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CLEAN AIR ACT

Preliminary Observations on the Effectiveness and Costs of Mercury Control Technologies at Coal-Fired Power Plants

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Highlights

Highlights of GAO-09-860T, testimony before the Subcommittee on Clean Air and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate

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 laws 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.

This testimony provides preliminary data from GAO's ongoing work on (1) reductions achieved by mercury control technologies and the extent of their use at coal-fired power plants, (2) the cost of mercury control technologies in use at these plants, and (3) key issues EPA faces in regulating mercury emissions from power plants. GAO obtained data from power plants operating sorbent injection systems.

View GAO-09-860T or key components.
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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 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, sorbent injection has not been tested on a small number of boiler configurations, some of which achieve high mercury removal with other pollution control devices.

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 $640,000. 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. For example, 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. Data from EPA's 1999 power plant survey do not reflect commercial deployments or DOE tests of sorbent injection systems and could support a standard well below what has recently been broadly achieved. Moreover, the time frame for proposing the standard may be compressed because of a pending lawsuit. On July 2, 2009, EPA announced that it planned to conduct an information collection request to update existing emission data, among other things, from power plants.

Mr. Chairman and Members of the Subcommittee:

I am pleased to be here today to discuss our preliminary findings on the effectiveness and costs of mercury control technologies, as well as key issues the Environmental Protection Agency (EPA) faces in developing a regulation for mercury emissions from coal-fired power plants. 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]

EPA determined in 2000 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 establishing 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[3]—which will require most existing coal-fired boilers to reduce mercury emissions to at least the average level achieved by the best performing 12 percent of boilers.[4] While developing MACT standards for hazardous air pollutants can take up to 3 years, EPA may be required to promulgate these standards in a shorter period of time to fulfill a negotiated settlement with litigants or comply with a court decision. Specifically, EPA has until July 27, 2009, to settle or respond to a lawsuit filed by several environmental groups requesting an order requiring the EPA Administrator to

[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.

[2]EPA's cap-and-trade program, known as the Clean Air Mercury Rule, was established under Clean Air Act section 111 and was to establish a cap on mercury emissions of 38 tons for 2010 and a second phase cap of 15 tons for 2018.

[3]According to EPA, its MACT will also cover the other hazardous air pollutants listed in the Clean Air Act as well as emissions from oil-fired power plants.

[4]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.

promulgate final mercury emissions standards for coal-fired power plants by a date certain no later than December 2010.

The Department of Energy's (DOE) National Energy Technology Lab has worked with EPA and the Electric Power Research Institute (EPRI), 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 on all coal types and at a variety of boiler configurations at operating power plants.[6] Testing at a variety of boiler configurations using different types of coal 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. Further, some power plants achieve mercury reductions as a "co-benefit" of using controls designed to reduce other pollutants, such as sulfur dioxide, nitrogen oxides, and particulate matter.

According to a 2008 DOE report describing 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 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. In recent years, at least 18 states have passed laws or regulations requiring mercury emission reductions at coal-fired power plants. The compliance time frames for the state requirements vary, and four states—Connecticut, Delaware, Massachusetts, and New Jersey—require reductions currently. 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

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

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.

We are currently responding to these objectives. To do this, we are identifying 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 are obtaining data from plant managers and engineers on the effectiveness of sorbent injection systems at reducing mercury emissions and the costs of doing so. We are also obtaining information on the engineering challenges plant officials have encountered in installing and operating sorbent injection systems and actions taken to mitigate them.[7] In addition, we are examining DOE National Energy Technology Lab, EPRI, and academic reports on the effectiveness and costs of sorbent injection systems over time and reviewing literature from recent technical conferences that addressed strategies to overcome challenges that some plants have experienced with sorbent injection systems. We are also reviewing 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 have met with EPA officials in the Office of Air and Radiation regarding the agency's plans for regulating mercury at power plants. EPA officials in the Offices of Air and Radiation and Research and Development provided comments on the information provided in this testimony, and we have made technical clarification where appropriate.

