# TESTIMONY OF

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before the

## Energy & Commerce Committee's Subcommittee on Energy & Power U.S. House of Representatives

**Hearing on**
The American Energy Initiative
Transparency in Regulatory Analysis of Impacts on the Nation Act of 2011

April 7, 2011

Mr. Chairman, ranking member Rush, and members of the subcommittee, I appreciate the opportunity to testify today on the discussion draft of the "Transparency in Regulatory Analysis of Impacts on the Nation Act of 2011," known as the "TRAIN Act." The legislation would convene a cabinet-level committee to conduct a breathtakingly ambitious analysis of how regulations required by Congress might affect energy prices in the United States in 2030. A crystal ball might well prove more effective in deriving these estimates.

My testimony makes four points:

1. **Benefits ignored.** For reasons that are left a mystery but seem amazingly misguided, the legislation ignores the benefits that would be achieved by the targeted regulations. As a result, it will produce a highly prejudiced analysis of the issues at stake in those proceedings. Rules to protect public health and the environment, especially with respect to air pollution, most definitely do not have the effect of sweeping money into a pile and setting it on fire. Rather, they save the lives of millions of people, prevent many more millions from getting sick or becoming sicker, and preserve the irreplaceable natural resources without which human life would be impossible. According to a forthcoming study by Isaac Shapiro at the Economic Policy Institute, benefits exceed costs by several orders of magnitude for all of the EPA rules finalized during the Obama Administration, and proposed rules are likely to be even more beneficial. Ignoring benefits is akin to assessing our country's well-being by carefully counting its GDP in dollars while ignoring whether Americans have a life expectancy over 50, are well enough to go to work or to school, are able to take care of each other, enjoy our leisure, or leave a sustainable world for their children.

2. **The Unknowable.** The core mission of the TRAIN Act is to determine the influence of selected environmental regulations on the costs of energy in 2020 and 2030. Under the legislation, these calculations must be completed no later than August 1, 2012, a date preceding by just a few weeks the national presidential election. I say that a crystal ball would be a more effective and less expensive way to determine these figures because of the thousands of unforeseen and unforeseeable variables that must be evaluated before calculating anything that would even simulate an accurate number. The studies required by the legislation are so ridden with uncertainty that their numbers will be not just meaningless but deceptive. The only silver lining in this quixotic effort is that it should remind Americans of the hard lesson we learned when Wall Street crashed and had reinforced when BP's oil spill prevention and mitigation plan in the Gulf failed so drastically: alleging large numbers derived from complex calculations as facts, then wrapping them up in a glossy binder, does not make the numbers or the facts either true or reliable.

3. **Great grandmother of All Unfunded Mandates.** The bill's requirements are exceptionally burdensome, yet it does not fund these costs, instead creating the great grandmother of all unfunded mandates. Much of the information needed to do the studies is in the possession of state government officials and thousands of private corporations, meaning that if the studies are developed in a responsible manner, they will be called upon to contribute these massive amounts of data without compensation

for their effort. This burden is all the more insupportable because the very few calculable estimates that lurk in the bowels of the legislation are already being compiled by the Environmental Protection Agency (EPA).

4. **Closed door process.** Although the bill has the word "transparency" in its title, the proceedings of the committee it creates to invent these estimates is exempt from the Federal Advisory Committee Act (FACA), allowing members to meet secretly with biased stakeholders who are never publicly named. Precedents for this kind of Star Chamber process designed to cripple environmentally protective rules come readily to mind, including Vice President Richard Cheney's secret Energy Taskforce and Office of Information and Regulatory Affairs Administrator Cass Sunstein's Cost of Carbon Taskforce, both of which met behind closed doors and did not disclose their membership upfront.

## Benefits

Regulations implementing the Clean Air Act, especially with respect to ozone and fine particulate matter that cause cardiovascular and respiratory problems throughout the population, are uniformly recognized as a wonderful economic bargain by experts from the right to the left of the political spectrum. Indeed, if you invite John Graham, former regulatory czar under President George W. Bush, to testify before you, he would agree enthusiastically with that statement.[1]

According to EPA's very conservative numbers, which dramatically <u>understate</u> benefits and <u>overstate</u> costs, clean air rules saved 164,300 adult lives in 2010, and will save 237,000 lives annually by 2020. EPA estimates that the economic value of Clean Air Act regulatory controls will be $2 trillion annually by 2020; costs of compliance in that year will be $65 billion. Air pollution controls saved 13 million days of work loss and 3.2 million days of school loss in 2010. By 2020, they will save 17 million work loss days and 5.4 million school loss days.[2]

EPA's estimates are based on exceptionally conservative assumptions regarding regulatory benefits that, if anything, low-ball these figures by orders of magnitude. For example, EPA says that when Clean Air Act protections prevent a non-fatal heart attack in a person 0-24 years old, the incident is worth only $84,000.[3] How many of the young people in this room would accept $84,000 to undergo a non-fatal heart attack or, for that matter, would pay that amount to avoid one? The millions of parents who have asthmatic children will be interested to

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[1] "In summary, CAIR [the Clean Air Interstate Rule] salvaged most of the sulfur- and nitrogen control benefits that were contained in the failed Clear Skies proposal. With projected benefits exceeding $100 billion per year, CAIR is one of the most beneficial rules in the history of OIRA. In summary, CAIR salvaged most of the sulfur- and nitrogen control benefits that were contained in the failed Clear Skies proposal. With projected benefits exceeding $100 billion per year, CAIR is one of the most beneficial rules in the history of OIRA." John Graham, *Saving Lives through Administrative Law and Economics*, 157 PA. L. REV. 395, 473 (2008). Graham's tribute to rulemaking under the Clean Air Act continues for several pages.

[2] *See* Envtl. Protection Agency, *The Benefits and Costs of the Clean Air Act from 1990 to 2020* (Mar. 2011), *available at* http://www.epa.gov/oar/sect812/feb11/fullreport.pdf.

[3] *Id*. at 5-18 to5-19 (Table 5-4).

learn that cleaning up the air to the point they can avoid a single emergency room visit is worth only $363 per asthmatic child.[4] Hospitals don't give you a plastic ID bracelet for that little, and the trip to the hospital with a breathless, frantic child is worthless in these calculations.

It's also worth noting that before a rule has been in effect for several years, estimates of compliance costs, which are typically provided by regulated industries, overstate those amounts significantly. For members interested in pursuing these well-documented problems with cost estimates, I have attached to my testimony two very interesting analyses of how pollution control technologies for pollution from coal-fired power plants have become both more affordable and far more effective under the Clean Air Act:

- U.S. Gov't Accountability Office, *Clean Air Act: Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions* (GAO-10-47, Oct. 2009), *available at* http://www.gao.gov/new.items/d1047.pdf
- James E. Staudt, Ph.D, Andover Technology Partners, M.J. Bradley & Assocs., *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants* (Mar. 31, 2011) (prepared for NESCAUM)

I would also refer members and staff to the following sources:

- Frank Ackerman, *The Unbearable Lightness of Regulatory Costs*, 33 FORDHAM URB. L.J. 1071(2006)
- W. Harrington & R.D. Morgenstern, et al., *On the Accuracy of Regulatory Cost Estimates*, 19 J. POL'Y ANALYSIS & MGMT. 297 (2000)
- H. Hodges, *Falling Prices: Costs of Complying with Environmental Regulations Almost Always Less Than Advertised* (Econ. Pol'y Inst., 1997)
- U.S. Congress, Office of Tech. Assessment, *Gauging Control Technology and Regulatory Impacts in Occupational Safety and Health—An Appraisal of OSHA's Analytic Approach*, U.S. Gov't Printing Office OTA-ENV-635, *available at* http://www.fas.org/ota/reports/9531.pdf
- Thomas O. McGarity & Ruth Ruttenberg, *Counting the Cost of Health, Safety, and Environmental Regulation*, 80 TEX. L. REV. 1997, 2042- 44 (2002)
- Ruth Ruttenberg, *Not Too Costly After All: An Examination of the Inflated Cost Estimates of Health, Safety, and Environmental Protections*, (Public Citizen White Paper, Feb. 2004), *available at* http://www.citizen.org/documents/ACF187.pdf

As for the benefits achieved by the rules that are targeted by the TRAIN Act discussion draft, Center for Progressive Reform (CPR) Policy Analyst James Goodwin and I prepared the following summary showing how the projected benefits of the four most important rules far outnumber their estimated costs. And note please that some of the most significant benefits of these regulations were not monetized, because they frankly defy monetization. They were therefore dismissed by cost-benefit analysis as having no economic value whatsoever, a huge

[4] *Id*.

liability of cost-benefit analysis that not coincidentally always leads to understating the value of a proposed regulation.

## Proposed Interstate Transport Rule

EPA's proposed Interstate Transport Rule requires power plants in 31 eastern states and in the District of Columbia to significantly reduce their emissions of sulfur dioxide and nitrogen oxide pollution. These pollutants contribute to the formation of ground level ozone and fine particulate matter—both of which are extremely harmful to public health and the environment—which travel long distances across state lines, making it difficult for downwind states to comply with national clean air standards

- **Total monetized benefits:** $110 billion and $290 billion by 2014.[5]
- **Costs:** $2.0 billion to $2.2 billion.[6]
- **Health impacts of fine particulate matter:**
  - Fine particulate matter "contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream."[7]
  - Ingestion of fine particulate matter can cause "premature death in people with heart or lung disease."[8]
- **Health benefits of reduced fine particulate matter[9]**:
  - 14,000 to 36,000 fewer premature mortalities
  - 9,200 fewer cases of chronic bronchitis
  - 22,000 fewer non-fatal heart attacks
  - 11,000 fewer hospitalizations (for respiratory and cardiovascular disease combined)
  - 10 million fewer days of restricted activity due to respiratory illness
  - 1.8 million fewer work-loss days
- **Health impacts of ozone:**
  - "Breathing ozone can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground-level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue."[10]

[5] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45210, 45344 (proposed Aug. 2, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 72, 78, and 97).
[6] *Id*. at 45348.
[7] Envtl. Protection Agency, *Particulate Matter: Health and Environment*, http://www.epa.gov/pm/health.html (last visited Apr. 5, 2011).
[8] *Id*.
[9] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45210, 45346 (proposed Aug. 2, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 72, 78, and 97).
[10] Envtl. Protection Agency, *Ground-Level Ozone: Health and Environment*, http://www.epa.gov/air/ozonepollution/health.html (last visited Apr. 5, 2011).

- **Health benefits of reduced ozone[11]**:
  - 50 to 230 fewer premature mortalities
  - 690 fewer hospital admissions for respiratory illnesses
  - 230 fewer emergency room admissions for asthma
  - 300,000 fewer days with restricted activity levels
  - 110,000 fewer days where children are absent from school due to illnesses
- **Environmental benefits** (not quantified or monetized)[12]:
  - Reduced acid rain, which harms rivers streams, and forest ecosystems
  - Reduced ozone damage to vegetation

## Proposed Ozone NAAQS

EPA's proposed revision of the ozone National Ambient Air Quality Standard (NAAQS) would reduce the allowable 8-hour primary standard (a standard designed to ensure that pollution levels are kept low enough to protect public health) from 0.075 parts per million (ppm) to between 0.060 and 0.070 ppm in accordance with the recommendations of the EPA's Clean Air Science Advisory Committee (CASAC). (The agency is also considering lowering the standard even more to 0.055 ppm, as well as maintaining the existing standard.)

- **Total monetized benefits:** Between $53 billion and $160 billion (0.055 ppm standard) to between $6.9 billion and $18 billion (0.075 ppm standard).[13]
  - Monetized benefits include reduced health effects from reduced exposure to ozone, reduced health effects from reduced exposure to fine particulate matter, and improvements in visibility.[14]
- **Costs:** Between $78 billion and $130 billion (0.055 ppm standard) to between $7.6 billion and $8.8 billion (0.075 ppm standard).[15]
- **Health benefits of rule[16]:**
  - 760 to 22,200 fewer premature mortalities
  - 470 to 3,200 fewer cases of chronic bronchitis
  - 1,300 to 7,500 fewer nonfatal heart attacks
  - 88,000 to 600,000 fewer work-loss days
  - 190,000 to 3.7 million fewer school loss days

## NESHAP for Major Sources: Boilers

EPA's rule establishing National Emissions Standards for Hazardous Air Pollutants (NESHAP) for major source boilers (*i.e.*, larger boilers used to power large industrial and commercial

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[11] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45210, 45346-47 (proposed Aug. 2, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 72, 78, and 97).
[12] *Id*. at 45349-52.
[13] Envtl. Protection Agency, *Summary of the updated Regulatory Impact Analysis (RIA) for the Reconsideration of the 2008 Ozone National Ambient Air Quality Standard (NAAQS)* S1-4 (Table S1.1) (2010), *available at* http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.
[14] *Id*. at S1-3.
[15] *Id*. at S1-4 (Table S1.1).
[16] *Id*. at S2-24 (Table S2.13),S3-5 (Table S3.1).

facilities) requires these facilities to significantly reduce their emissions of toxic air pollutants, which include mercury, other metals, polycyclic organic matter (POM), and dioxins.

- **Total monetized benefits:** Between $20 billion and $54 billion.[17]
  - "The benefit categories associated with the emission reduction anticipated for this rule can be broadly categorized as those benefits attributable to reduced exposure to hazardous air pollutants (HAPs) and those attributable to exposure to other pollutants. Because we were unable to monetize the benefits associated with reducing HAPs, all monetized benefits reflect improvements in ambient PM2.5 and ozone concentrations. This results in an underestimate of the total monetized benefits."[18]
- **Costs:** $1.5 billion.[19]
- **Health co-benefits of the rule[20]**:
  - 2,500 to 6,500 fewer premature mortalities
  - 1,600 fewer cases of chronic bronchitis
  - 4,000 fewer nonfatal heart attacks
  - 1,910 fewer hospitalizations (for respiratory and cardiovascular disease combined)
  - 2,400 fewer emergency room visits
  - 310,000 fewer work-loss days
  - 810 fewer school loss days
- **Un-quantified and un-monetized benefits of the rule[21]**:
  - The direct health benefits from reducing hazardous air pollutants (*e.g.*, mercury, hydrogen chloride, hydrogen cyanide, toluene, formaldehyde, polycyclic aromatic hydrocarbons, dioxins, etc.):
    - Various forms of cancer
    - Noncancer health effects can include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems
  - Reduced ozone damage to vegetation

## Proposed NESHAP: Utilities

EPA's proposed NESHAP for utilities (*i.e.*, large power plants) requires these facilities to significantly reduce their emissions of toxic air pollutants, which include mercury (Hg), arsenic, chromium, nickel, hydrogen chloride (HCl), and hydrogen fluoride (HF).

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[17] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 76 Fed. Reg. 15608, 15651 (Mar. 21, 2011) (to be codified at 40 C.F.R. pt. 63).
[18] *Id*.
[19] *Id*. at 15654.
[20] *Id*. at 15652 (Table 5).
[21] Envtl. Protection Agency, *Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* 7-37 – 7-57 (2011), *available at* http://www.epa.gov/ttn/ecas/regdata/RIAs/boilersriafinal110221_psg.pdf.

- **Total monetized benefits** between $53 billion and $140 billion.[22]
    - "These estimates reflect the economic value of the Hg benefits as well as the PM2.5 and CO2-related co-benefits."[23]
    - "It should be emphasized that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing various HAP have not been monetized in this analysis, including reducing 68,000 tons of HCl, and 3,200 tons of other metals each year."[24]
- **Costs:** $10.9 billion.[25]
- **Health benefits of rule[26]:**
    - 17,000 fewer premature deaths
    - 11,000 fewer heart attacks
    - 120,000 fewer asthma attacks
    - 12,200 fewer hospital and emergency room visits
    - 4,500 fewer cases of chronic bronchitis
    - 5.1 million fewer restricted activity days
    - 850,000 fewer work-loss days
- **Environmental benefits of rule** (not quantified or monetized)[27]:
    - Increased agricultural crop and commercial forest yields
    - Visibility improvements
    - Reduced acid rain, which harms rivers streams, and forest ecosystems

## Proposed Coal Ash Rule

Last but not least, the TRAIN Act targets EPA's proposed coal ash rule, a measure that would require utilities with coal-fired power plants to stabilize the huge dump sites where they have deposited the ash generated by such combustion.[28] U.S. power plants generate 140 million tons of coal ash annually. Byproducts of burning coal include a variety of toxic metals that are heavily concentrated in these residues, and these concentrations will increase as air pollution control technologies remove more toxic particles from the gas and deposit them in the ash. Or, in other words, substances considered to be hazardous air pollutants are transferred to land and water when the ash is disposed, causing additional environmental harm. Some of this coal ash is

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[22] Envtl. Protection Agency, *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* 556 (pre-publication draft of proposed rule), *available at* http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposal.pdf.
[23] *Id*.
[24] *Id*. at 562.
[25] Envtl. Protection Agency, *Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report* 1-1 (2011), *available at* http://www.epa.gov/ttn/ecas/regdata/RIAs/ToxicsRuleRIA.pdf.
[26] *Id*. at 1-4 (Table 1-2).
[27] *Id*. at 1-9 – 1-10 (Table 1-4).
[28] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128, 35,211 (proposed June 21, 2010) (to be codified at 40 C.F.R. pts. 257, 261, 264, 265, 268, 271, 302).

recycled, but about 70 percent (94 million tons annually, more than twice the amount of hazardous waste now generated in the U.S.), is dumped into landfills and surface impoundments. On December 22, 2008, one such facility operated by TVA burst open, releasing *one billion gallons* of inky coal ash sludge across 300 acres of Kingston, Tennessee.[29]

Of 629 impoundments nationwide, one-third were not designed by a professional engineer, and 96 are at least 40 feet tall and at least 25 years old. EPA has identified 50 "high-hazard" surface impounds likely to kill people if they fail. The Pennsylvania Department of Environmental Protection predicts that the failure of the Little Blue Run ash basin could kill 50,000 people. Beyond the catastrophic implications of a sudden spill, such sites, which are typically unlined, cause irreversible contamination of groundwater by such toxic metals as arsenic, cadmium, chromium, lead, mercury, and selenium. About 140 cases of such contamination have already been documented.[30]

I have attached to this testimony a chart showing the coal ash disposal sites in the districts of members of the subcommittee. I urge the subcommittee to consider the hazards posed by these sites before you vote on whether to adopt yet another weapon to eliminate such protective regulation.

