of organics; hence, combustion controls or oxidation catalysts can contribute to their lower formation.[70] SCR has also been shown to mitigate emissions of dioxins and furans.[50,51] Data indicate that capture of chlorine prior to the dioxins formation temperature will reduce dioxins/furans formation from municipal waste combustors.[58] Therefore, dry sorbent injection upstream of the air preheater of a coal boiler may be a means of reducing dioxins/furans formation.

Injection of activated carbon is a means that has been used to capture dioxins and furans emitted by municipal waste incinerators,[50, 70] and has demonstrated over 95 percent capture of dioxins at a hazardous waste incinerator.[72] Currently, there are not enough available data to form a definitive conclusion about how effective ACI will be at dioxins/furans capture from power plants because of the different conditions. The information available, however, suggests that it is likely to be useful in reducing dioxins and furans in the event other methods are not adequate in preventing their formation.

Table 12. Dioxins and Furans Emission Control Methods	
Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous dioxins/furans, and is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Capture of Hg
Co-benefit Methods of Control	
Combustion Controls	Method – Destruction of organic dioxins/furans precursors
Dry Sorbent Injection	Method – Captures precursor chlorine prior to dioxins/furans formation
CO or NOx Catalyst	Method – Catalyst increases oxidation of organic dioxins/furans precursors

Labor Availability

The installation of air pollution control equipment requires the effort of engineers, managers, and skilled laborers, and past history has shown that the industry has substantial capacity to install the necessary controls. Between 2008 and 2010, coal-fired power plants added approximately 60 GW of FGD controls and almost 20 GW of SCR controls with a total of 80 GW of FGD controls installed under CAIR Phase 1. Between 2001 and 2005, the electric power industry successfully installed more than 96 GW of SCR systems in response to the NOx SIP Call.

Based on a retrospective study of actual retrofit experience, it was determined that EPA and industry dramatically underestimated the ability of the air pollution control industry to support the utility industry in responding to CAIR. The study offered several reasons for why EPA and industry underestimated the capabilities of the labor market: (1) boilermakers will work overtime during periods of high demand; (2) boilermakers frequently travel to different locations for work, supplementing local available labor; (3) boilermakers work in fields other than power, such as refining/petrochemical, shipbuilding, metals industries and other construction trades, and workers can shift industry sectors with appropriate training; and (4) new workers will enter the field—for example, in advance of the NOx SIP Call, boilermakers increased their ranks by 35 percent, mostly by adding new members.[73]

In November 2010, the Institute of Clean Air Companies (ICAC), an association that represents most of the suppliers of air pollution control technology, sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO_2, and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements. In its letter, the industry association stated, "based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry's ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work."[74] Also in November 2010, the Building and Construction Trades Department of the AFL-CIO issued a letter concluding that "[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development."[75]

The electric industry has long been aware that EPA would be regulating HAPs and other pollutants from coal-fired power plants. As a result, many companies started planning their compliance strategies before EPA even proposed its Air Toxics Rule in March 2011. For example, companies have been evaluating

control technology options and establishing capital budgets.[76] Similar advance planning occurred after the proposed CAIR rule was released in December 2003. In 2004, when EPA was still working to finalize the rule, companies placed orders for more than 20 GW of FGD controls (wet and dry scrubbers).[77] Southern Company, for example, had begun planning its FGD installations in 2003, well in advance of the final rule.[78]

Conclusion

EPA's clean air rules—the Transport Rule and the Air Toxics Rule—address one of the nation's largest sources of toxic air pollution, providing important human health protections to millions of people throughout the country. Additionally, thousands of construction and engineering jobs will be created as companies invest in modern control technologies.[79]

The electric power sector has several decades of experience controlling air pollution emissions from coal-fired power plants, which should serve the industry well as it prepares to comply with the Transport Rule and the Air Toxics Rule. Many companies have already moved ahead with the upgrades necessary to comply with these future standards, demonstrating that better environmental performance is both technically and economically feasible.

In most cases, the required pollution control technologies are commercially available and have a long track record of effective performance at many coal-fired power plants in the U.S., with some operating successfully for decades. The electric power sector has demonstrated that it is capable of installing pollution controls on a large portion of the nation's generating fleet in a relatively short period of time. Also, suppliers have demonstrated the ability to deliver pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well.

Endnotes

[1] Clean Air Act, section 110(a)(2)(D), often referred to as the "good neighbor" provision of the Act, requires upwind states to prohibit certain emissions because of their impact on air quality in downwind states.

[2] U.S. Environmental Protection Agency. Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010.

[3] U.S. Environmental Protection Agency. Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call; Final Rule. Federal Register / Vol. 70, No. 91 / Thursday, May 12, 2005.

[4] *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).

[5] *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008).

[6] U.S. Environmental Protection Agency. Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010.

[7] U.S. Environmental Protection Agency. Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Page 45213. Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010.

[8] U.S. Environmental Protection Agency. Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Page 45344. Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010.

[9] U.S. Environmental Protection Agency. Fact Sheet: Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution. July 6, 2010, http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf (accessed March 17, 2011).

[10] *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[11] U.S. Environmental Protection Agency. Reducing Air Toxics from Power Plants: Regulatory Actions. March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/actions.html (accessed March 16, 2011).

[12] U.S. Environmental Protection Agency. Fact Sheet: Power Plant Mercury and Air Toxics Standards; Overview of Proposed Rule and Impacts. March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf (accessed March 17, 2011).

[13] National Association of Clean Air Agencies (NACAA). "State/Local Mercury/Toxics Program for Utilities." April 6, 2010 (updated February 8, 2011), http://www.4cleanair.org/index.asp.

[14] U.S. Environmental Protection Agency. Fact Sheet: Proposed Mercury and Air Toxics Standards. March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf.

[15] U.S. Environmental Protection Agency. Fact Sheet: Proposed Mercury and Air Toxics Standards. March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf.

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