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

[7]To date, we have visited seven plants using sorbent injection systems, and we have interviewed plant managers at five other plants that are meeting state mercury emissions requirements with existing pollution control devices for other pollutants.

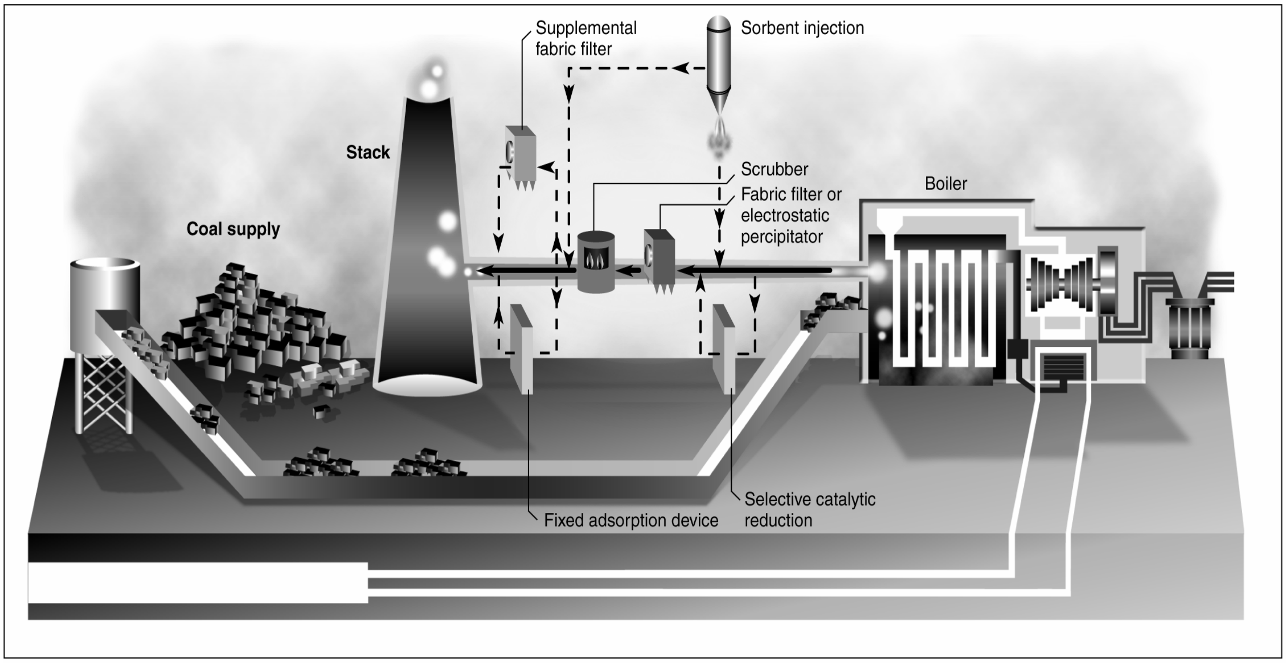
chain as predator species consume the smaller organisms. Fish contaminated with methylmercury may pose health threats to people who rely on fish as part of their diet. Mercury can harm fetuses and cause neurological disorders in children, resulting in, among other things, impaired cognitive abilities. 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. 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. In addition to mercury, coal combustion releases other harmful air pollutants, including sulfur dioxide and nitrogen oxides.[8] EPA has regulated these pollutants since 1995 and 1996, respectively, through its program intended to control acid rain. Figure 1 shows various pollution controls that may be used at coal-fired power plants: selective catalytic reduction to control nitrogen oxides, wet or

[8]Pollution controls that may be used at coal-fired power plants include selective catalytic reduction to control nitrogen oxides, wet or dry scrubbers to reduce sulfur dioxide, electrostatic precipitators and fabric filters to control particulate matter, and sorbent injection to reduce mercury emissions.

dry scrubbers to reduce sulfur dioxide, electrostatic precipitators and fabric filters 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: Electric Power Research Institute.