## The Unknowable

The core mission of the legislation before the subcommittee is to determine the influence of selected environmental regulations on the costs of energy in 2020 and 2030. These calculations must be completed no later than August 1, 2012, a date preceding by just a few weeks the national presidential election. In this instance, haste most assuredly will mean waste, except in the sense that the very large estimates that the bill's sponsors hope will be plucked from the ether will be used to further cripple EPA's efforts to implement the Clean Air Act.

Indeed, one irony that underlies this entire exercise is the argument often made by climate change skeptics to the effect that scientific projections of what might happen to climate over the next ten, twenty, or thirty years amount to sheer conjecture and do not afford a reliable basis for action. Yet these same skeptics would undoubtedly endorse this effort to demonstrate that if we act to control carbon emissions, we won't be able to afford the energy we need to stay warm, cool off, or even read a book. Only in this context, we have no ice cores, climate history, or other scientific evidence to rely upon, and instead must project the future course of history around the globe, teasing out with false precision whether saving Washington, New York, Chicago, or Los Angeles from dangerous smog that requires us to stay inside all day is truly worth an unknowable increment of increase on utility bills we will receive two decades hence.

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[29] Stephanie Smith, *Months After Ash Spill, Tennessee Town Still Choking*, CNN, July 13, 2009, http://articles.cnn.com/2009-07-13/health/coal.ash.illnesses_1_coal-ash-drinking-water-coal-power-plant?_s=PM:HEALTH; *Toxic Tsunami*, NEWSWEEK, July 18, 2009, http://www.newsweek.com/2009/07/17/toxic-tsunami.html.

[30] For further information on the proposed rule, and the hazards posed by the sites, see CPR Comments filed on November 19, 2010 and available at http://www.progressivereform.org/articles/Coal_Ash_Comments_Steinzor_111910.pdf.

Imagine for a moment that you could muster a meeting of the most sophisticated and knowledgeable experts on global oil prices. Throw in climate scientists, military experts, geologists, and the leaders of the ten countries with the largest deposits of oil, natural gas, and coal in the world. Ask the assembled group to tell you what the wholesale costs of these fuels will be in six months, and you will get lots of discussion that could take hours, if not days, and might even involve a range of estimates orders of magnitude apart depending on the perspective of the estimator. Now ask what the wholesale costs of these fuels will be in 2030. You would get laughter, shrugs, and protestations of disbelief that you are serious.

Over the last several weeks, we have seen popular uprisings course across the Middle East, sending gas prices through the roof. No one knows how these deeply rooted social cataclysms will play out, and they are likely to play a far more significant role in determining energy prices 10 or 20 years hence than projected costs of an EPA regulation that has not even been finalized yet. Unless sponsors of the legislation intend for its committee to simply pull the likely price of gas, oil, and coal in 2030 out of thin air, such projections are impossible to calculate in any reliable manner. Or consider the potential role of nuclear energy in America's future, a goal supported both by the President and many members of this committee. Nuclear energy will be far less regulated by the Clean Air Act than its fossil fuel counterparts. But who could have anticipated that a tsunami across the ocean in Japan would threaten its immediate future in the U.S.?

To the extent that the real answer sought by the legislation is how much the environmental rules under the Clean Air Act are likely to cost, as my earlier summary of benefits for four of the rules targeted by the legislation indicates, we have only to consult the elaborate regulatory impact assessments prepared by EPA under the stern oversight of OMB. But without the denominator of this fraction—how much energy will cost in 2020 or 2030, even those elaborate projections would not do the job this legislation demands.

Lastly, the legislation makes the job of knowing the unknowable even more ridiculously impossible by including rules that have not yet been promulgated in final form. These include most of the Clean Air Act rules explained above, which at least have been proposed by publication in the *Federal Register*. But it also includes potential rules that are at very early stages of development, including actions to improve visibility in certain national parks and wilderness areas (Clean Air Act Sections 169A and 169B) and rules to establish or modify a NAAQS.

## Great Grandmother of All Unfunded Mandates

The discussion draft of the TRAIN Act contains a provision requiring the evaluation of how "covered actions" will affect energy costs and the reliability of the grid in 2020 and 2030. Covered actions are defined as "any" action occurring after January 1, 2009 and involving restrictions imposed by federal, state, or local governments on greenhouse gases using their Clean Air Act authority. In yet another striking paradox, the bill's drafters ignore how burdensome this requirement will be for countless thousands of public and private sector parties, even though their disgust with the burdens of regulatory requirements is ostensibly what drives their support for the legislation. One must conclude that in the view of the drafters of this legislation, some burdens are OK to impose, so long as they don't help fight climate change or otherwise protect the environment. The mandate that some group of government accountants and economists quantify the implications of those potential requirements for projects in the planning stage for 2030 is nothing less than the great grandmother of all unfunded mandates.

To do a responsible job, federal numbers crunchers would be compelled to send information requests to every federal, state, and local government office--as well as any private sector company--that might be in a position to control the development or operation of a greenhouse gas-generating facility 20 years in the future. The reams of data that would be generated by such requests, not to mention the government resources that would be consumed in the analysis of such data, are quite literally mind-boggling.

In December 2010, EPA announced plans to issue an New Source Performance Standard (NSPS) limiting GHG emissions from fossil fueled power plants by May of 2012 and an NSPS limiting GHG emissions from petroleum refineries by November of 2012, as part of a settlement agreement with several environmental groups and state and local governments.[31] The agency has not yet issued any proposed rules, so the precise details of the NSPSs are not clear. The Clean Air Act requires EPA to set NSPSs based on the best demonstrated technology for controlling emissions, and to review and revise existing NSPSs to account for advances in emissions control technology. EPA has provided no information about its assessment of the potential emissions control technology, or whether it will consider controversial control technologies like carbon capture and sequestration. Crunching numbers in the face of such uncertainty will be a waste not only of government but of private sector resources.

## Secret, Not to Mention Biased, Government

The public's confidence in and respect for our government is directly influenced by the transparency and sunshine provisions that good government laws like the Federal Advisory Committee Act (FACA) provide. Congress passed FACA because the federal government routinely consults a wide variety of scientists, engineers, business people, and citizens about public policy. The statute requires these consultations to be open, accountable, and balanced, including stakeholders with a full range of views on the issues. These requirements apply to any advisory group that is established or utilized by federal agencies and that has at least one member who is not a federal employee. Agencies must give advanced notice of meetings, keep minutes, permit interested persons to attend, and make available to the public any records or documents received by the group. Most importantly, FACA prohibits the stacking of advisory panels with one point of view. Agencies must ensure that each committee is fairly balanced in its membership in terms of the points of view represented and the functions to be performed.

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[31] Press Release, Envtl. Protection Agency, EPA to Set Modest Pace for Greenhouse Gas Standards (Dec. 23, 2011), http://yosemite.epa.gov/opa/admpress.nsf/6424ac1caa800aab85257359003f5337/d2f038e9daed78de8525780200568bec!OpenDocument.

Incredibly, despite its title, the Transparency in Regulatory Analysis of Impacts on the Nation Act of 2011 would exempt the deliberations of the special "Committee for the Cumulative Analysis of Regulations that Impact Energy and Manufacturing in the United States" from FACA, and from any obligation to conduct its affairs in public or make the basis for its conclusions transparent. I appreciate that whoever named the bill needed a "T" to round out the acronym, but "transparency" is the last thing this bill can claim. Let me suggest that you add the phrase, "So-called" up front – the So-called Transparency in Regulatory Analysis of Impacts on the Nation Act. That would make both the name, and the acronym, STRAIN, much more accurate.

As disturbing, the legislation stacks the committee with federal officials—and a single private sector representative (a representative from the North American Electric Reliability Corporation)—who can be expected to share a clear bias against EPA regulations that the electric power and energy production industries might deem inconvenient. In fact, EPA itself is the only member of the committee that might speak up in defense of those rules, and it is hard to imagine why its sole representative would make the effort when she is so badly outnumbered and the meeting is occurring behind closed doors.

## Conclusion

Mr. Chairman, and members of the subcommittee, the discussion draft of the TRAIN Act is a collection of bad ideas that cannot be executed in service of a dangerous and misguided objective. These requirements will waste time and money and could cost lives. If Congress is truly interested in making government more effective, it should drop this politically motivated piece of legislation and let EPA get back to work.

## Witness Background

I am a law professor at the University of Maryland School of Law and the President of the Center for Progressive Reform (CPR) (http://www.progressivereform.org/). Founded in 2002, CPR is a 501(c)(3) nonprofit research and educational organization comprising a network of sixty scholars across the nation who are dedicated to protecting health, safety, and the environment through analysis and commentary. I joined academia mid-career, after working for the Federal Trade Commission for seven years and this committee for five years, and serving as outside counsel for a wide variety of small and mid-sized businesses for seven years. My work on environmental regulation includes four books, and over twenty-seven articles (as author or co-author). My most recent book, published by the University of Chicago Press, is *The People's Agents and the Battle to Protect the American Public: Special Interests, Government, and Threats to Health, Safety, and the Environment*, which I co-authored with Professor Sidney Shapiro of Wake Forest University's School of Law, analyzes the state of the regulatory system that protects public health, worker and consumer safety, and natural resources, concluding that these agencies are under-funded, lack adequate legal authority, and are undermined by political pressure motivated by special interests. I have served as consultant to EPA and have testified previously before Congress on regulatory subjects on numerous occasions.

Attachments:

- U.S. Gov't Accountability Office, *Clean Air Act: Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions* (GAO-10-47, Oct. 2009), *available at* http://www.gao.gov/new.items/d1047.pdf
- James E. Staudt, Ph.D, Andover Technology Partners, M.J. Bradley & Assocs., *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants* (Mar. 31, 2011) (prepared for NESCAUM)
- Chart of Coal Ash Sites in Subcommittee Members' Districts

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

March 31, 2011

NESCAUM

Attachment A

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

Prepared For:

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## Table of Contents

## 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

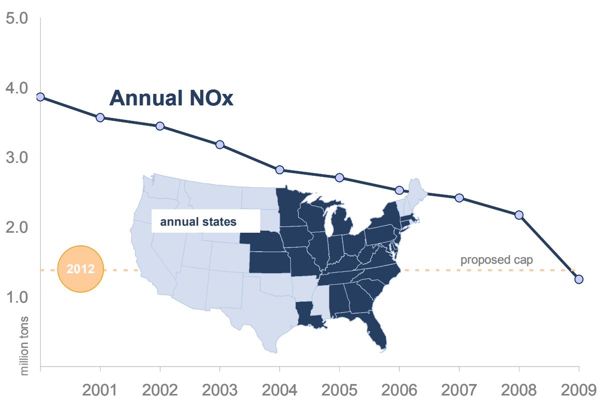
| Regulated Pollutants | Affected Sources | Compliance Dates | Regulatory Mechanism |
|---|---|---|---|
| Sulfur dioxide ($SO_2$)<br><br>Nitrogen oxides (NOx) | Fossil fuel-fired power plants 25 MW and larger in 31 eastern states and DC | Phase 1: 2012<br>Phase 2: 2014 | EPA's preferred approach would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

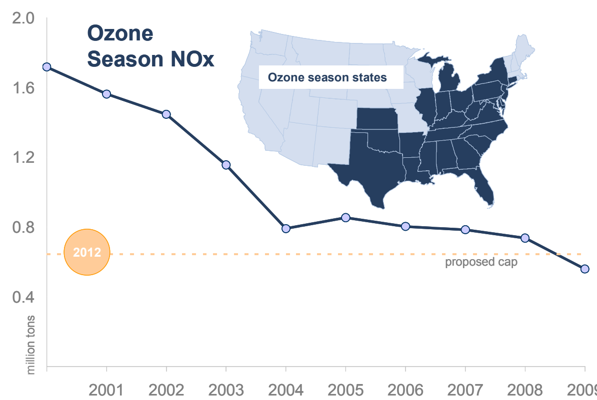
EPA's proposed emissions caps for $SO_2$ and NOx are summarized in the following figures. EPA notes in the proposed rule that additional ozone season (May 1 to September 30) NOx reductions will likely be needed to attain the national ozone standards.[6] Therefore, the agency plans to propose a new transport 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

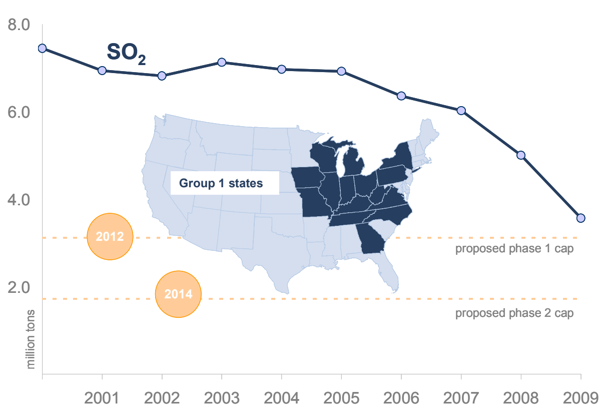
EPA's proposed Transport Rule would establish two NOx programs: (1) an annual NOx program, and (2) an ozone season (summer time) NOx program (see map below). Annual NOx emissions would be capped at 1.4 million tons per year beginning in 2012. The 2012 cap represents a 10 percent increase over 2009 emissions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

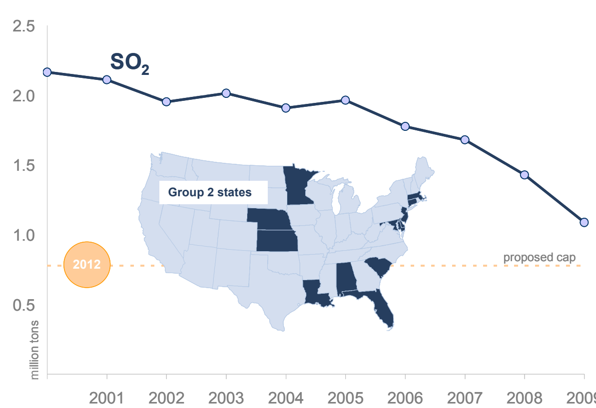



## Clean Air Transport Rule: Proposed $SO_2$ Emissions Caps

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<br>Non-mercury metals, such as arsenic, chromium, cadmium, and nickel<br>Organic HAPs (e.g., dioxins/furans)<br>Acid gases (HCl, HF) | Coal- and oil-fired power plants 25 MW and larger | Early 2015<br>**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<br>Reagent – None<br>Typical fuel types – Powder River Basin coal and lower sulfur bituminous coal<br>Capital Cost – Low<br>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<br>Reagent – Trona, sodium bicarbonate, hydrated lime<br>Typical Fuel Types – Most often solid fuels (i.e., coals – lignite, sub-bituminous, bituminous)<br>Capital Costs- Low to moderate<br>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<br>Reagent – Hydrated lime<br>Typical Fuel Types – Coal<br>Capital Costs – High<br>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<br>Reagent – Limestone, lime, caustic soda<br>Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil<br>Capital Costs – High<br>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<br>Reagent – Limestone, lime, etc.<br>Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil<br>Capital Costs – Low to moderate<br>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

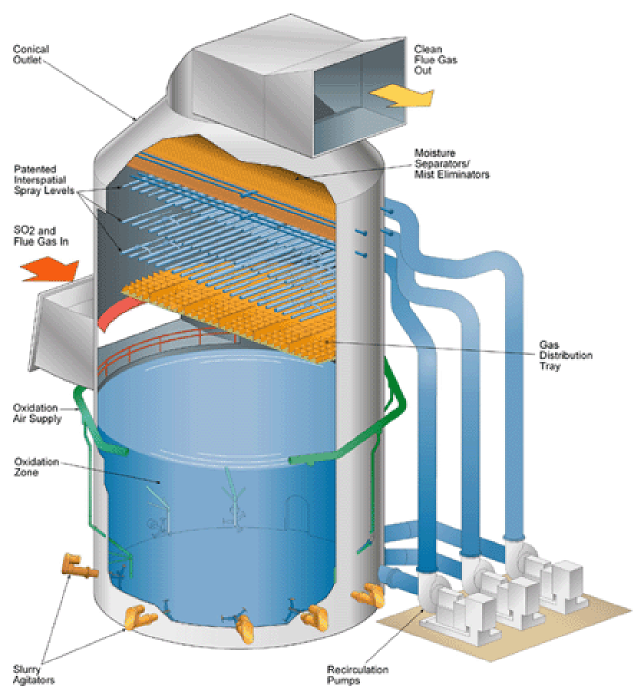



**Figure 1. Wet Flue Gas Desulfurization**
Image courtesy of Babcock and Wilcox Company

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.

## 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.

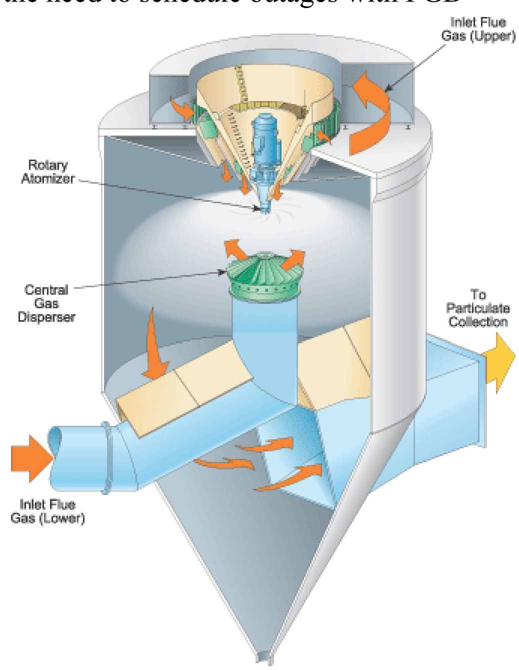



**Figure 2**. Dry Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

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]

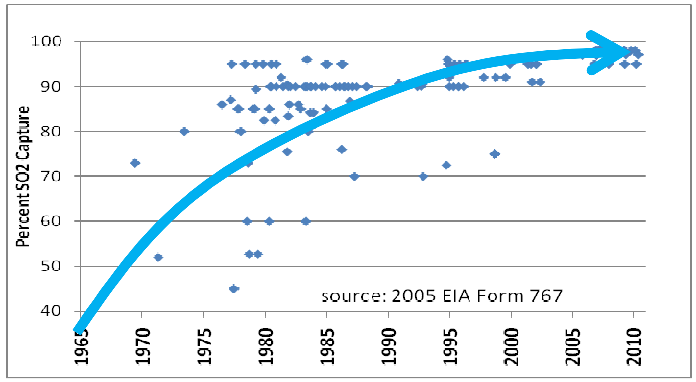


**Figure 3. Historical Trends in Limestone Wet Scrubber $SO_2$ Removal Efficiency of Limestone Wet Scrubbing Systems**

## 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<br>Reagent – None<br>Typical fuel types – All fuels<br>Capital Cost – Low to moderate<br>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%<br>Regent – Urea or ammonia<br>Typical Fuel Types – Most often solid or liquid fuels<br>Capital Costs- Low<br>Co-benefits - None |
| **Selective Catalytic Reduction** | Method – Reagent reacts with NOx across catalyst bed and reduces NOx at high rates of about 90%<br>Reagent – Ammonia (or urea that is converted to ammonia)<br>Typical Fuel Types – Any fuel<br>Capital Costs – High<br>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.

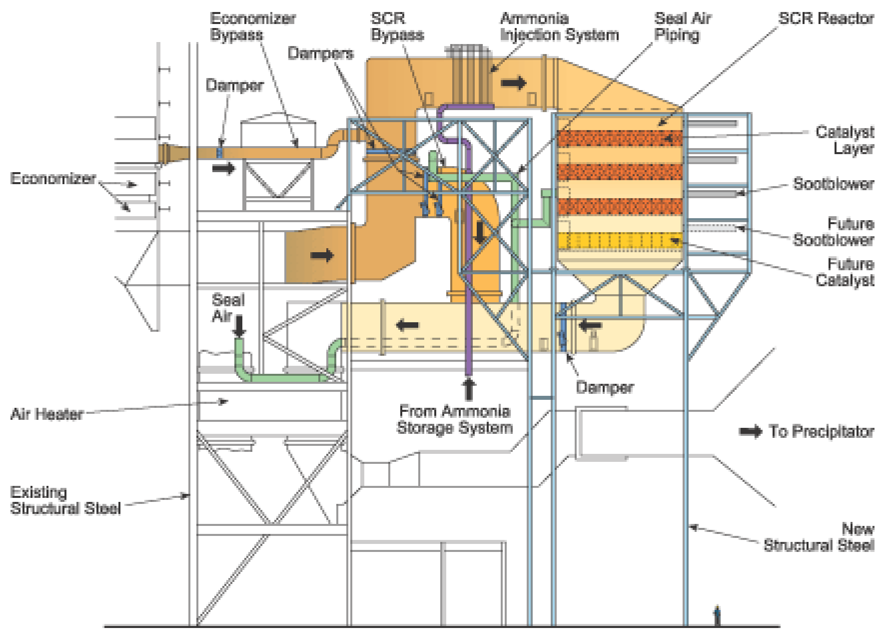



**Figure 4**. Selective Catalytic Reduction (Retrofit Installation)
Image courtesy of Babcock and Wilcox Company

## 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<br>Reagent – Powdered Activated Carbon<br>Typical Fuel Types – Any fuel, but downstream PM control needed<br>Capital Costs – Low<br>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<br>Reagent – Halogen containing additive<br>Capital Costs – Negligible<br>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<br>Regent – Trona, sodium bicarbonate, hydrated lime<br>Typical Fuel Types – Most often solid fuels with PM control<br>Capital Costs – Low to moderate<br>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<br>Reagent – Hydrated lime<br>Typical Fuel Types – Solid fuels<br>Capital Costs – High<br>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<br>Reagent – Limestone, lime, caustic soda<br>Typical Fuel Types – Solid fuels<br>Capital Costs – High<br>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<br>Reagent – None<br>Typical Fuel Types – Solid fuels<br>Capital Costs – High<br>Co-benefits – Capture particle-bound mercury |
| **Baghouse** | Method – Filtration of PM, highest capture efficiency<br>Reagent – None<br>Typical Fuel Types – Gaseous fuels<br>Capital Costs – High<br>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<br>Reagent – Powdered Activated Carbon<br>Typical Fuel Types – Any fuel, but downstream PM control needed<br>Capital Costs – Low<br>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.

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[78] Institute of Clean Air Companies (ICAC). Letter to Senator Thomas Carper, U.S. Senate. November 3, 2010, http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf (accessed March 17, 2011).

[79] Ceres. New Jobs-Cleaner Air: Employment Effects Under Planned Changes to the EPA's Air Pollution Rules. February 2011.

United States Government Accountability Office

GAO

Report to the Chairman, Subcommittee on Clean Air and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate

October 2009

# CLEAN AIR ACT

# Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions

GAO

Accountability * Integrity * Reliability

GAO-10-47

Attachment B

October 2009

GAO Accountability·Integrity·Reliability

# Highlights

Highlights of GAO-10-47, a report to the Chairman, Subcommittee on Clean Air and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate

# CLEAN AIR ACT

## Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions

### Why GAO Did This Study

The 491 U.S. coal-fired power plants are the largest unregulated industrial source of mercury emissions nationwide, annually emitting about 48 tons of mercury—a toxic element that poses health threats, including neurological disorders in children. In 2000, the Environmental Protection Agency (EPA) determined that mercury emissions from these sources should be regulated, but the agency has not set a maximum achievable control technology (MACT) standard, as the Clean Air Act requires. Some power plants, however, must reduce mercury emissions to comply with state regulations or consent decrees.

After managing a long-term mercury control research and development program, the Department of Energy (DOE) reported in 2008 that systems that inject sorbents—powdery substances to which mercury binds—into the exhaust from boilers of coal-fired power plants were ready for commercial deployment. Tests of sorbent injection systems, the most mature mercury control technology, were conducted on a variety of coal types and boiler configurations—that is, on boilers using different air pollution control devices. In this context, GAO was asked to examine (1) reductions achieved by mercury control technologies and the extent of their use at power plants, (2) the cost of mercury control technologies, and (3) key issues EPA faces in regulating mercury emissions from power plants. GAO obtained data from power plants operating sorbent injection systems. EPA and DOE provided technical comments, which we incorporated as appropriate.

View GAO-10-47 or key components.
For more information, contact John B. Stephenson at (202) 512-3841 or stephensonj@gao.gov.

### What GAO Found

Commercial deployments and 50 DOE and industry tests of sorbent injection systems have achieved, on average, 90 percent reductions in mercury emissions. These systems are being used on 25 boilers at 14 coal-fired plants, enabling them to meet state or other mercury emission requirements—generally 80 percent to 90 percent reductions. The effectiveness of sorbent injection is largely affected by coal type and boiler configuration. Importantly, the substantial mercury reductions using these systems commercially and in tests were achieved with all three main types of coal and on boiler configurations that exist at nearly three-fourths of U.S. coal-fired power plants. While sorbent injection has been shown to be widely effective, DOE tests suggest that other strategies, such as blending coals or using other technologies, may be needed to achieve substantial reductions at some plants. Finally, some plants already achieve substantial mercury reductions with existing controls designed for other pollutants.

The cost of the mercury control technologies in use at power plants has varied, depending in large part on decisions regarding compliance with other pollution reduction requirements. The costs of purchasing and installing sorbent injection systems and monitoring equipment have averaged about $3.6 million for the 14 coal-fired boilers operating sorbent systems alone to meet state requirements. This cost is a fraction of the cost of other pollution control devices. When plants also installed a fabric filter device primarily to assist the sorbent injection system in mercury reduction, the average cost of $16 million is still relatively low compared with that of other air pollution control devices. Annual operating costs of sorbent injection systems, which often consist almost entirely of the cost of the sorbent itself, have been, on average, about $675,000. In addition, some plants have incurred other costs, primarily due to lost sales of a coal combustion byproduct—fly ash—that plants have sold for commercial use. The carbon in sorbents can render fly ash unusable for certain purposes. Advances in sorbent technologies that have reduced sorbent costs at some plants offer the potential to preserve the market value of fly ash.

EPA's decisions on key regulatory issues will have implications for the effectiveness of its mercury emissions standard. In particular, the data EPA decides to use will impact (1) the emissions reductions it starts with in developing its regulation, (2) whether it will establish varying standards for the three main coal types, and (3) how the standard will take into account a full range of operating conditions at the plants. These issues can affect the stringency of the MACT standard EPA proposes. For example, if EPA uses data from its 1999 power plant survey as the basis for its mercury standard, the standard could be less stringent than what has been broadly demonstrated in recent commercial deployments and DOE tests of sorbent injection systems at power plants. On July 2, 2009, EPA announced that it would seek approval from the Office of Management and Budget to conduct an information collection request to update existing emissions data, among other things, from power plants.

# Contents

## Tables



## Figure



**Abbreviations**

| | |
|---|---|
| BTU | British thermal units |
| CEMS | continuous emissions monitoring systems |
| DOE | Department of Energy |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| MACT | maximum achievable control technology |
| OMB | Office of Management and Budget |

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Accountability * Integrity * Reliability

**United States Government Accountability Office**
**Washington, DC 20548**

October 8, 2009

The Honorable Thomas R. Carper
Chairman
Subcommittee on Clean Air
and Nuclear Safety
Committee on Environment
and Public Works
United States Senate

Dear Mr. Chairman:

Mercury is a toxic element that poses human health threats—including neurological disorders in children that impair their cognitive abilities. Coal-fired power plants, the nation's largest electricity producers, represent the largest unregulated industrial source of mercury emissions in the United States.[1] In 2000, the Environmental Protection Agency (EPA) determined that it was "appropriate and necessary" to regulate mercury emissions from coal-fired power plants under section 112 of the Clean Air Act. Subsequently, in 2005, EPA chose to promulgate a cap-and-trade program,[2] rather than establish a maximum achievable control technology (MACT) standard to control mercury emissions as required under section 112. However, the cap-and-trade program was vacated by the D.C. Circuit Court of Appeals in February 2008 before EPA could implement it.

EPA must now develop a MACT standard to regulate mercury emissions from coal-fired power plants. As prescribed by the Clean Air Act, the MACT standard shall require that mercury emissions from all coal-fired boilers be reduced to the average amount emitted by the best performing

[1]EPA's 1999 data, the agency's most recent available data on mercury emissions, show that the 491 U.S. coal-fired power plants annually emit 48 tons of mercury into the air. These emissions are unregulated at the federal level and largely unregulated at the state level.

[2]EPA's cap-and-trade program, known as the Clean Air Mercury Rule, was established under Clean Air Act section 111 and set a cap on mercury emissions of 38 tons for 2010 and a second phase cap of 15 tons for 2018. The rule included a model cap-and-trade program that states could adopt to achieve and maintain their mercury emissions budgets. States could join the trading program by adopting the model trading rule in state regulations, or by adopting regulations that mirrored the necessary components of the model trading rule. States could also opt out of the trading program entirely as long as they imposed controls on plants sufficient to meet the mercury budget set for the state by the federal rule.

12 percent of coal-fired boilers.[3] While developing MACT standards for hazardous air pollutants can take up to 3 years, EPA may be required to promulgate its standard sooner depending on the outcome of a pending lawsuit. Specifically, EPA has been sued by several environmental groups requesting that the EPA Administrator promulgate a MACT standard to regulate mercury emissions for coal-fired power plants by a date no later than December 2010.

The Department of Energy's (DOE) National Energy Technology Laboratory has worked with EPA and the Electric Power Research Institute (EPRI),[4] among others, during the past 10 years on a comprehensive mercury control technology test program. Mercury is emitted in such low concentrations that its removal and measurement are particularly difficult, and it is emitted in several forms, some of which are harder to capture than others.[5] The DOE program has focused largely on testing sorbent injection systems[6] on all coal types and at a variety of boiler configurations at operating power plants.[7] This regimen of testing was important because the type of coal burned and the variety of air pollution control devices for other pollutants already installed at power plants can impact the effectiveness of sorbent injection systems. For example, some power plants already achieve mercury reductions as a "co-benefit" of using devices designed to reduce other pollutants, such as sulfur dioxide, nitrogen oxides, and particulate matter.

According to a 2008 report in which DOE described its mercury technology testing program, "DOE successfully brought mercury control technologies to the point of commercial-deployment readiness." Nonetheless, the report stated that while the results achieved during

[3]According to EPA, its MACT is to also cover the other hazardous air pollutants listed in the Clean Air Act as well as emissions from oil-fired power plants. For categories with fewer than 30 sources, the MACT standard must be set, at least, at the average level achieved by the top five performing units.

[4]EPRI is an independent non-profit company funded by electricity producers that conducts research and development in the electricity sector.

[5]Mercury can be emitted in oxidized, elemental, or particulate-bound form.

[6]Sorbent injection systems inject sorbents—powdery substances, typically activated carbon, to which mercury binds—into the exhaust from boilers before it is emitted from the stack.

[7]In this report, the term "boiler configuration" refers to a coal-fired boiler's suite of air pollution control devices.

DOE's field tests met or exceeded program goals, the only way to truly know the effectiveness—and associated costs—of mercury control technologies is through their continuous operation in commercial applications at a variety of configurations. At least 18 states have laws or regulations requiring mercury emissions reductions at coal-fired power plants.[8] The compliance time frames for the state requirements vary. As of August 2009, five states—Connecticut, Delaware, Illinois, Massachusetts, and New Jersey—require compliance with mercury emission limits. In this context, you asked us to examine (1) what mercury reductions have been achieved by existing mercury control technologies and the extent to which they are being used at coal-fired power plants; (2) the costs associated with mercury control technologies currently in use; and (3) key issues EPA faces in developing a new regulation for mercury emissions from coal-fired power plants.

To respond to these objectives, we identified power plants with coal-fired boilers that are currently operating sorbent injection systems—the most mature, mercury-specific control technology—to reduce mercury emissions. Using a structured interview tool, we interviewed plant managers and engineers at the 14 coal-fired power plants operating sorbent injection systems to reduce mercury emissions. These individuals provided data on the effectiveness of sorbent injection systems at reducing mercury emissions and the costs of doing so.[9] We also obtained information on the engineering challenges plant officials have encountered in installing and operating sorbent injection systems and actions taken to mitigate those challenges.[10] In addition, we examined DOE National

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[8]Two of the states expect mercury emissions reductions from required installations of multipollutant control technologies; the other sixteen have specific mercury emissions reduction targets. These 18 states are those that had mercury emissions reduction requirements in place before the Clean Air Mercury Rule was promulgated or which promulgated state-specific provisions in addition to the provisions required by the rule and have not specifically repealed those provisions as of August 2009. GAO did not confirm whether each state is actively enforcing or planning to enforce these rules. Provisions of some state rules may rely on provisions of the Clean Air Mercury Rule, which have been vacated.