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. 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 mercury reduction costs—primarily 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 emission reductions.

Under its mercury testing program, DOE initially tested the effectiveness of untreated carbon sorbents. On the basis of these results, 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 coals.[9] DOE went on to test the effectiveness of chemically treated sorbents—which can help convert the more difficult-to-capture mercury common in lignite and subbituminous coals to a more easily captured form—and achieved high mercury reduction across all coal types.[10] Finally, DOE continued to test sorbent injection systems and to assess solutions to impacts on plant devices, structures, or operations that may result from operating these systems—called "balance-of-plant impacts."[11] In 2008, DOE reported that the high performance observed during many of its field tests at a variety of configurations has given coal-fired power plant operators the confidence to begin deploying these technologies.

Bills have been introduced in the prior and current Congress addressing mercury emissions from power plants. The bills have proposed specific limits on mercury emissions, such as not less than 90 percent reductions, and some have specified time frames for EPA to promulgate a MACT regulation limiting mercury emissions from power plants. For example, a bill introduced in this Congress would require EPA to promulgate a MACT standard for mercury from coal-fired power plants within a year of the bill's enactment. In addition, some bills introduced the past few years—termed multipollutant bills—would have regulated sulfur dioxide, nitrogen oxides, and carbon

[9]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).

[10]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.

[11]Near the end of the research program, DOE continued field tests of advanced mercury control technologies but aimed to achieve 90 percent or greater mercury capture at low costs and to have them available for commercial demonstration by 2010. According to a DOE official, federal funding for DOE tests was eliminated before the final phase of tests was completed.

dioxide emissions, in addition to mercury, from coal-fired power plants. Most would have required a 90 percent reduction—or similarly stringent limit—of mercury emissions, with the compliance deadlines varying from 2011 to 2015. One such bill currently before Congress would prohibit existing coal-fired power plants from exceeding an emission limit of 0.6 pounds of mercury per trillion British thermal units (BTUs), a standard measure of the mercury content in coal—equivalent to approximately a 90 percent reduction—by January 2013.

Substantial Mercury Reductions Have Been Achieved Using Sorbent Injection Technology at 14 Plants and in Many DOE Tests, but Some Plants May Require Alternative Strategies to Achieve Comparable Results

The managers of 14 coal-fired power plants reported to us they currently operate sorbent injection systems on 25 boilers to meet the mercury emission reduction requirements of 4 states and several consent decrees and construction permits.[12] Preliminary data 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 have met or surpassed their relevant regulatory mercury requirements, according to plant managers. For example:

- A 164 megawatt bituminous-fired boiler, built in the 1960s and operating a cold-side electrostatic precipitator and wet scrubber, exceeds its 90 percent reduction requirement—achieving more than 95 percent mercury emission reductions using chemically treated carbon sorbent.
- A 400 megawatt subbituminous-fired boiler, built in the 1960s and operating a cold-side electrostatic precipitator and a fabric filter, achieves a 99 percent

[12]To date, we have interviewed managers at plants with 24 of the 25 sorbent injection systems. 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.

[13]This number reflects 9 boilers that were required to achieve 90 percent mercury emission reduction—which seven surpassed—and 10 boilers that were required to achieve reductions between 80 percent and 89 percent. Plant officials did not provide data on mercury reductions achieved by sorbent injection systems for 5 boilers. Data for another boiler are pending.

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 achieves 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, 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 its national mercury regulation.[14] 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.[15] 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 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.[16] Some boiler configurations tested in the DOE program that are not yet included in commercial deployments follow:

[14]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.

[15]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.

[16]We identified 56 field tests conducted by DOE during its mercury control technology testing program. Of these tests, we examined mercury reduction data of 41 tests conducted at power plants. The majority of these tests were long-term tests (30 days or more). We did not include mercury reduction data associated with the other 15 tests in our analysis 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.