[9]We interviewed managers at plants with 24 of the 25 boilers using sorbent injection systems. As of August 2009, data for one boiler were not provided. Mercury emissions data for one boiler were being reviewed by the state clean air agency and were not provided in time for inclusion in this report.

[10]We visited six plants using sorbent injection systems, and we interviewed plant managers at six other plants that reported meeting state mercury emissions requirements with existing pollution control devices for other pollutants.

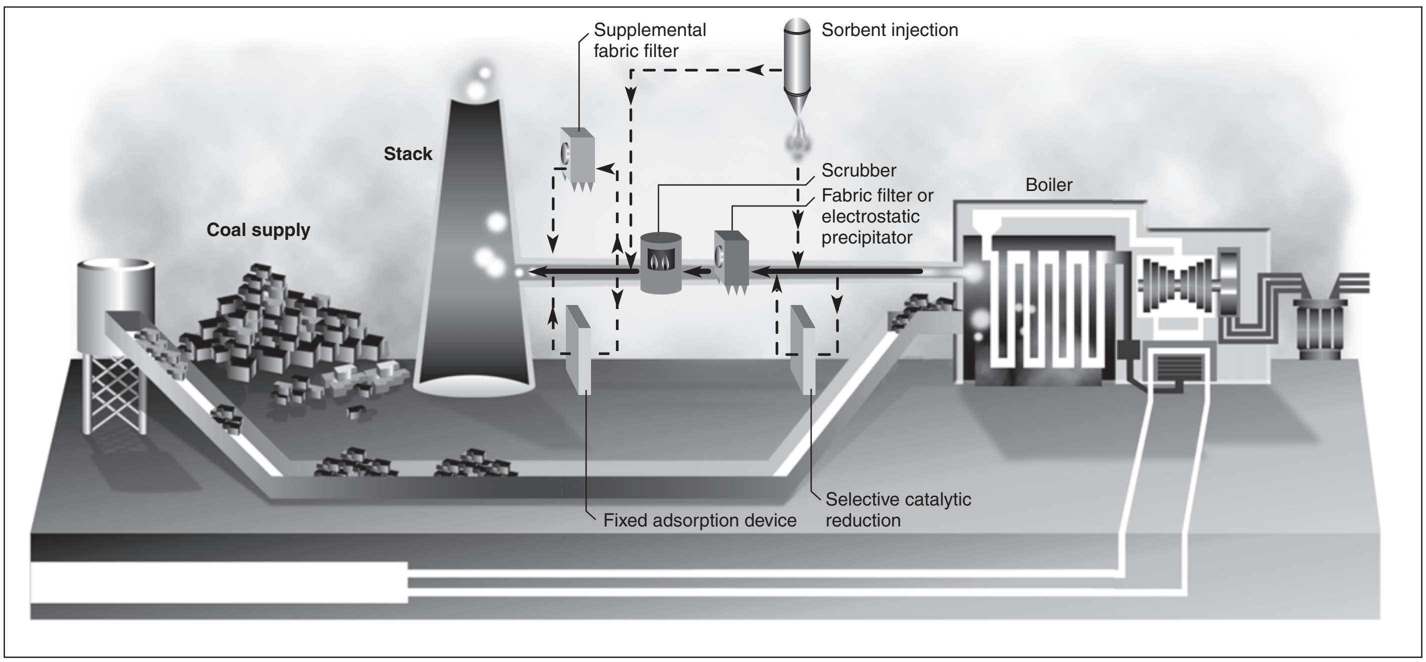
Energy Technology Lab, EPRI, and academic reports on the effectiveness and costs of sorbent injection systems over time and reviewed literature from recent technical conferences that addressed strategies to overcome challenges that some plants have experienced with sorbent injection systems. We also reviewed EPA's requirements for establishing MACT standards under the Clean Air Act and recent court cases with implications for how EPA establishes such standards. Finally, we met with EPA officials in the Office of Air and Radiation regarding the agency's plans for regulating mercury at power plants. Appendix I provides a more detailed description of our scope and methodology. We conducted this performance audit from November 2008 through September 2009 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

## Background

Mercury enters the environment in various ways, such as through volcanic activity, coal combustion, and chemical manufacturing. As a toxic element, mercury poses ecological threats when it enters water bodies, where small aquatic organisms convert it into its highly toxic form—methylmercury. This form of mercury may then migrate up the food chain as predator species consume the smaller organisms. Fish contaminated with methylmercury may pose health threats to people who rely on fish as part of their diet. Mercury can harm fetuses and cause neurological disorders in children, resulting in, among other things, impaired cognitive abilities. The Food and Drug Administration and EPA recommend that expectant or nursing mothers and young children avoid eating swordfish, king mackerel, shark, and tilefish and limit consumption of other potentially contaminated fish. These agencies also recommend checking local advisories about recreationally caught freshwater and saltwater fish. In recent years, most states have issued advisories informing the public that concentrations of mercury have been found in local fish at levels of public health concern.

Coal-fired power plants burn at least one of three primary coal types—bituminous, subbituminous, and lignite—and some plants burn a blend of these coals. Of all coal burned by power plants in the United States in 2004, DOE estimates that about 46 percent was bituminous, 46 percent was subbituminous, and 8 percent was lignite. The amount of mercury in coal and the relative ease of its removal depend on a number of factors, including the geographic location where it was mined and the chemical variation within and among coal types.[11] In addition to mercury, coal combustion releases other harmful air pollutants, including sulfur dioxide and nitrogen oxides. EPA regulates these pollutants under its program intended to control acid rain and its new source performance standards program. Figure 1 shows various pollution controls that may be used at coal-fired power plants: selective catalytic reduction to control nitrogen oxides, wet or dry scrubbers to reduce sulfur dioxide, fabric filters and hot-side or cold-side electrostatic precipitators to control particulate matter, and sorbent injection to reduce mercury emissions.

**Figure 1: Sample Layout of Air Pollution Controls, Including Sorbent Injection to Control Mercury, at a Coal-Fired Power Plant**




Source: GAO analysis of Electric Power Research Institute data.

[11]Coal combustion releases mercury in oxidized, elemental, or particulate-bound form. Oxidized mercury is more prevalent in the flue gas from bituminous coal combustion, and it is relatively easy to capture using some sulfur dioxide controls, such as wet scrubbers. Elemental mercury, more prevalent in the flue gas from combustion of lignite and subbituminous coal, is more difficult to capture with existing pollution controls. Particulate-bound mercury is relatively easy to capture in particulate matter control devices.

From 2000 to 2009, DOE's National Energy Technology Lab conducted field tests at operating power plants with different boiler configurations to develop mercury-specific control technologies capable of achieving high mercury emission reductions at the diverse fleet of U.S. coal-fired power plants.[12] As a result, DOE now has comprehensive information on the effectiveness of sorbent injection systems using all coal types at a wide variety of boiler configurations. Most of these tests were designed to achieve mercury reductions of 50 to 70 percent while decreasing costs—which consist primarily of the cost of the sorbent. Thus, the results from the DOE test program may understate the mercury reductions that can be achieved by sorbent injection systems to some extent. For example, while a number of short-term tests achieved mercury reductions in excess of 90 percent, the amount of sorbent injection that achieved the reductions was often decreased during long-term tests to determine the minimum cost of achieving, on average, 70 percent mercury emissions reductions.

Beginning in 2007—near the end of the research program—DOE field tests aimed to achieve reductions of 90 percent or greater mercury at low costs. However, DOE reported that federal funding for the DOE tests was eliminated before the final phase of planned tests was completed. Under its mercury testing program, DOE initially tested the effectiveness of untreated carbon sorbents, and then DOE tested the effectiveness of chemically treated sorbents. In addition, DOE assessed solutions to impacts on plant devices, structures, or operations that may result from operating these systems—called "balance-of-plant impacts." We note that DOE, EPRI, and others have also helped develop and test other technologies, including oxidation catalysts and precombustion mercury removal, to reduce mercury emissions that may become commercially available in the future. We provide information on some of these emerging technologies in appendix II.

[12]DOE's research program also tested different types of boilers (such as T-fired, wall-fired and cyclone); DOE officials said the pollution control devices were the more important parameter in mercury emissions reductions.

## Substantial Mercury Reductions Have Been Achieved Using Sorbent Injection Technology at 14 Plants and in Many DOE Tests

Power plants using sorbent injection systems—either commercially deployed or tested by DOE and industry—have achieved substantial mercury reductions with the three main types of coal and on boiler configurations that exist at nearly three-fourths of U.S. coal-fired power plants. Some plants, however, may require alternative strategies to achieve significant mercury emissions reductions. Nonetheless, some plants already achieve substantial mercury emissions reductions with existing control devices for other pollutants.

### Sorbent Injection Systems Have Achieved Substantial Mercury Emissions Reductions at Power Plants

The managers of 14 coal-fired power plants reported to us they currently operate sorbent injection systems on 25 boilers to meet the mercury emissions reduction requirements of five states and several consent decrees and construction permits. Data from power plants show that these boilers have achieved, on average, reductions in mercury emissions of about 90 percent.[13] Of note, all 25 boilers currently operating sorbent injection systems nationwide have met or surpassed their relevant regulatory mercury requirements, according to plant managers.[14] Following are a few examples:

- A 164 megawatt[15] bituminous-fired boiler, built in the 1960s and operating a cold-side electrostatic precipitator and wet scrubber, was reported as exceeding its 90 percent reduction requirement—achieving more than a 95 percent mercury emission reduction using chemically treated carbon sorbent.

[13]This number reflects data reported by officials with 9 boilers that were required to achieve 90 percent mercury emission reduction—which 7 surpassed—and 10 boilers that were required to achieve reductions between 80 percent and 89 percent. We do not have mercury emissions reduction data for 5 of the 24 sorbent injection systems because the power company running these systems is not required to measure emissions under its regulatory framework. Data for another boiler are being reviewed by the state clean air agency.

[14]Data from commercial applications of sorbent injection systems show that mercury reductions have been achieved over periods ranging from 3 months to more than a year. Most data we examined reflected mercury emissions as of the fourth quarter of 2008. Since that time, the power plants have continued to use sorbent injection systems—in some cases, these systems have been in continuous use for nearly 2 years.

[15]A megawatt is a unit for measuring the electric generation capacity of a power plant. One megawatt of capacity operating for one full day produces 24 megawatt-hours—or 24,000 kilowatt-hours—of electricity.

- A 400 megawatt subbituminous-fired boiler, built in the 1960s and operating a cold-side electrostatic precipitator and a fabric filter, was reported as achieving a 99 percent mercury reduction using untreated carbon sorbent, exceeding its 90 percent reduction regulatory requirement.

- A recently constructed 600 megawatt subbituminous-fired boiler operating a fabric filter, dry scrubber, and selective catalytic reduction system was reported as achieving an 85 percent mercury emission reduction using chemically treated carbon sorbent, exceeding its 83 percent reduction regulatory requirement.

While mercury emissions reductions achieved with sorbent injection on a particular boiler configuration do not guarantee similar results at other boilers with the same configuration,[16] the reductions achieved in deployments and tests provide important information for plant managers who must make decisions about pollution controls to reduce mercury emissions as more states' mercury regulations become effective and as EPA develops a national mercury regulation.[17] Further, in 2008, DOE reported that the high performance observed during many of its field tests at power plants with a variety of boiler configurations has given coal-fired power plant operators the confidence to begin deploying these technologies. The sorbent injection systems currently used at power plants to reduce mercury emissions are operating on boiler configurations that are used at 57 percent of U.S. coal-fired power boilers.[18] Further, when the results of 50 tests of sorbent injection systems at power plants conducted primarily as part of DOE's or EPRI's mercury control research and

[16]As we reported in 2005, the results achieved at a particular power plant may not necessarily serve as a reliable indicator of the performance of the same control devices at all plants. For example, some data show that the extent of mercury reduction achieved by sorbent injection at facilities using electrostatic precipitators depends largely on the location of these devices at the plant. The location of an electrostatic precipitator affects the temperatures of the flue gas entering the device, allowing more mercury to be captured at cooler temperatures.

[17]For example, see EPRI's 2006 *Mercury Control Technology Selection Guide*, which summarized tests by DOE and other organizations to provide the coal-fired power industry with a process to select the most promising mercury control technologies. EPRI assessed the applicability of technologies to various coal types and power plant configurations and developed decision trees to facilitate decision making.

[18]We used EPA's 2006 National Electric Energy Data System database for calculating the percentage of coal-fired boilers with particular configuration types. We excluded coal-fired boilers under 25 megawatts from our analysis because the Clean Air Act does not apply to smaller units such as these.

development programs are factored in, mercury reductions of at least 90 percent have been achieved at boiler configurations used at nearly three-fourths of coal-fired power boilers nationally.[19] Some boiler configurations tested in the DOE program that are not yet included in commercial deployments follow:

- A 360 megawatt subbituminous-fired boiler with a fabric filter and a dry scrubber using a chemically treated carbon sorbent achieved a 93 percent mercury reduction.

- A 220 megawatt boiler burning lignite, equipped with a cold-side electrostatic precipitator, increased mercury reduction from 58 percent to 90 percent by changing from a combination of untreated carbon sorbent and a boiler additive to a chemically treated carbon sorbent.

- A 565 megawatt subbituminous-fired boiler with a fabric filter achieved mercury reductions ranging from 95 percent to 98 percent by varying the amount of chemically treated carbon sorbent injected into the system.[20]

As these examples of commercially deployed and tested injection systems show, power plants are using chemically treated sorbents and sorbent enhancement additives, as well as untreated sorbents. Chemically treated sorbents and additives can help convert the more difficult-to-capture mercury common in lignite and subbituminous coals to a more easily captured form, which helped DOE and industry achieve high mercury reduction across all coal types.[21] The DOE test program initially used untreated sorbents. On the basis of these initial tests, we reported in 2005 that sorbent injection systems showed promising results but that they were not effective when used at boilers burning lignite and subbituminous

[19]We identified 56 field tests conducted by DOE during its mercury control technology testing program. Of these tests, we analyzed mercury reduction data of 41 tests conducted at power plants. The majority of these tests were long-term tests (30 days or more). Our analysis does not include mercury reduction data associated with the other 15 tests either because they reflected mercury reduction associated with mercury oxidation catalysts—an emerging mercury control technology—or because test result data were not reported. We also analyzed results of 9 tests conducted by industry, primarily by EPRI.

[20]The rate of sorbent injection varied between 1.0 pounds per million actual cubic feet and 3.0 pounds per million actual cubic feet.

[21]DOE injected sorbents that were treated with halogens such as chlorine or bromine, which help convert mercury from an elemental form into an oxidized form.

coals.[22] Since then, DOE's shift to testing chemically treated sorbents and enhancement additives showed that using chemically treated sorbents and enhancement additives could achieve substantial mercury reductions for coal types that had not achieved these results in earlier tests with untreated sorbents. For example, injecting untreated sorbents reduced mercury emissions by an average of 55 percent during a 2003 DOE test at a subbituminous-fired boiler. Recent DOE tests using chemically treated sorbents and enhancement additives, however, have resulted in average mercury reductions of 90 percent for boilers using subbituminous coals.[23] Similarly, recent tests on boilers using lignite reduced mercury emissions by about 80 percent, on average.

The examples of substantial mercury reductions highlighted above also show that sorbent injection can be successful with both types of air pollution control devices that power plants use to reduce emissions of particulate matter—electrostatic precipitators and fabric filters. In some commercial deployments, fabric filters were installed to assist with mercury control. Plant officials told us, for example, that they chose to install fabric filters to assist with mercury control for 10 of the sorbent injection systems currently deployed—but that some of the devices were installed primarily to comply with other air pollution control requirements. One plant manager, for example, said that the fabric filter installed at his plant has helped the sorbent injection system achieve higher levels of mercury emission reductions but that the driving force behind the fabric filter installation was compliance with particulate matter emission limits. Further, as another plant manager noted, fabric filters may provide additional benefits by limiting emissions of acid gases and trace metals, as well as by preserving fly ash—fine powder resulting from coal combustion—for sale for reuse.[24] Fabric filters, which are more effective at mercury emission reduction than electrostatic precipitators, are increasingly being installed to reduce emissions of particulate matter and other pollutants, but currently less than 20 percent of boilers have them.

[22]GAO, *Clean Air Act: Emerging Mercury Control Technologies Have Shown Promising Results, but Data on Long-Term Performance Are Limited*, GAO-05-612 (Washington, D.C.: May 31, 2005).

[23]On subbituminous coal units, eight long-term tests were conducted using chemically treated sorbents. The average mercury emission reduction was 90 percent, with mercury reductions ranging from 81 percent to 93 percent.

[24]Properties of fly ash vary significantly with coal composition and plant-operating conditions. Some power plants sell fly ash for use in Portland cement and to meet other construction needs.

The successful deployments of sorbent injection technologies at power plants occurred around the time DOE concluded, on the basis of its tests, that these technologies were ready for commercial deployment. As a result, funding for the DOE testing program has been eliminated.[25] As many states' compliance dates for mercury emission reduction near,[26] the Institute of Clean Air Companies reported that power plants had 121 sorbent injection systems on order as of February 2009.[27] (App. III provides data on state regulations requiring mercury emission reductions.)

## Some Plants May Require Alternative Strategies to Achieve Significant Mercury Reductions

While sorbent injection technology has been shown to be effective with all coal types and on boiler configurations that currently exist at more than three-fourths of U.S. coal-fired power plants, DOE tests show that some plants may not be able to achieve mercury reductions of 90 percent or more with sorbent injection systems alone. Following are a few reasons why:

- Sulfur trioxide—which can form under certain operating conditions or from using high sulfur bituminous coal—may limit mercury reduction because it interferes with the process of mercury binding to carbon sorbents.
- Hot-side electrostatic precipitators reduce the effectiveness of sorbent injection systems. Installed on 6 percent of boilers nationwide, these particulate matter control devices operate at very high temperatures, which reduces the ability of mercury to bind to sorbents and be collected in the devices.
- Lignite, used by roughly 3 percent of boilers nationwide,[28] has relatively high levels of elemental mercury—the most difficult form to capture.

[25]The DOE mercury testing program has not received new funding since fiscal year 2008.

[26]Illinois, Maryland, Minnesota, Montana, New Mexico, New York, and Wisconsin require compliance by the end of 2010. Arizona, Colorado, New Hampshire, Oregon, and Utah require compliance in 2012 or later. Georgia and North Carolina require installation between 2008 and 2018 of other pollution control devices that capture sulfur dioxide, nitrogen oxides, and mercury as a side benefit. North Carolina requires the submission of specific mercury reduction plans for certain plants by 2013.

[27]The Institute of Clean Air Companies is the trade association of companies that supply air pollution control and monitoring technology.

[28]As noted earlier, the lignite burned by all coal-fired power plants represents 8 percent of all coal burned in the United States.

Lignite is found primarily in North Dakota and the Gulf Coast (the latter is called Texas lignite). Mercury reduction using chemically treated sorbents and sorbent enhancement additives on North Dakota lignite has averaged about 75 percent—less than reductions using bituminous and subbituminous coals. Less is known about Texas lignite because few tests have been performed using it. However, a recent test at a plant burning Texas lignite achieved an 82 percent mercury reduction.

Boilers that may not be able to achieve 90 percent emissions reductions with sorbent injection alone, and some promising solutions to the challenges they pose, are discussed in appendix IV. Further, EPRI is continuing research on mercury controls at power plants that should help to address these challenges. In some cases, however, plants may need to pursue a strategy other than sorbent injection to achieve high mercury reductions. For example, officials at one plant decided to install a sulfur dioxide scrubber—designed to reduce both mercury and sulfur dioxide—after sorbent injection was found to be ineffective. This approach may become more typical as power plants comply with the Clean Air Interstate Rule and court-ordered revisions to it,[29] which EPA is currently developing, and as some plants add air pollution control technologies required under consent decrees.

Along these lines, EPA air strategies group officials told us that many power plants will be installing devices—fabric filters, scrubbers, and selective catalytic reduction systems—that are typically associated with high levels of mercury reduction, which will likely reduce the number of plants requiring alternative strategies for mercury control. Finally, mercury controls have been tested on about 90 percent of the boiler configurations at coal-fired power plants. The remaining 10 percent include several with devices that are often associated with high levels of mercury emission reductions, such as selective catalytic reduction devices for nitrogen oxides control and wet scrubbers for sulfur dioxide control.

[29]The Clean Air Interstate Rule is a regional air pollution reduction program covering 28 eastern states and the District of Columbia. Developed by EPA and promulgated in May 2005, the rule controls emissions from power plants through caps on sulfur dioxide and nitrogen oxides pollution. A D.C. Circuit Court of Appeals December 23, 2008, ruling leaves this rule and its trading programs in place until EPA issues a new rule to replace it. EPA informed the Court that development and finalization of a replacement rule could take about 2 years.

## A Number of Plants Already Achieve Substantial Mercury Reductions with Existing Controls for Other Pollutants

Importantly, mercury control technologies will not have to be installed on a number of coal-fired boilers to meet mercury emission reduction requirements because these boilers already achieve high mercury reductions from their existing pollution control devices.[30] EPA 1999 data, the most recent available, indicated that about one-fourth of the industry achieved mercury reductions of 90 percent or more as a co-benefit of other pollution control devices.[31] We found that of the 36 boilers currently subject to mercury regulation, 11 are relying on existing pollution controls to meet their mercury reduction requirements.[32] One plant manager told us his plant achieves 95 percent mercury reduction as a result of existing devices, specifically with a fabric filter for particulate matter control, a scrubber for sulfur dioxide control, and a selective catalytic reduction system for nitrogen oxides control. Other plants may also be able to achieve high mercury reduction with their existing pollution control devices. For example, according to EPA data, a bituminous-fired boiler with a fabric filter may reduce mercury emissions by more than 90 percent. As discussed above, it is likely that many power plants will be installing devices that are typically associated with high levels of mercury reduction; thus the number of plants that may not require sorbent injection systems to meet regulatory requirements is likely to increase.

[30]Nationwide, mercury reductions achieved as a co-benefit of other pollution control devices reduced mercury emissions from about 75 tons (inlet coal) to approximately 48 tons. Mercury reductions achieved as a co-benefit range from zero to nearly 100 percent, depending on control device configuration and coal type. For example, a boiler using bituminous coal and having a fabric filter can achieve mercury reductions in excess of 90 percent. In contrast, a boiler using subbituminous coal and having only a cold-side electrostatic precipitator might achieve little, if any, co-benefit mercury reduction.

[31]This estimate is based on data from EPA's 1999 information collection request, which EPA air toxics program officials believe to be representative of the current coal-fired power industry.

[32]Two plants with four boilers will face increasingly stringent limits in the next 3 to 4 years. One plant manager, facing a mercury reduction requirement that will increase from 80 percent to 90 percent, told us that the plant is currently installing a sorbent injection system in anticipation of the more stringent standard. The other plant manager, facing a mercury reduction requirement that will increase from 85 percent to 95 percent, told us that his plant will likely need to install a sorbent injection system in the future to supplement the co-benefit mercury capture the plant currently achieves with existing pollution controls.

## Mercury Control Technologies Are Often Relatively Inexpensive, but Costs Depend Largely on How Plants Comply with Requirements for Reducing Other Pollutants

The cost to meet current regulatory requirements for mercury reductions has varied depending in large part on decisions regarding compliance with other pollution reduction requirements. For example, while sorbent injection systems alone have been installed on most boilers that must meet mercury reduction requirements—at a fraction of the cost of other pollution control devices—fabric filters have also been installed on some boilers to assist in mercury capture or to comply with particulate matter requirements, according to plant officials we interviewed.

The costs of purchasing and installing sorbent injection systems and monitoring equipment have averaged about $3.6 million for the 14 coal-fired boilers that use sorbent injection systems alone to reduce mercury emissions.[33] For these boilers, the cost ranged from $1.2 million to $6.2 million.[34] By comparison, on the basis of EPA estimates, the average cost to purchase and install a wet scrubber for sulfur dioxide control, absent monitoring system costs, is $86.4 million per boiler, ranging from $32.6 million to $137.1 million.[35] EPA's estimate of the cost to purchase and install a selective catalytic reduction device to control nitrogen oxides ranges from $12.7 million to $127.1 million, or an average of $66.1 million.

Capital costs can increase significantly if fabric filters are also purchased to assist in mercury emission reductions or as part of broader emission reduction requirements. For example, plants installed fabric filters at another 10 boilers for these purposes. On the five boilers where plant officials reported also installing a fabric filter specifically designed to assist the sorbent injection system in mercury emission reductions, the average reported capital cost for both the sorbent injection system and fabric filter was $15.8 million per boiler—the costs ranged from $12.7 million to $24.5 million. Importantly, some of these boilers have uncommon configurations[36]—ones that, as discussed earlier, DOE tests

[33]Cost data are reported in 2008 dollars.

[34]The total cost to purchase and install a sorbent injection system reflects the costs of (1) sorbent injection equipment, (2) an associated mercury emissions monitoring system, and (3) associated engineering and consulting services.

[35]EPA's 2006 cost estimates are reported in 2008 dollars.

[36]Three of the five boilers with fabric filters designed specifically to assist in mercury reduction, for instance, have hot-side electrostatic precipitators—a relatively rare particulate matter control device that inhibits high mercury removal when sorbent injection systems are used without fabric filters.

showed would need additional control devices to achieve high mercury reductions.[37]

For the five boilers where plant officials reported installing fabric filters along with sorbent injection systems largely to comply with requirements to control other forms of air pollution, the average reported capital cost for the two technologies was $105.9 million per boiler, ranging from $38.2 million to $156.2 million per boiler.[38] For these boilers, the capital costs result from requirements to control other pollutants, and we did not determine what portion of these costs would appropriately be allocated to the cost of reducing mercury emissions. Decisions to purchase such fabric filters will likely be driven by the broader regulatory landscape affecting plants in the near future, such as requirements for particulate matter and sulfur dioxide reductions, as well as EPA's upcoming MACT standard to regulate mercury emissions from coal-fired power plants. Information on detailed average costs to purchase and install sorbent injection systems and monitoring equipment, with and without fabric filters, is provided in appendix V.

Regarding operating costs, plant managers said that annual operating costs associated with sorbent injection systems consist almost entirely of the cost of the sorbent itself. In operating sorbent injection systems, sorbent is injected continuously into the boiler exhaust gas to bind to mercury passing through the gas. The rate of injection is related to, among other things, the level of mercury emissions reduction required to meet regulatory requirements and the amount of mercury in the coal used. For the 18 boilers with sorbent injection systems for which power plants provided sorbent cost data, the average annualized cost of sorbent was $674,000—ranging from $76,500 to $2.4 million.

Plant engineers often adjust the injection rate of the sorbent to capture more or less mercury—the more sorbent in the exhaust gas, the higher the likelihood that more mercury will bind to it. Some plant managers told us that they have recently been able to decrease their sorbent injection rates,

[37]The costs reported by officials of coal-fired power plants that installed sorbent injection systems and, in some cases, fabric filters may not necessarily serve as reliable indicators of the costs of the same control devices at all plants.

[38]The average cost of the sorbent injection system for these boilers was $2.9 million and for the monitoring systems, $500,000. The average cost for the fabric filters was $84 million and for the engineering studies, $11 million.

thereby reducing costs, while still complying with relevant requirements. Specifically, a recently constructed plant burning subbituminous coal successfully used sorbent enhancement additives to considerably reduce its rate of sorbent injection—resulting in significant savings in operating costs when compared with its original expectations. Plant managers at other plants reported that they have injected sorbent at relatively higher rates because of regulatory requirements that mandate a specific injection rate. In one state, for example, plants are required to operate their sorbent injection systems at an injection rate of 5 pounds per million actual cubic feet.[39] Among the 19 boilers for which plant managers provided operating cost data, the average injection rate was 4 pounds per million actual cubic feet; rates ranged from 0.5 to 11.0 pounds per million actual cubic feet.

For those plants that installed a sorbent injection system alone to meet mercury emissions requirements—at an average cost of $3.6 million—the cost to purchase, install, and operate sorbent injection and monitoring systems represents 0.12 cents per kilowatt hour, or a potential 97 cent increase in the average residential consumer's monthly electricity bill. How, when, and to what extent consumers' electric bills will reflect the capital and operating costs power companies incur for mercury controls depends in large measure on market conditions and the regulatory framework in which the plants operate. Power companies in the United States are generally divided into two broad categories: (1) those that operate in traditionally regulated jurisdictions where cost-based rate setting still applies (rate-regulated) and (2) those that operate in jurisdictions where companies compete to sell electricity at prices that are largely determined by supply and demand (deregulated). Rate-regulated power companies are generally allowed by regulators to set rates that will recover allowable costs, including a return on invested capital.[40] Minnesota, for example, passed a law in 2006 allowing power companies to seek regulatory approval for recovering the costs of state-required reductions in mercury emissions in advance of the regulatory schedule for rate increase requests. One power company in the state submitted a plan for the installation of sorbent injection systems to reduce mercury

[39]Pounds per million actual cubic feet is the standard metric for measuring the rate at which sorbent is injected into a boiler's exhaust gas.

[40]Under traditional cost-based rate regulations, utility companies submit to regulators the costs they seek to cover through the rates they charge their customers. Regulators examine the power companies' requests and decide what costs are allowable under the relevant rules.

emissions at two of its plants at a cost of $4.4 million and $4.5 million, respectively, estimating a rate increase of 6 to 10 cents per month for customers of both plants.[41]

For power companies operating in competitive markets where wholesale electricity prices are not regulated, prices are largely determined by supply and demand. Generally speaking, market pricing does not guarantee full cost recovery to suppliers, especially in the short run. Of the 25 boilers using sorbent injection systems to comply with a requirement to control mercury emissions, 21 are in jurisdictions where full cost recovery is not guaranteed through regulated rates.

In addition to the costs discussed above, some plant managers told us they have incurred costs associated with balance-of-plant impacts. The issue of particular concern relates to fly ash—fine particulate ash resulting from coal combustion that some power plants sell for commercial uses, including concrete production, or donate for such uses as backfill. According to DOE, about 30 percent of the fly ash generated by coal-fired power plants was sold in 2005; 216 plants sold some portion of their fly ash. Most sorbents increase the carbon content of fly ash, which may render it unsuitable for some commercial uses.[42] Specifically, some plant managers told us that they have lost income because of lost fly ash sales due to its carbon content and incurred additional costs to store fly ash that was previously either sold or donated for re-use. For the eight boilers with installed sorbent injection systems to meet mercury emissions requirements for which plants reported actual or estimated fly-ash-related costs, the average net cost reported by plants was $1.1 million per year.[43]

[41]The rate increase request will be submitted in conjunction with requests for rate increases for the utility's other plants.

[42]Technologies to mitigate balance-of-plant costs associated with fly ash are available. For example, one plant installed a polishing fabric filter using TOXECON™ system, which preserves the plant's ability to sell its fly ash. Another plant had previously installed an ash reduction device that removes excess carbon in fly ash and enables the plant to sell the vast majority of its fly ash when operating its sorbent injection system.

[43]DOE's research program also examined the potential costs plants may incur to dispose of fly ash if the carbon and mercury content renders it unsuitable for commercial uses. See Andrew P. Jones et al., *DOE/NETL's Phase II Mercury Control Technology Field Testing Program: Updated Economic Analysis of Activated Carbon Injection*, prepared at the request of DOE, May 2007.

Advances in sorbent technologies that have reduced costs at some plants also offer the potential to preserve the market value of fly ash. For example, at least one manufacturer offers a concrete-friendly sorbent to help preserve fly ash sales—thus reducing potential fly ash storage and disposal costs. Additionally, a recently constructed plant burning subbituminous coal reported that it had successfully used sorbent enhancement additives to reduce its rate of sorbent injection from 2 pounds to less than one-half pound per million actual cubic feet—resulting in significant savings in operating costs and enabling it to preserve the quality of its fly ash for reuse. Other potential advances include refining sorbents through milling and changing the sorbent injection sites. Specifically, in testing, milling sorbents has, for some configurations, improved their efficiency in reducing mercury emissions—that is, reduced the amount of sorbent needed—and also helped minimize negative impact on fly ash re-use. Also, in testing, some vendors have found that injecting sorbents on the hot side of air preheaters can decrease the amount of sorbent needed to achieve desired levels of mercury control.[44]

In addition, some plant managers reported balance-of-plant impacts associated with sorbent injection systems, such as ductwork corrosion and small fires in the particulate matter control devices. The managers told us these issues were generally minor and have been resolved. For example, two plants experienced corrosion in the ductwork following the installation of their sorbent injection systems. One plant manager resolved the problem by purchasing replacement parts at a cost of $4,500. The other plant manager told us that the corrosion problem remains unresolved but that it is primarily a minor engineering challenge that does not impact plant operations. Four plant managers reported fires in the particulate matter control devices; plant engineers have generally solved this problem by emptying the ash from the collection devices more frequently. Overall, despite minor balance-of-plant impacts, most plant managers said that the sorbent injection systems at their plants are more effective than they had originally expected.

[44]An air preheater is a device designed to preheat the combustion air used in a fuel-burning furnace for the purpose of increasing the thermal efficiency of the furnace.

## Decisions EPA Faces on Key Regulatory Issues Will Have Implications for the Effectiveness of Its Mercury Emission Standard for Coal-Fired Power Plants and the Availability of Monitoring Data

EPA's decisions on key regulatory issues will impact the overall stringency of its MACT standard regulating mercury emissions. Specifically, the data EPA decides to use will affect (1) the mercury emission reductions calculated for "best performers," from which a proposed emission limit is derived; (2) whether EPA will establish varying standards for the three coal types; and (3) how EPA's standard will take into account varying operating conditions. Each of these issues will affect the stringency of the MACT standard the agency proposes. In addition, the format of the standard—whether it limits the mercury emissions as a function of the amount of mercury per trillion British thermal units (BTU) of heat input (an input standard) or on the basis of the amount of mercury per megawatt hour of electricity produced (an output standard)—may affect the stringency of the MACT standard the agency proposes. Finally, the court's decision to vacate the Clean Air Mercury Rule, which required most coal-fired power plants to conduct continuous emissions monitoring for mercury beginning in 2009, has delayed for a number of years the continuous emissions monitoring that would have started in 2009 at most coal-fired power plants.