- 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.[17]

As these examples of deployed and tested injection systems show, plants are using chemically treated sorbents and sorbent enhancement additives, as well as untreated sorbents. The DOE program initially used untreated sorbents, but during the past 6 years, the focus shifted to chemically treated sorbents and enhancement additives that were being developed. These more recent tests 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 sorbent reduced mercury by an average of 55 percent during a 2003 DOE test at a subbituminous-fired boiler. Recent tests using chemically treated sorbents and enhancement additives, however, have resulted in average mercury reductions of 90 percent for boilers using subbituminous coals.[18] Similarly, recent tests on boilers using lignite reduced mercury emissions by roughly 80 percent, on average.

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

[18]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.

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. Specifically, regulated coal-fired power plants typically use either electrostatic precipitators or fabric filters for particulate matter control. The use of fabric filters—which are more effective at mercury emission reductions than electrostatic precipitators—at coal-fired power plants to reduce emissions of particulate matter and other pollutants is increasing, but currently less than 20 percent have them. Plant officials told us that they chose to install fabric filters along with 10 of the sorbent injection systems currently deployed to assist with mercury control—but that some of the fabric filters were installed primarily to comply with other air pollution control requirements. One plant manager, for example, told us that the fabric filter installed at the plant helps the sorbent injection system achieve higher levels of mercury emission reductions but that the driving force behind the fabric filter installation was to comply 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.[19]

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. Funding for the DOE testing program has been eliminated.[20] Regarding deployments to meet state requirements that will become effective in the near future, the Institute of Clean Air Companies reported that power plants had 121 sorbent injection systems on order as of February 2009.[21]

[19]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.

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

[21]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 beyond. Georgia and North Carolina require installation of other pollution control devices between 2008 and 2018 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.

Importantly, mercury control technologies will not have to be installed on a number of coal-fired boilers to meet mercury emission reduction requirements because they already achieve high mercury reductions from their existing pollution control devices.[22] EPA data indicate that about one-fourth of the industry may be currently achieving mercury reductions of 90 percent or more as a co-benefit of other pollution control devices.[23] 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.[24] One plant manager told us their plant achieves 95 percent mercury reduction 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.

While sorbent injection technology has been shown to be effective with all coal types and on boiler configurations 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. For example:

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[22]Nationwide, mercury reductions achieved as a co-benefit of other pollution control devices reduces 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 capture.

[23]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.

[24]Two of these plants 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.

- Sulfur trioxide—which can form under certain operating conditions or from using high sulfur bituminous coal—may limit mercury reductions because it prevents mercury from 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, has relatively high levels of elemental mercury—the most difficult form to capture. Lignite is found primarily in North Dakota and the Gulf Coast, the latter 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 83 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 I. 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, which EPA is currently developing, and as some plants add air pollution control technologies required under consent decrees. 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, such as selective catalytic reduction devices for nitrogen oxides control and wet scrubbers for sulfur dioxide control, which are often associated with high levels of mercury emission reductions.

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 (see table 1).[25] For these boilers, the cost ranged from $1.2 to $6.2 million.[26] 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—the estimates range from $32.6 to $137.1 million.[27] EPA's estimate of the average cost to purchase and install a selective

[25]All reported cost data have been adjusted for inflation and are reported in 2008 dollars.

[26]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.

[27]EPA cost estimates reported in 2006 have been adjusted for inflation and are reported in 2008 dollars.

catalytic reduction device to control nitrogen oxides is $66.1 million, ranging from $12.7 to $127.1 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, these boilers have uncommon configurations—ones that, as discussed earlier, DOE tests showed would need additional control devices to achieve high mercury reductions.[28] Table 1 shows the per-boiler capital costs of sorbent injections systems depending on whether fabric filters are also installed primarily to reduce mercury emissions.

[28]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.

Table 1: Average Cost to Purchase and Install Mercury Control Technologies and Monitoring Equipment, per Boiler

2008 dollars

Mercury control technology	Number of boilers[a]	Sorbent injection system	Mercury emissions monitoring system	Consulting and engineering	Fabric filter	Total
Sorbent injection system	14	$2,723,277	$559,592	$381,535	[b]	**$3,594,023**[c]
Sorbent injection system and fabric filter to assist in mercury removal	5	$1,334,971	$119,544	$1,444,179	$19,009,986	**$15,785,997**[d]

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

[a] We identified 25 boilers with 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. Costs for the remaining 5 are discussed further below because much of the cost incurred for fabric filters in these cases is not related to mercury removal.

[b] Not applicable.

[c] Numbers do not add to total. Total capital costs data were provided for 14 boilers in this category, and these totals were used to provide the average total capital cost. However, the average cost for the individual cost categories include data on only 12 of the 14 boilers in this category for which we were provided data.

[d] Numbers do not add to total. Total capital cost data were provided for five boilers with fabric filters, and these totals were used to provide the average total capital cost. However, the average cost for the individual cost categories only include data on two of the five boilers for which we were provided data.

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 both the sorbent injection system and fabric filter was $105.9 million per boiler, ranging from $38.2 million to $156.2 million per boiler.[29] 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, sulfur dioxide, and nitrogen oxide reductions, as well as EPA's upcoming MACT regulation for coal-fired power

[29] 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.

plants that, according to EPA officials, will regulate mercury as well as other air toxics emitted from these plants.

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 emission reduction required to meet regulatory requirements and to 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.[30]

Plant engineers often adjust the injection rate of the sorbent to capture more or less mercury—the more sorbent in the exhaust gas, for example, 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, 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. One state's consent decree, for example, requires plants to operate their sorbent injection systems at an injection rate of 5 pounds per million actual cubic feet.[31] Among the 19 boilers for which plant managers provided operating 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.

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[30]Sorbent costs ranged from $76,500 to $2.4 million.

[31]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.

For those plants that installed a sorbent injection system alone—at an average cost of $3.6 million—to meet mercury emissions requirements, 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.[32] Minnesota, for example, passed a law in 2006 allowing power companies to seek regulatory approval for recovering the cost of anticipated state-required reductions in mercury emissions in advance of the regulatory schedule for rate increase requests. One utility in the state submitted a plan for the installation of sorbent injection systems to reduce mercury emissions at two of its plants at a cost of $4.4 and $4.5, respectively, estimating a rate increase of 6 to 10 cents per month for customers of both plants.[33]

For power companies operating in competitive markets where wholesale electricity prices are not regulated, prices are largely determined by supply and demand.[34] Generally

[32]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 utility's request and decide what costs are allowable under the relevant rules.

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

[34]If demand for electricity is elastic (that is, consumers have some flexibility in adjusting the quantities that they purchase in response to price changes), suppliers may not be able to raise prices in order to fully recover the incremental cost of mercury emissions control. For instance, if pollution controls add 5 percent to the cost of generating electricity, the generating company may be able to raise its prices by only 3 percent.

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 beneficial purposes, such 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. Specifically, some plant managers told us that they have incurred additional costs because of lost fly ash sales and additional costs to store fly ash that was previously either sold or donated for beneficial 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.[35]

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

[35]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 as 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.

include refining sorbents through milling and changing the sorbent injection sites. Specifically, in testing, milling of 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[36] can decrease the amount of sorbent needed to achieve desired levels of mercury control.

Some plant managers reported other balance-of-plant impacts associated with sorbent injection systems, such as ductwork corrosion and small fires in the particulate matter control devices. Plant engineers 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 the corrosion problem remains unresolved but that it is primarily a minor engineering challenge not impacting 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 originally expected.

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 mercury emissions limit. 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

[36]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.

these issues could affect the stringency of the MACT standard the agency proposes. In addition, the format of the standard—whether it limits the mercury content of coal being burned (an input standard) or of emissions from the stack (an output standard)—may affect the stringency of the MACT standard the agency proposes. Finally, the vacatur of the Clean Air Mercury Rule has delayed for a number of years the continuous emissions monitoring that would have started in 2009 at most coal-fired power plants. Consequently, data on mercury emissions from coal-fired power plants and the resolution of some technical issues with monitoring systems have both been delayed.