### Current Data from Commercial Deployments and DOE Tests Could Be Used in Determining Whether to Support a More Stringent Standard for Mercury Emissions from Power Plants Than Was Last Proposed by EPA

Obtaining data on mercury emissions and identifying the "best performers"—defined as the 12 percent of coal-fired power plant boilers with the lowest mercury emissions[45]—is a critical initial step in the development of a MACT standard regulating mercury emissions. EPA may set one standard for all power plants, or it may establish subcategories to distinguish among classes, types, and sizes of plants. For example, in its 2004 proposed mercury MACT standard,[46] EPA established subcategories for the types of coal most commonly used by power plants. Once the average mercury emissions of the best performers are established for power plants—or for subcategories of power plants—EPA accounts for variability in the emissions of the best performers in its MACT standards. EPA's method for accounting for variability has generally resulted in MACT standards that are less stringent than the average emission reductions achieved by the best performers.

[45]This is how section 112 of the Clean Air Act, as amended, defines best performers for the largest categories of sources when establishing MACT standards.

[46]Prior to finalizing the Clean Air Mercury Rule, EPA also proposed a MACT standard regulating mercury emissions from coal-fired power plants. EPA chose not to finalize the MACT rule.

To identify the best performers, EPA typically collects emissions data from a sample of plants representative of the U.S. coal-fired power industry through a process known as an information collection request. Before a federal agency can collect data from 10 or more nongovernmental parties, such as power plants, it must obtain approval from the Office of Management and Budget (OMB) for the information collection request. According to EPA officials, this data collection process typically takes from 8 months to 1 year. Although EPA has discretion in choosing the data it will use to identify best performers,[47] on July 2, 2009, EPA published a draft information collection request in the *Federal Register* providing a 60-day public comment period on the draft questionnaire to industry prior to submitting this information collection request to OMB for review and approval. EPA's schedule for issuing a proposed rule and a final rule has not yet been established; the agency is currently defending a lawsuit that may establish such a schedule.[48]

Our analysis of EPA's 1999 data, as well as more current data from deployments and DOE tests, shows that newer data may have several implications for the stringency of the standard. First, the average emissions reductions of the best performers, from which the standard is derived, may be greater using more current data than the reductions derived from EPA's 1999 data. Our analysis of EPA's 1999 data shows an average mercury emission reduction of nearly 91 percent for the best performers.[49] In contrast, using more current commercial deployment and DOE test data, as well as data on co-benefit mercury reductions collected in 1999, an average mercury emission reduction of nearly 96 percent for best performers is demonstrated. The 1999 data do not reflect the significant and widespread mercury reductions achieved by sorbent injection systems. Further, EPA's 2004 proposed MACT standards for mercury were substantially less stringent than the 1999 average emission

[47]EPA officials told us, for instance, that the agency could decide to use data from its 1999 information collection request or data from commercial deployments and DOE tests.

[48]Under the Clean Air Act Amendments of 1990, EPA had 10 years from the enactment of the amendments, or 2 years from the listing of electric steam-generating units as sources of hazardous air pollutants subject to regulation, whichever was later, to promulgate a MACT standard. Because EPA did not list electric steam-generating units until 2000, it originally had 2 years, or until 2002, to promulgate a MACT standard. Because EPA missed this promulgation date, a mandatory duty lawsuit was filed against the agency that will result in a court-approved schedule.

[49]Our analysis of EPA's data includes the three primary coal types: bituminous, subbituminous, and lignite.

reduction of the best performers because of variability in mercury emissions among the top performers, as discussed later in more detail.

Second, more current information that reflects mercury control deployments and DOE tests may make the rationale EPA used in the past to create MACT standards for different subcategories less compelling to the agency now. In 2004, using 1999 data, EPA proposed separate MACT standards for each type of coal used at power plants. The agency explained that mercury emissions reductions from boilers using lignite and subbituminous coal was substantially less than from those using bituminous coal. Specifically, the 1999 data EPA used for its 2004 proposed MACT standards showed that best performers achieved average emission reductions of 97 percent for bituminous, 71 percent for subbituminous, and 45 percent for lignite. In contrast, more current data show that sorbent injection systems have achieved average mercury emissions reductions of more than 90 percent with bituminous and subbituminous coal types and nearly this amount with lignite.

Finally, using more current emissions data in setting the MACT standard for regulating mercury may mean that accounting for variability in emissions will not have as significant an effect as it did in the 2004 proposed MACT—when it led to a less stringent MACT standard—because more current data may already reflect variability. In its 2004 proposed MACT, EPA explained that its 1999 data, obtained from the average of short-term tests (three samples taken over a 1- to 2-day period), did not necessarily reveal the range of emissions that would be found over extended periods of time or under a full range of operating conditions they could reasonably anticipate. EPA thus extrapolated longer-term variability data from the short-term data, and on the basis of these calculations, proposed MACT standards equivalent to a 76 percent reduction in mercury emissions for bituminous coal, a 25 percent reduction for lignite, and a 5 percent reduction for subbituminous coal—20 to 66 percentage points lower than the average of what the best performers achieved for each coal type.

However, current data may eliminate the need for such extrapolation. Data from commercial applications of sorbent injection systems, DOE field tests, and co-benefit mercury reductions show that mercury emissions reductions well in excess of 90 percent have been achieved over periods ranging from more than 30 days in field tests to more than a year in commercial applications. Mercury emissions measured over these periods may more accurately reflect the variability in mercury emissions that plants would encounter over the range of operating conditions.[50] Along these lines, at least 15 states with mercury emission limits require long-term averaging—ranging from 1 month to 1 year—to account for variability. According to the manager of a power plant operating a sorbent injection system, long-term averaging of mercury emissions takes into account the "dramatic swings" in mercury emissions from coal that may occur. He told us that while mercury emissions can vary on a day-to-day basis, this plant has achieved 94 percent mercury reduction, on average, over the last year.[51] Similarly, another manager of a power plant operating a sorbent injection system told us the amount of mercury in the coal used at the plant "varies widely, even from the same mine." Nonetheless, the plant manager reported that this plant achieves its required 85 percent mercury reduction because the state allows averaging mercury emissions on a monthly basis to take into account the natural variability of mercury in the coal.

## The Type of Standard EPA Chooses May Also Affect the Stringency of the Regulation

In 2004, EPA's proposed mercury MACT included two types of standards to limit mercury emissions: (1) an output-based standard for new coal-fired power plants and (2) a choice between an input- or output-based standard for existing plants. Input-based standards establish emission limits on the basis of pounds of mercury per trillion BTUs of heat input; output-based standards, on the other hand, often establish emission limits

[50]According to officials with one industry group, many coal-fired power plants use coal from numerous mines, and the mercury content in coal from these different sources can vary dramatically. These officials said that variability in mercury emissions resulting from the use of coal from different sources should be considered when setting a MACT standard. Officials with several coal-fired power plants told us that requiring compliance over long time periods—such as monthly, quarterly, or annually—is one way to ensure that such variability is accounted for.

[51]The requirement for this plant, which the plant manager reported it has met, is for a 90 percent reduction averaged over a 3-month period.

on the basis of pounds of mercury per megawatt hour of electricity produced. These standards are referred to as emission limits.[52]

Input-based limits can have some advantages for coal-fired power plants. For example, input-based limits can provide more flexibility to older, less efficient plants because they allow boilers to burn as much coal as needed to produce a given amount of electricity, as long as the amount of mercury per trillion BTUs does not exceed the level specified by the standard.[53] However, input-based limits may allow some power plants to emit more mercury per megawatt hour than output-based limits. Under an output-based standard, mercury emissions cannot exceed a specific level per megawatt-hour of electricity produced—efficient boilers that use less coal will be able to produce more electricity than inefficient boilers under an output-based standard. Moreover, under an output-based limit, less efficient boilers may have to, for example, increase boiler efficiency or switch to a lower mercury coal. Thus, output-based limits provide a regulatory incentive to enhance both operating efficiency and mercury emission reductions. If all else was held equal, less mercury would be emitted nationwide under an output-based standard.

We found that at least 16 states have established a format for regulating mercury emissions from coal-fired power plants. Eight states allow plants to meet either an emission limit or a percent reduction, three require an emission limit, four require percent reductions, and one state requires plants to achieve whatever mercury emissions reductions—percent

[52]For the purposes of setting a standard, emissions limits can be correlated to percent reductions. For example, EPA's 2004 proposed standards for bituminous, lignite, and subbituminous coal (2, 9.2, and 5.8 pounds per trillion BTUs, respectively) are equivalent with mercury emissions reductions of 76, 25, and 5 percent, respectively, based on nationwide averages of the mercury content in coal. During EPA's 2004 MACT development process, state and local agency stakeholders, as well as environmental stakeholders, generally supported output-based emission limits; industry stakeholders generally supported having a choice between an emission limit and a percent reduction. EPA must now decide in what format it will set its mercury MACT standard(s).

[53]The main types of coal burned, in decreasing order of rank, are bituminous, subbituminous, and lignite. Rank is the coal classification system based on factors such as the heating value of the coal. High-rank coal generally has relatively high heating values (i.e., heat per unit of mass when burned) compared with low-rank coal, which has relatively low heating values.

reduction or emission limit—are greater.[54] On the basis of our review of these varying regulatory formats, we conclude that to be meaningful, a standard specifying a percent reduction should be correlated to an emission limit. When used alone, percent reduction standards may reduce the actual mercury emissions reductions achieved. For example, in one state, mercury reductions are measured against the "historical" amount of mercury in coal, rather than the amount of mercury in coal being currently used by power plants in the state. If plants are required to reduce mercury by, for example, 90 percent compared to historical coal data, but coal used in the past had higher levels of mercury than the plants have been using more recently, then actual mercury emission reductions would be less than 90 percent. In addition, percent reduction requirements do not provide an incentive for plants burning high mercury coal to switch coals or pursue more effective mercury control strategies because it is easier to achieve a percent reduction requirement with higher mercury coal than with lower mercury coals.

Similarly, a combination standard that gives regulated entities the option to choose either a specified emission limit or a percent reduction might reduce the actual mercury emission reductions achieved. For example, a plant burning coal with a mercury content of 15 pounds per trillion BTUs that may choose between meeting an emission limit of 0.7 pounds of mercury per trillion BTUs or a 90 percent reduction could achieve the percent reduction while emitting twice the mercury that would be allowed under the specified emission limit. As discussed earlier, for the purposes of setting a standard, a required emission limit that provides a consistent benchmark for plants to meet can be correlated to a percent reduction. For example, according to EPA's Utility Air Toxic MACT working group, a 90 percent mercury reduction based on national averages of mercury in coal generally equates to a national average emission limit of approximately 0.7 pounds per trillion BTUs.[55] For bituminous coal, a 90

[54]Colorado, Connecticut, Delaware, Illinois, Massachusetts, New Jersey, Oregon, and Utah allow either an emission limit or a percent reduction; Montana, New Mexico, and New York require an emission limit; Maryland, Minnesota, New Hampshire, and Wisconsin require percent reductions (Wisconsin mercury emission standard changes to require meeting either a limit or a percent reduction in 2015); and Arizona requires the more stringent option—whichever is more stringent, a percent reduction or emission limit.

[55]Presentation on "Recommendations on the Utility Air Toxics MACT, Final Working Group Report, October 2002." The Working Group on the Utility MACT was formed under the Clean Air Act Advisory Committee, Subcommittee for Permits/New Source Reviews/Toxics.

percent reduction equates to a limit of 0.8 pounds per trillion BTUs; for subbituminous coal, a 90 percent reduction equates to a limit of 0.6 pounds per trillion BTUs; and for lignite, a 90 percent reduction equates to a limit of 1.2 pounds per trillion BTUs.

## Continuous Monitoring of Mercury Emissions at Most Power Plants Has Been Delayed

EPA's now-vacated Clean Air Mercury Rule required most coal-fired power plants to conduct continuous emissions monitoring for mercury—and a small percentage of plants with low mercury emissions to conduct periodic testing—beginning in 2009. State and federal government and nongovernmental organization stakeholders told us they support reinstating the monitoring requirements of the Clean Air Mercury Rule. In fact, in a June 2, 2008, letter to EPA, the National Association of Clean Air Agencies requested that EPA reinstate the mercury monitoring provisions that were vacated in February 2008 because, among other things, they are important to state agencies with mercury reduction requirements and power plants complying with them.[56] This association also said the need for federal continuous emissions monitoring requirements is especially important in states that cannot adopt air quality regulations more stringent than those of the federal government. However, EPA officials told us the agency has not determined how to reinstate continuous emissions monitoring requirements for mercury at coal-fired power plants outside of the MACT rulemaking process.

Under the Clean Air Mercury Rule, the selected monitoring methodology for each power plant was to be approved by EPA through a certification process. For its part, EPA was to develop performance specifications—protocols for quality control and assurance—for continuous emissions monitoring systems (CEMS). However, when the Clean Air Mercury Rule was vacated in February 2008, EPA delayed development of these performance specifications. EPA has taken steps recently to develop performance specifications for mercury CEMS under a May 6, 2009, proposed rule limiting mercury emissions from facilities that produce Portland cement.[57] As part of this proposed rule, EPA also proposed performance specifications that describe performance evaluations that must be conducted to ensure the continued accuracy of the CEMS

[56]The National Association of Clean Air Agencies represents air pollution control agencies in 53 states and territories and over 165 major metropolitan areas across the United States.

[57]Portland cement is the most common type of cement in general use around the world. It is a basic ingredient of concrete, mortar, stucco and most non-specialty grout.

emissions data. In the proposed rule, EPA stated that the performance specifications for mercury CEMS used to monitor emissions from Portland cement facilities could also apply to other sources. Further, an EPA Sector Policies and Programs Division official told us that if EPA chooses—as it did in its 2004 proposed MACT—to require continuous monitoring for mercury emissions in its final rule regulating hazardous air pollutants from coal-fired power plants, the performance specifications will already be in place for continuous emissions monitoring systems' use when the Portland cement MACT is finalized.

Effective continuous emissions monitoring can assist facilities and regulators ensure compliance with regulations and can also help facilities identify ways to better understand the efficiency of their processes and operations. For example, using CEMS, plant managers told us they can routinely make adjustments in the amount of sorbent needed to meet regulatory requirements, potentially reducing costs. Nevertheless, monitoring mercury emissions is more complex than monitoring other pollutants, such as nitrogen oxides and sulfur dioxide, which are measured in parts per million—mercury is emitted at lower levels of concentration than other pollutants and is measured in parts per billion. Consequently, mercury CEMS may require more time to install than CEMS for other pollutants, and according to plant engineers using them, getting these relatively complex monitoring systems up and running properly involves a steeper learning curve.

In our work, we found that mercury CEMS were installed on 16 boilers at power plants and used for monitoring operations and compliance reporting.[58] Plant managers reported that their mercury CEMS were online from 62 percent to 99 percent of the time. The system that was online 62 percent of the time was not used for compliance purposes but rather to monitor the effectiveness of different sorbent injection rates on mercury emissions. Excluding this case, CEMS were online about 90 percent of the time, on average. When these systems were offline, it was mainly because of failed system integrity checks or for routine parts replacement. Some plant engineers told us that they believed CEMS were several years away from commercial readiness to accurately measure mercury emissions but that they had purchased and installed the CEMS in anticipation of the requirement that was part of the now-vacated Clean Air Mercury Rule.

[58]At least 15 states have enacted mercury emission standards that include a continuous emission or other long-term monitoring requirement

Others using CEMS said that these systems are accurate at measuring mercury emissions and can be used to determine compliance with a stringent regulation.

EPA, EPRI, the National Institute of Standards and Technology, and others are working collaboratively to approve protocols for quality assurance and control for mercury CEMS that will ensure the continued accuracy of the emissions data at the precise levels of many state rules. These organizations are in the final phase of their collaborative effort, and in July 2009 they provided interim procedures to states that require use of mercury CEMS and other groups that use these systems.

## Concluding Observations

Data from commercially deployed sorbent injection systems show that substantial mercury emissions reductions have been achieved at a relatively low cost. Importantly, these results, along with test results from DOE's comprehensive research and development program, suggest that similar reductions can likely be achieved at most coal-fired power plants in the United States. Other strategies, including blending coal and using other technologies, exist for the small number of plants with configuration types that were not able to achieve significant mercury emissions reductions with sorbent injection alone.

Whether power plants will install sorbent injection systems or pursue multipollutant control strategies will likely be driven by the broader regulatory context in which they operate, such as requirements for sulfur dioxide and nitrogen oxides reductions in addition to mercury, and the associated costs to comply with all pollution reduction requirements. Nonetheless, for many plants, sorbent injection systems appear to be a cost-effective technology for reducing mercury emissions. For other plants, sorbent injection may represent a relatively inexpensive bridging technology—that is, one that is available for immediate use to reduce only mercury emissions but that may be phased out—over time—with the addition of multipollutant controls, which are more costly. Moreover, some plants achieve substantial mercury emissions reductions without mercury-specific controls because their existing controls for other air pollutants also effectively reduce mercury emissions. In fact, while many power plants currently subject to mercury regulation have installed sorbent injection systems to achieve required reductions, about one-third of them are relying on existing pollution control devices to meet the requirements.