Current Data from Commercial Deployments and DOE Tests Could Be Used 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[37]—is a critical initial step in the development of a MACT standard for mercury. 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,[38] EPA established subcategories for the types of coal most commonly used by power plants.[39] 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 standard(s). 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.

[37]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.

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

[39]Under the Clean Air Act Amendments of 1990, EPA had 10 years from the enactment of the amendments, or two 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 two years, or until 2002, to promulgate a MACT standard.

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. Information collection requests are required when an agency collects data from 10 or more nongovernmental parties. According to EPA officials, this data collection process, which requires Office of Management and Budget (OMB) review and approval, typically takes from 8 months to 1 year. EPA's schedule for issuing a proposed rule and a final rule has not yet been established as the agency is currently in negotiations with litigants about these time frames. In developing the rule, EPA told us it could decide to use data from its 1999 information collection request, data from commercial deployments and DOE tests to augment its 1999 data, or implement a new information collection request for mercury emissions. 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.

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 of the best performers, from which the standard is derived, may be higher. Our analysis of EPA's 1999 data shows an average mercury emission reduction of nearly 91 percent for the best performers.[40] 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 lower than the 1999 average emission reduction of the best performers because of variability in mercury emissions among the top performers, as discussed in more detail below.

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

Second, more current information that reflects mercury control deployments and DOE tests may make the rationale EPA used to create MACT standards for different subcategories less compelling to the agency now. In its 2004 proposed MACT, using 1999 data, EPA proposed separate standards for three subcategories of coal used at power plants, largely because the co-benefit capture of mercury from subbituminous- and lignite-fired boilers was substantially less than from bituminous-fired boilers and resulted in higher average mercury emissions for best performers using these coal types. Specifically, the 1999 data EPA used for its 2004 MACT proposal 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 using sorbent injection systems with all coal types has achieved at least 90 percent mercury emission reductions in most cases.

Finally, using more current emissions data in setting the mercury standard, may mean that accounting for variability in emissions will not have as significant an effect as it did in the 2004 proposed MACT—thereby lowering the MACT standard—because the current data 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 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. 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.[41] Similarly, another manager of a power plant operating a sorbent injection system told us the amount of mercury in the coal they use "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 British thermal units (BTUs) of heat input; output-based standards, on the other hand, establish emission limits on the basis of pounds of mercury per megawatt hour of electricity produced. These standards are referred to as absolute limits. For the purposes of setting a standard, absolute 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

[41]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.

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).

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.[42] 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, which 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.

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 reduction or emission limit—are greater.[43] On the basis of our

[42]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.

[43]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; and Arizona requires the more stringent option.

review of these varying regulatory formats, we conclude that to be meaningful, a standard specifying a percent reduction should be correlated to an absolute limit. When used alone, percent reduction standards can limit mercury emissions reductions. For example, in one state, mercury reductions are measured against "historical" coal-mercury content data, rather than current coal-mercury content data. 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 high 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 limit actual mercury emission reductions. For example, a plant burning coal with a mercury content of 15 pounds per trillion BTUs that may choose between meeting an absolute 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 absolute limit. As discussed above, for the purposes of setting a standard, a required absolute limit, which 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 equates to an emission limit of approximately 0.7 pounds per trillion BTUs.[44] For bituminous coal, a 90 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

[44]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.

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, as Has Resolution of Emissions Monitoring Challenges

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, the monitoring requirements are important to state agencies with mercury reduction requirements. This association for state clean air agencies 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. As a result, continuous monitoring of mercury emissions from coal-fired power plants may continue to be delayed for years.

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 a continuous emissions monitoring systems (CEMS) certification process and approve protocols for quality control and assurance. However, when the Clean Air Mercury Rule was vacated, EPA put its CEMS certification process on hold.