As EPA proceeds with its rulemaking process to regulate hazardous air pollutants from coal-fired power plants, including mercury, it may find that current data from commercially deployed sorbent injection systems and plants that achieve high co-benefit mercury reductions would support a more stringent mercury emission standard than was last proposed in 2004. More significant mercury emissions reductions are actually being achieved by the current best performers than was the case in 1999 when such information was last collected—and similar results can likely be achieved by most plants across the country at relatively low cost.

## Agency Comments and Our Evaluation

We provided a draft of this report to the Administrator, EPA, and the Secretary, DOE, for review and comment. EPA and DOE provided technical comments, which we incorporated as appropriate.

We are sending copies of this report to interested congressional committees; the Administrator, the Environmental Protection Agency; the Secretary, Department of Energy; and other interested parties. The report is also available at no charge on the GAO Web site at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3841 or stephensonj@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made major contributions to this report are listed in appendix VI.

Sincerely yours,

John B. Stephenson
Director, Natural Resources
and Environment

# Appendix I: Objectives, Scope, and Methodology

This appendix details the methods we used to examine (1) the mercury reductions that have been achieved by existing mercury control technologies and the extent to which they are being used at coal-fired power plants, (2) the costs associated with mercury control technologies currently in use, and (3) key issues the Environmental Protection Agency (EPA) faces in developing a new regulation for mercury emissions from coal-fired power plants.

For the first two objectives, we identified coal-fired power plants subject to regulatory requirements to reduce mercury emissions by contacting clean air agencies in all 50 states. In so doing, we identified those states that had established laws or regulations—or had coal-fired power plants subject to consent decrees or construction permits—requiring reductions in mercury emissions. In states where laws or regulations are in effect, we asked clean air agency officials to identify which coal-fired power plants are meeting the requirements—either through "co-benefit" mercury removal achieved by plants' existing air pollution control equipment or by operating sorbent injection systems. State clean air agency officials identified 14 coal-fired power plants that are currently operating sorbent injection systems to meet regulatory requirements to reduce mercury emissions.[1] For these plants, we developed a structured interview instrument to obtain information on the effectiveness of sorbent injection systems in reducing mercury emissions and the associated costs of the systems and the monitoring equipment.[2] We designed the instrument to also obtain information on the engineering challenges, if any, that plant officials experienced when operating the systems and the steps taken to mitigate such challenges. Staff involved in the evaluation and development of mercury control technologies within EPA's Office of Research and

[1]Representatives of one plant that is operating a sorbent injection system to meet its state's mercury reduction requirements did not participate in the structured interview, stating they could not participate until a compliance report had been completed and submitted to the state clean air agency.

[2]We obtained data on the capital and operating costs incurred to purchase, install, and operate sorbent injection systems and determined their potential impact on utility rates. To account for differences in timing, we adjusted these costs for inflation to represent 2008 dollars. We then used, by boiler, the reported operating costs, total electrical output, and capital costs to determine a levelized cost per kilowatt hour. The levelized cost is an assessment of the anticipated costs of a sorbent injection system over its lifetime, including capital costs and operations and maintenance costs. We assumed a 20-year lifetime and a return on capital of 10 percent. We then compared these costs with DOE data on 2008 average utility rates by state to determine the potential impact on utility rates, should the plants we interviewed pass on 100 percent of the costs to consumers.

Development and DOE's Office of Fossil Energy reviewed and commented on the instrument. We conducted the structured interview with representatives of 13 of the 14 coal-fired power plants and conducted site visits at 6 of them. We conducted structured interviews with officials at the following plants:

- B.L. England, New Jersey
- Brayton Point, Massachusetts
- Bridgeport Harbor, Connecticut
- Crawford, Illinois
- Fisk, Illinois
- Indian River Generating Station, Delaware
- Mercer Generating Station, New Jersey
- Presque Isle, Michigan
- TS Power Plant, Nevada
- Vermillion Power Station, Illinois
- Walter Scott Jr. Energy Center, Iowa
- Waukegan, Illinois
- Weston, Wisconsin

Furthermore, state clean air agency officials identified six coal-fired power plants that are aiming to meet mercury emission reduction requirements through operation of existing air pollution control equipment. From officials with these six plants, we obtained information on the effectiveness of the existing controls in reducing mercury emissions, as well as the reliability and costs of mercury emissions monitoring equipment. We spoke with officials at the following plants:

- AES Thames, Connecticut
- Carney's Point, New Jersey
- Deepwater, New Jersey

- EdgeMoor, Delaware
- Logan, New Jersey
- Salem Harbor, Massachusetts

In addition to examining the effectiveness of commercially deployed sorbent injection systems, we examined field test results of sorbent injection systems—installed at operating power plants—conducted by DOE and the Electric Power Research Institute (EPRI) over the past 10 years as part of DOE's comprehensive mercury control technology test program. We relied primarily on data from the second and third phases of the DOE field testing program. The second phase of the DOE program focused heavily on chemically treated sorbents, which helped many boiler configurations achieve much higher mercury emission reductions than the same boiler configurations achieved under phase one tests, when untreated sorbents were used. The third phase of the DOE program focused on finding solutions to "balance-of-plant" impacts. To determine the percentage of coal-fired boilers nationwide that have air pollution control device configurations that are the same as those at power plants with commercially deployed sorbent injection systems or where field tests occurred, we used a draft version of EPA's National Electricity and Energy Data System database that contains boiler level data, as of 2006, on coal type used, pollution control devices installed, and generating capacity.[3]

We conducted a reliability review of the data we received from coal-fired power plants, EPA, and DOE. Through our review, we determined that the data were sufficiently reliable for our purposes. Our assessment consisted of interviews with officials about the data systems and elements of data. We also corroborated the data with other sources, where possible. For example, we verified the information in structured interviews by obtaining compliance reports from state clean air agencies, where possible. Finally, we reviewed literature presented at the 2008 MEGA Symposium and the 2009 Energy and Environment Conference on (1) strategies to overcome challenges that some plants have experienced with sorbent injection systems, such as sulfur trioxide interference, and (2) on emerging mercury control technologies, such as oxidation catalysts.

[3]We excluded boilers with generating capacity of less than 25 megawatts from our analysis because they would not be subject to a MACT regulation under the Clean Air Act.

For the third objective, we examined EPA's requirements for establishing MACT standards under the Clean Air Act and recent court cases with implications for how EPA establishes such standards.[4] We interviewed EPA officials in the Clean Air Markets Division and Sector Policies and Programs Division regarding the agency's plans for regulating mercury at power plants. To examine EPA's process for identifying best performers, we obtained and analyzed EPA data on mercury emissions reductions from the agency's 1999 information collection request. Using these data, we followed the steps EPA described in its proposed 2004 MACT rulemaking to calculate the average mercury emissions reductions achieved by the best performing 12 percent of boilers—the threshold for calculating a minimum MACT emissions standard under the Clean Air Act. We then used newer data—the data we obtained from commercially deployed sorbent injection systems and DOE and industry tests—and followed the same steps to calculate the average mercury emissions reductions achieved by the best performing 12 percent of these boilers.

In addition, we examined EPA's steps to resolve technical monitoring challenges, including how the agency develops quality control and assurance procedures for continuous emissions monitoring systems. We also obtained data from coal-fired power plants—operating 16 continuous emissions monitoring systems—on the reliability of the systems, including data on the number of times the systems were offline, the outcome of periodic system integrity checks, and the extent to which plant engineers believed the systems to accurately measure mercury emissions. We interviewed EPA's technical experts in the Clean Air Markets Division.

We conducted this performance audit from November 2008 through September 2009 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

[4]We examined the following cases: *National Lime Association v. EPA*, 233 F.3d 625 (D.C. Cir. 2000); *Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855 (D.C. Cir. 2001); *Sierra Club v. EPA*, 479 F.3d 875 (D.C. Cir. 2007); *Natural Resources Defense Council v. EPA*, 489 F.3d 1250 (D.C. Cir. 2007); *Natural Resources Defense Council v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007).

# Appendix II: Emerging Technologies That May Reduce Mercury Emissions from Coal-Fired Power Plants

In addition to sorbent injection systems, DOE, EPRI, and others have developed and tested other technologies to reduce mercury emissions that show promise and may become commercially available in the future. These technologies are being developed to potentially lower the cost of mercury removal for some plants and enable others—those for which sorbent injection may be ineffective—to achieve significant mercury emission reductions. Such technologies include oxidation catalysts, which help convert elemental mercury into oxidized mercury that can be captured in particulate control devices; the MerCAP™ process, which involves installing metal plates with sorbents on them in the exhaust gas (instead of injecting sorbents); and low-temperature mercury capture, which involves lowering the temperature of the exhaust gas to enable mercury to bind more effectively to the unburned carbon in fly ash. Finally, novel technologies are being developed by entities such as the Western Research Institute.[1] The technologies the Western Research Institute is working on include those designed to remove mercury directly from coal before it is burned. Innovative techniques for mercury control could eventually replace or augment the more mature technologies discussed in this report, according to DOE.

*Oxidation catalysts.* Oxidation catalysts are powdered chemicals injected into either the boiler or the boiler's exhaust gas to help change elemental mercury into oxidized mercury—a form that is easier to capture in pollution control devices for sulfur dioxide and particulate matter. According to recent research, oxidation of elemental mercury, which is then collected in particulate matter control devices or absorbed across a wet scrubber system, has the potential to be a reliable and cost-effective mercury control strategy for some coal-fired power plants, especially those that must comply with sulfur dioxide emission requirements. According to DOE, examples of oxidation catalysts tested at operating power plants include the following:

- URS Corporation tested oxidation catalysts at a plant that fires a blend of Texas lignite and subbituminous coals. Tests completed in April 2005 showed that oxidation catalysts enabled the wet scrubber to achieve mercury reductions ranging from 76 percent to 87 percent, compared with only 36 percent reduction under baseline conditions.

[1]The Western Research Institute is a not-for-profit research organization involved in advanced energy systems, environmental technologies, and highway materials research.

- URS has also begun testing oxidation catalysts at a boiler firing low-sulfur eastern bituminous coal that is equipped with a cold-side electrostatic precipitator. According to DOE, the project represents the next logical advancement of the catalytic oxidation technology, and it will answer technical questions such how much catalyst is required to achieve high mercury oxidation percentages, what is the catalyst life, and what is the efficiency of mercury capture in wet scrubber systems using oxidation catalysts.

*MerCAP™:* Developed by EPRI, MerCAP is a process in which metal plates laced with carbon sorbents are positioned in a boiler's exhaust gas stream to adsorb mercury. During two 6-month tests, MerCAP was used at a boiler equipped with a dry scrubber and a fabric filter and at another boiler equipped with a wet scrubber. After more than 250 days of continuous operation at one plant, mercury reduction averaged 30 percent to 35 percent across acid-treated MerCAP plates and 10 to 30 percent across the untreated plates. At the other plant, MerCAP achieved 15 percent mercury reduction when a water wash system for the plates was installed, which helped prevent limestone slurry from the wet scrubber system from inhibiting mercury reduction. MerCAP™ is still in the research and development phase, and although these mercury reduction amounts appear relatively low, when engineers altered the spacing between the metal plates, mercury emission reductions increased to about 60 percent in some cases.

*Low-temperature mercury capture process:* The low temperature mercury capture process helps reduce mercury emissions by cooling the exhaust gas temperature to about 220° Fahrenheit, which promotes mercury adsorption to the unburned carbon inherent in fly ash. This process may have the ability to reduce mercury emissions by over 90 percent, as was recently shown by one company performing a limited scale test.

*Pilot testing of novel mercury control technology:* The Western Research Institute is developing and evaluating the removal of mercury from coal prior to combustion. The institute developed a two-step process that involves first evaporating moisture in the coal and then heating the coal with inert gas. Pre-combustion mercury removal technology has been successful in removing 75 percent of mercury from subbituminous coal and 60 percent of mercury from lignite coal, but the technology has encountered difficulty when used with bituminous coal. By removing up to 75 percent of mercury before combustion, less mercury remains in the exhaust gas for removal by pollution control devices. In addition, pre-combustion technology has other benefits: (1) removing the moisture from the coal increases the heat content of the coal for combustion purposes, which may reduce the amount of coal burned by the plant and increase efficiency by about 3 percent; (2) this process also helps to remove other trace metals; (3) the water that is removed from the coal during pre-combustion treatment can be recovered and re-used in plant operations. According to DOE, Western Research Institute testing has also shown that, for some coals, the amount of time the coal is exposed to heat affects the amount of mercury removed. For example, an increase of 8 minutes of "residence time" resulted in the removal of nearly 80 percent of mercury before combustion.[2]

*DOE in-house development of novel control technologies:* DOE recently patented three techniques that are now licensed and in commercial demonstration. First, the thief carbon process—which involves extracting carbon from the boiler and using it as sorbent to inject into the exhaust gas for mercury capture—may be a cost-effective alternative to sorbent injection systems for mercury removal from boilers' exhaust gas. Thief carbon sorbents, for instance, range from $90 to $200 per ton according to DOE—less than 10 percent of the typical cost of sorbents used in sorbent injection systems. According to the Western Research Institute, which tested the thief carbon process at an operating power plant, mercury emission reductions were comparable to those achieved by commercially available sorbents. Second, DOE patented the photochemical oxidation process. This process introduces an ultraviolet light into the exhaust gas to help convert mercury to an oxidized form for collection in other pollution control devices.[3] Finally, DOE researchers have invented a new sorbent that works at elevated temperatures. The new sorbent, which is palladium-based, removes mercury at temperatures above 500° Fahrenheit and, according to DOE, may improve the overall energy efficiency of the combustion process.[4]

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[2]During testing, the percentage of mercury removed from coal varied from 50 percent to almost 90 percent, depending on the amount of time the coal was exposed to heat and inert gas, according to DOE.

[3]Researchers at DOE's National Energy Technology Laboratory received the 2005 Award for Excellence in Technology Transfer from the Federal Laboratory Consortium for the photochemical oxidation method.

[4]Researchers at DOE's National Energy Technology Laboratory received the 2008 Award for Excellence in Technology Transfer for developing the palladium-based sorbent.

# Appendix III: Summary of State Regulations Requiring Reductions in Mercury Emissions from Coal-Fired Power Plants

Table 1 summarizes data about state regulations that require reductions in mercury emissions from coal-fired power plants, including compliance date, percent reduction required, and emission limit. This table represents the best available data on state regulations, which appear to be independent of rules that were adopted in accordance with the vacated Clean Air Mercury Rule as of August 2009. For states with percent reduction and emission limit provisions, plants generally may choose the format with which they will comply.

**Table 1: Summary of Key Provisions of State Regulations Requiring Mercury Emission Reductions Applicable to Existing or All Coal-Fired Power Plants**

| State | Compliance date | Percent reduction | Emission limit | Continuous emission or other long-term monitoring requirement (some state requirements may rely on vacated portions of federal rule) |
|---|---|---|---|---|
| Arizona[a] | December 31, 2013 | 90 | 0.0087 pounds/gigawatt-hour | X |
| Colorado[a] | July 1, 2014[b] | 80 | 0.0174 pounds/gigawatt-hour | X |
| | January 1, 2018 | 90 | 0.0087 pounds/gigawatt-hour | |
| Connecticut[a] | July 1, 2008 | 90 | 0.60 pounds/trillion BTUs | |
| Delaware[c] | January 1, 2009 | 80 | 1.0 pounds/trillion BTUs | X |
| | January 1, 2013 | 90 | 0.60 pounds/trillion BTUs | |
| Georgia | Each plant shall install certain types of air pollution control devices, at varying times, according to a legislatively prescribed schedule. | | | |
| Illinois[a, d] | July 1, 2009 | 90 | 0.0080 pounds/gigawatt-hour | X |
| Maryland | January 1, 2010 | 80 | No emission limit required | X |
| | January 1, 2013 | 90 | No emission limit required | |
| Massachusetts | January 1, 2008 | 85 | 0.0075 pounds/gigawatt-hour | X |
| | October 1, 2012 | 95 | 0.0025 pounds/gigawatt-hour | |
| Minnesota[a] | December 31, 2010[e] | 90 | No emission limit required | X |
| | December 31, 2014[f] | 90 | No emission limit required | |
| Montana[a] | January 1, 2010 | No percent reduction required | 0.90 pounds/trillion BTUs[g] | X |
| New Hampshire[a] | July 1, 2013 | 80 | No emission limit required | X |
| New Mexico | January 1, 2010/ January 1, 2018 | No percent reduction required | Each plant has its own emission limit (in two phases) | X |
| New Jersey | December 15, 2007 | 90 | 3 milligrams/megawatt-hour | |

| State | Compliance date | Percent reduction | Emission limit | Continuous emission or other long-term monitoring requirement (some state requirements may rely on vacated portions of federal rule) |
|---|---|---|---|---|
| New York | January 1, 2010[h] | No percent reduction required | 0.60 pounds/trillion BTUs | X |
| North Carolina[i] | December 31, 2013 | No percent reduction required | No emission limit required | X |
| Oregon[a] | July 1, 2012 | 90 | 0.60 pounds/trillion BTUs | X |
| Utah[a] | December 31, 2012 | 90 | 0.65 pounds/trillion BTUs | X |
| Wisconsin | January 1, 2010[j] | 40 | No emission limit required | X |
| | January 1, 2015[k] | 90 | 0.0080 pounds/gigawatt-hour | |

Source: GAO analysis of state clean air agency data.