Effective emissions monitoring assists facilities and regulators in ensuring compliance with regulations and can also help facilities identify ways to better understand the efficiency of their processes and the efficiency of their operations. 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, for example, is emitted at lower levels of concentration than other pollutants and is measured in parts per billion—it is like "trying to find a needle in a haystack," according to one plant engineer. Consequently, mercury CEMS require more time to install and setup than CEMS for other pollutants, and, according to plant engineers using them, they involve a steeper learning curve in getting these relatively complex monitoring systems up and running properly.

EPA plans to release interim quality control protocols for mercury CEMS in July 2009. In our work, we found that these systems are installed on 16 boilers at power plants for monitoring operations or for compliance reporting.[45] Our preliminary data shows that for regulated coal-fired boilers, plant managers reported that their mercury CEMS were online from 62 percent to 99 percent of the time. When these systems were offline, it was mainly because of failed system integrity checks or routine parts failure. Some plant engineers told us that CEMS are accurate at measuring mercury, but others said that these systems are "several years away" from commercial readiness. However, according to an EPA Clean Air Markets Division official, while some technical monitoring issues remain, mercury CEMS are sufficiently reliable to determine whether plants are complying with their relevant state mercury emissions regulations.

[45]At least 14 states have enacted mercury emission standards that include a mercury monitoring requirement. Six states require monitoring to be conducted in accordance with the monitoring provisions of the Clean Air Mercury Rule. Four states require sole use of CEMS. Three states allow periodic stack tests—a method not approved under the Clean Air Mercury Rule—until CEMS can be used at a later date. One state requires use of CEMS or other method approved by the state environmental protection agency.

Concluding Observations

Data from commercially deployed sorbent injection systems show that substantial mercury 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 substantial mercury emission 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 emit small amounts of mercury without mercury-specific controls because their existing controls for other air pollutants also effectively reduce mercury emissions. In fact, while many power companies 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 will likely find that current data from commercially deployed sorbent injection systems and plants with high native mercury capture justify a more stringent mercury emission standard than was last proposed in

2004. More significant mercury emission 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.

Mr. Chairman, this concludes my prepared statement. We expect to complete our ongoing work by October 2009. I would be happy to respond to any questions that you or other Members of the Subcommittee may have at this time.

GAO Contact and Staff Acknowledgments

Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this statement. For further information about this testimony, please contact me at (202) 512-3841 or stephensonj@gao.gov. Key contributors to this statement were Christine Fishkin (Assistant Director), Nathan Anderson, Mark Braza, Antoinette Capaccio, Nancy Crothers, Philip Farah, Mick Ray, and Katy Trenholme.

Appendix I: Potential Solutions to Challenges Associated with Achieving Mercury Emissions Reductions of 90 Percent or More Using Sorbent Injection Systems

DOE tests show that some plants may not be able to achieve mercury 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.

<u>Sulfur trioxide interference</u>. 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 vendors are working to develop alternative conditioning agents that could be used instead of sulfur trioxide in the conditioning system to improve the performance of electrostatic precipitators without jeopardizing mercury emission reductions using sorbent injection.
- Selective catalytic reduction systems, a common control device 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 in the future 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 have or to install scrubbers for controlling sulfur dioxide at plants burning high sulfur coal and are more likely to use the scrubbers, rather than sorbent injection systems, to also reduce mercury emissions.

Hot-side electrostatic precipitators. Installed on 6 percent of boilers nationwide, these particulate matter control devices operate at very high temperatures, which reduce the incidence of mercury binding to sorbents for collection in particulate matter control devices. However, at least two promising techniques have been identified in tests and commercial deployments at configuration types with hot-side electrostatic precipitators. First, 70 percent mercury emission reductions were achieved with specialized heat-resistant sorbents during DOE testing. 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.[46] 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 currently use this system to comply with a consent decree and achieved 94 percent

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

mercury emission reductions during the third quarter of 2008, the most recent compliance reporting period when 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 burning North Dakota lignite and having 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, 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 reduction 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 removal of 83 percent using untreated carbon and a boiler additive in conjunction with the existing electrostatic precipitator and wet scrubber.

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