[a]Alternate standards may be applied under certain circumstances.

[b]Two plants in Colorado must comply with an 80 percent mercury emission reduction requirement beginning on January 1, 2012.

[c]Requirement applies to large plants. Plants are also subject to mass emission caps beginning in 2009 and becoming more stringent in 2013.

[d]Through 2013, requirement applies to systems of plants and additional minimum requirements apply on a plant-by-plant basis; after 2013, requirement applies to all plants on a plant-by-plant basis.

[e]This compliance date applies to coal-fired boilers equipped with dry scrubbers for air emissions control.

[f]This compliance date applies to coal-fired boilers equipped with wet scrubbers for air emissions conrol.

[g]The Montana regulation established a separate standard for coal-fired boilers using lignite of 1.5 pounds per gigawatt-hour.

[h]Between 2010 and 2015, 13 coal-fired power plants must reach a specific mercury emission limit prescribed by law. If a plant is not on that list, it must achieve an emission limit of 0.60 pounds per trillion BTUs. Beginning in 2015, all plants must achieve an emission limit of 0.60 pounds per trillion BTUs.

[i]North Carolina requires installation of technology that captures sulfur dioxide, nitrogen oxides, and mercury.

[j]Applies to four major utilities.

[k]Applies to large coal-fired power plants. Plants can take an additional six years to achieve 90% reduction if they choose additional nitrogen oxide and sulfur dioxide controls. Small coal-fired power plants must reduce their mercury emissions to that achieved by the Best Available Control Technology by January 1, 2015.

# Appendix IV: Potential Solutions for Plants Unable to Achieve High Mercury Emissions Reductions Using Sorbent Injection Systems Alone

DOE tests show that some plants may not be able to achieve mercury emissions reductions of 90 percent or more with sorbent injections alone. Specifically, the tests identified three factors that can impact the effectiveness of sorbent injection systems: sulfur trioxide interference, using hot-side precipitators, and using lignite. These factors are discussed below, along with some promising solutions to the challenges they pose.

*Sulfur trioxide interference.* High levels of sulfur trioxide gas may limit mercury emission reductions by preventing some mercury from binding to carbon sorbents. Using an alkali injection system in conjunction with sorbent injection can effectively lessen sulfur trioxide interference. Depending on the cause of the sulfur trioxide interference—which can stem from using a flue gas conditioning system, a selective catalytic reduction system, or high-sulfur bituminous coal—additional strategies may be available to ensure high mercury reductions:

- Flue gas conditioning systems, used on 13 percent of boilers nationwide, improve the performance of electrostatic precipitators by injecting a conditioning agent, typically sulfur trioxide, into the flue gas to make the gas more conducive to capture in electrostatic precipitators. Mercury control technology vendors are working to develop alternative conditioning agents to improve the performance of electrostatic precipitators without jeopardizing mercury emission reductions using sorbent injection.

- Selective catalytic reduction systems, common control devices for nitrogen oxides, are used by about 20 percent of boilers nationwide. Although selective catalytic reduction systems often improve mercury capture, in some instances these devices may lead to sulfur trioxide interference when sulfur in the coal is converted to sulfur trioxide gas. Newer selective catalytic reduction systems often have improved catalytic controls, which can minimize the conversion of sulfur to sulfur trioxide gas.

- High-sulfur bituminous coal—defined as having a sulfur content of at least 1.7 percent sulfur by weight—may also lead to sulfur trioxide interference in some cases. As many as 20 percent of boilers nationwide may use high-sulfur coal, according to 2005 DOE data; however, the number of coal boilers using high-sulfur bituminous coal is likely to decline as more stringent sulfur dioxide regulations take effect. Plants can consider using alkali-based sorbents, such as Trona, which adsorb sulfur trioxide gas before it can interfere with the performance of sorbent injection systems. Plants that burn high-sulfur coal can also consider blending their fuel to include some portion of low-sulfur coal. In addition, according to EPA, power companies are likely to install scrubbers for controlling sulfur dioxide at plants burning high-sulfur coal (for those boilers that do not already have them). Scrubbers also reduce mercury emissions as a co-benefit, so many such plants may use them instead of sorbent injection systems to achieve mercury emissions reductions.

*Hot-side electrostatic precipitators.* Installed on 6 percent of boilers nationwide, these particulate matter control devices operate at very high temperatures, which reduces the amount of mercury binding to sorbents for collection in particulate matter control devices. However, at least two promising techniques for increasing mercury capture have been identified in tests and commercial deployments at configuration types with hot-side electrostatic precipitators. First, during DOE testing 70 percent mercury emission reductions were achieved with specialized heat-resistant sorbents. Moreover, one of the 25 boilers currently using a sorbent injection system has a hot-side electrostatic precipitator and uses a heat-resistant sorbent. Although plant officials are not currently measuring mercury emissions for this boiler, the plant will soon be required to achieve mercury emission reductions equivalent to 90 percent.[1] Second, in another DOE test, three 90 megawatt boilers—each with a hot-side electrostatic precipitator—achieved more than 90 percent mercury emission reductions by installing a shared fabric filter in addition to a sorbent injection system, a system called TOXECON™. According to plant officials, these three units, which are using this system to comply with a consent decree, achieved 94 percent mercury emission reductions during the third quarter of 2008, the most recent compliance reporting period during which the boiler was operating under normal conditions.

*Lignite.* North Dakota and Texas lignite, the fuel source for roughly 3 percent of boilers nationwide, have relatively high levels of elemental mercury—the most difficult form to capture. Four long-term DOE tests were conducted at coal units burning North Dakota lignite using chemically treated sorbents. Mercury emission reductions averaged 75 percent across the tests. The best result was achieved at a 450 megawatt boiler with a fabric filter and a dry scrubber—mercury reductions of 92 percent were achieved when chemically treated sorbents were used. In addition, two long-term tests were conducted at plants burning Texas lignite with a 30 percent blend of subbituminous coal. With coal blending,

[1]Plant officials did not provide us with mercury emission reduction data for this boiler.

these boilers achieved average mercury emission reductions of 82 percent. Specifically, one boiler, with an electrostatic precipitator and a wet scrubber, achieved mercury reductions in excess of 90 percent when burning the blended fuel. The second boiler achieved 74 percent reductions in long-term testing. However, 90 percent was achieved in short-term tests using a higher sorbent injection rate. Although DOE conducted no tests on plants burning purely Texas lignite, one power company is currently conducting sorbent injection tests at a plant burning 100 percent Texas lignite and is achieving promising results. In the most recent round of testing, this boiler achieved mercury emission reduction of 82 percent using untreated carbon and a boiler additive in conjunction with the existing electrostatic precipitator and wet scrubber.

# Appendix V: Average Costs to Purchase and Install Sorbent Injection Systems and Monitoring Equipment, with and without Fabric Filters, per Boiler

Table 2 summarizes information on average costs to purchase and install sorbent injection systems and monitoring equipment, with and without fabric filters. This table includes cost data for boilers with sorbent injection systems and fabric filters installed specifically for mercury emissions control. This table does not include cost data for the 5 boilers with sorbent injection systems and fabric filters that were installed largely to comply with requirements to control other forms of air pollution.[1]

**Table 2: Detailed Average Costs to Purchase and Install Sorbent Injection Systems and Monitoring Equipment, with and without Fabric Filters, per Boiler**

2008 dollars

| Mercury control technology type | Number of boilers using technology type[a] | Cost of sorbent injection system | Cost of mercury emissions monitoring system | Cost of consulting and engineering | Cost of fabric filter | Total |
|---|---|---|---|---|---|---|
| Sorbent injection system alone | 14 | $2,723,000[b] | $560,000[b] | $382,000[b] | [c] | **$3,594,000**[d] |
| Sorbent injection system with fabric filter to assist in mercury removal | 5 | $1,335,000[e] | $120,000[f] | $1,444,000[g] | $19,010,000[h] | **$15,786,000**[i] |

Source: GAO analysis of data from power plants operating sorbent injection systems.

[a]We identified 25 boilers using sorbent injection systems to reduce mercury emissions, for which power companies provided cost data on 24. Cost data for 19 of the 24 are provided in the table. We did not report costs in this table for the remaining 5 because much of the cost incurred for fabric filters in these cases is not related to mercury removal. See footnote.

[b]Of the 14 boilers that installed a sorbent injection system alone, cost data for only 12 boilers were provided in this category.

[c]Not applicable.

[d]Numbers do not add to total. Total capital cost data were provided for 14 boilers, but for only 12 in the other cost categories.

[e]Cost data were provided for two boilers in this category. The costs of the sorbent injection systems for the two boilers were $1,071,000 and $1,599,000.

[f]Cost data were provided for two boilers in this category. The costs of the monitoring systems for the two boilers were $107,000 and $160,000.

[g]Cost data were provided for three boilers in this category and were the same for all three boilers.

[h]Cost data were provided for two boilers in this category. The costs of the fabric filters were $15,255,000 and $22,765,000.

[i]Numbers do not add to total. Total capital cost data were provided for five boilers with fabric filters.

[1]For the five boilers where plant officials reported installing fabric filters along with sorbent injection systems largely to comply with requirements to control other forms of air pollution, the average reported capital cost for the two technologies was $105.9 million per boiler, ranging from $38.2 million to $156.2 million per boiler.[1] For these boilers, the capital costs result from requirements to control other pollutants, and we did not determine what portion of these costs would appropriately be allocated to the cost of reducing mercury emissions.

# Appendix VI: GAO Contact and Staff Acknowledgments

## GAO Contact

John B. Stephenson, (202) 512-3841 or stephensonj@gao.gov

## Staff Acknowledgments

In addition to the contact named above, Christine Fishkin, Assistant Director; Nathan Anderson; Mark Braza; Antoinette Capaccio; Nancy Crothers; Michael Derr; Philip Farah; Mick Ray; and Katy Trenholme made key contributions to this report.

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Attachment C

# Coal Ash Tonage: Subcommittee Districts

ENERGY COMMERCE COMMITTEE'S SUBCOMMITEE ON ENERGY POWER, U.S. HOUSE OF REPRESENTATIVES

| Rep. | Site Name | Coal Ash | Company | Hazard Potential* | Year Commissioned | Unit | Damage Case** |
|---|---|---|---|---|---|---|---|
| Ed Whitfield (R) | *HMP&L Station Two Henderson* | 316.4 thousand tons | | | | | |
| | *DB Wilson* | 644.4 thousand tons | | | | | |
| | *Green River* | 30.6 thousand tons | Kentucky Utilities Co. | None | 1949 | Ash Pond #2 | |
| | *Paradise* | 125.7 thousand tons | Tennessee Valley Authority | Low | 1967 | Fly Ash Extension Area Pond | |
| | *Shawnee* | 305.7 thousand tons | Tennessee Valley Authority | Significant | 1952 | Ash Pond | |
| | **Total** | **1.423 million tons** | | | | | |
| John Shimkus (R) | *Kincaid Generation LLC* | 108.7 thousand tons | Dominion | None | 1967 | Kincaid Slagfield Berm | |
| | *Newton* | 117 thousand tons | Ameren Energy Generating Co | None | 1977 | Primary Ash Pond | |
| | **Total** | **0.226 million tons** | | | | | |
| Terry Lee (R) | *North Omaha* | **15 thousand tons** | Omaha Public Power District | | | | |
| Pete Olson (R) | *WA Parish* | **0.199 million tons** | NRG Texas Power, LLC | None | 1978 | Air Preheater Pond | |
| David McKinley (R) | *Kammer* | 48.7 thousand tons | American Electric Power | None | 1963 | | |
| | *Mitchell* | 452.5 thousand tons | American Electric Power | Significant | 1975 | | |
| | *PPG Natrium Plant* | 98.4 thousand tons | | | | | |
| | *Pleasants Power Station* | 294 thousand tons | Allegheny Energy Supply Co | High | 1978 | McElroy's Run Embankment | |
| | *Harrison Power Station* | 1.390 million tons | | | | | |
| | *Rivesville* | 19.9 thousand tons | | | | | |
| | *Albright* | 78 thousand tons | | | | | |
| | *Mt Storm* | 1.0405 million tons | | | | | |
| | **Total** | **3.422 million tons** | | | | | |
| Cory Gardner (R) | *Pawnee* | 11.15 thousand tons | Xcel Energy | None | Late 1970's | Ash Disposal Facility (ADF) | |
| | *Rawhide* | 59.9 thousand tons | Platte River Power Authority | None | 1984 | North Bottom Ash Transfer Pond | |
| | **Total** | **71.05 thousand tons** | | | | | |
| Joe Barton (R) | *Big Brown* | 335.6 thousand tons | | | | | |
| | *Limestone* | 1374.4 thousand tons | NRG Texas Pwer, LLC | None | 1985 | Bottom Ash Cooling Pond | |
| | **Total** | **1.710 million tons** | | | | | |
| Bobby Rush (D) | *Fisk Street* | **9.1 thousand tons** | | | | | |
| Jim Matheson (D) | *Carbon* | 70 thousand tons | | | | | |
| | *Huntington* | 478 thousand tons | | | | | |
| | *Hunter* | 597 thousand tons | | | | | |
| | *Bonanza* | 330.2 thousand tons | | | | | |
| | *Navajo* | 372.55 thousand tons | | | | | |
| | **Total** | **1.848 million tons** | | | | | |
| John Dingell (D) | *Trenton Channel* | 139 thousand tons | | | | | |
| | *Monroe* | 603 thousand tons | Detroit Edison Co | None | early 1970's | Bottom Ash Basin | |
| | *JR Whiting* | 42.2 thousand tons | Consumers Energy Co | None-Low | 1952-79 | Ponds 1-6 | |
| | **Total** | **0.784 million tons** | | | | | |
| Charles Gonzalez (D | *JT Deely* | **4.1 thousand tons** | | | | | YES; "interdeminate" |

## Coal Ash Tonage: Subcommittee Districts

ENERGY COMMERCE COMMITTEE'S SUBCOMMITEE ON ENERGY POWER, U.S. HOUSE OF REPRESENTATIVES

| **Sites Within 5 miles of District Borders** | | | | | | | |
|---|---|---|---|---|---|---|---|
| John Sullivan (R) | *Northeastern Plant* | 36.8 thousand tons | American Electric Power | None | 1980 | Bottom Ash Pond | |
| | *GRDA* | 89.5 thousand tons | | | | | |
| | *Muskogee Mill* | 29.8 thousand tons | | | | | YES, but rejected for insufficient information |
| | *Muskogee* | 51.5 thousand tons | | | | | |
| | **Total** | **0.208 million tons** | | | | | |
| John Shimkus (R) | *Marion* | 502.4 thousand tons | | | | | |
| | *Coffeen* | 90 thousand tons | Ameren Energy Generating Co | None | 1979 | Recycle Pond | YES, determined a potential damage case; exceeded levels of sulfate, total dissolved solids and manganese |
| | *White, Brewer Ash Land* | data not available | | | | | |
| | *AB Brown* | 369.95 thousand tons | Vectren | Significant | 1978 | Lower Dam | YES |
| | **Total** | **0.962 million tons** | | | | | |
| Terry Lee (R) | *Council Bluffs* | 104.5 thousand tons | | | | | |
| | *Lon Wright* | 16.8 thousand tons | | | | | |
| | **Total** | **0.121 million tons** | | | | | |
| Cory Gardner (R) | *Valmont* | **58.6 thousand tons** | Xcel Energy | None | 1993 | Coal Pile Stormwater Runoff Pond | |
| Michael Doyle (D) | *Reliant Elrama Power Plant* | data not available | | | | | YES, Potential damage case; exceeded level of cadmium |

**NOTES**

*Members of the Subcommittee that do not have sites in or near their districts are not listed.*

**This column lists the hazard potential determination made by EPA subsequent to the responses it received to Information Requests (IR) sent out in March, April and December of 2009. EPA received responses covering 228 facilities and 629 surface impoundments and similar management units. Of the 228 facilities that responded, 200 units (32 percent) have been given a hazard potential rating using the National Inventory of Dams criteria. Of the 200 units that have been rated, 50 units (25 percent) are rated as High Hazard Potential; 71 units (36 percent) are rated as Significant Hazard Potential; 71 units (36 percent) are rated as Low Hazard Potential; and 8 units (4 percent) are rated as Less than Low Hazard Potential. 429 units (68 percent) have not received a hazard potential rating. The hazard potential ratings do not assess the stability of these units; the ratings assess the potential for loss of life or environmental and economic damage. Units rated as High Potential Hazard are those where failure will probably cause loss of life. See www.epa.gov/epawaste/nonhaz/industrial/special/fossil/surveys/*

***This column lists whether the site was the subject of a damage case assessment, which were done for 59 cases in which public interest groups alleged damage to human health or the environment in 1999. See Cal Combustion Waste Damage Case Assesments, U.S. Envt'l Protection Agency, Office of Solid Waste (July 9, 2007), available at see http://www.publicintegrity.org/assets/pdf/CoalAsh-Doc1.pdf*