Nos. 14-46, -47, -49

In the Supreme Court of the United States

MICHIGAN, ET AL., PETITIONERS,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

UTILITY AIR REGULATORY GROUP, PETITIONER,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

NATIONAL MINING ASSOCIATION, PETITIONER,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

On Writs of Certiorari To The United States Court of Appeals For The District of Columbia

BRIEF OF *AMICI CURIAE* EXPERTS IN AIR POLLUTION CONTROL AND AIR QUALITY REGULATION IN SUPPORT OF RESPONDENTS

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INTEREST OF THE *AMICI CURIAE*[1]

Amici Curiae are Paul Miller, John Paul, Ranajit Sahu, and Eric Svenson. The *Amici* wish to supply the Court with information regarding the practicability of reducing hazardous air pollutant (HAP) emissions from coal-fired electric utility steam generating units (EGUs) as of 2000, the date of EPA's original finding that regulation was appropriate and necessary. They further explain why in their view, based on the availability of various control technologies for reducing HAP emissions – the costs of which were reasonably well known and had been proven to not be prohibitive – it was reasonable for EPA not to formally consider costs in making this finding. *Amici* also wish to provide the Court with an understanding of the advancements in control technologies from 2000 to 2012 and how these advances support EPA's affirmation of the appropriate and necessary finding

Amicus Dr. Paul Miller is the Deputy Director and Chief Scientist of Northeast States for Coordinated Air Use Management (NESCAUM) where he provides the organization with legal, technical, and policy support for all NESCAUM initiatives. He plays a leading role in supporting

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[1] No counsel for any party had any role in authoring this brief, and no persons other than the *amici curiae* and their counsel made any monetary contribution to its preparation or submission. Written consents from the parties to the filing of this brief are on file with the Clerk.

state efforts to address acid deposition, mercury emissions and other air and climate issues. Dr. Miller has been a Senior Fellow at Princeton University's Center for Energy and Environmental Studies, and a National Research Council Associate at the Joint Institute for Laboratory Astrophysics, University of Colorado, Boulder. He has a Ph.D. in Chemical Physics from Yale University and a J.D. from Stanford University.

Amicus Mr. John Paul recently retired from his position as Administrator of the Regional Air Pollution Control Agency (RAPCA) of Dayton, Ohio. Mr. Paul worked for the agency from 1973 through June of 2014 and served as its director from 1985. He holds a Master of Science from Iowa State University and a Bachelor of Science from Michigan State University. Mr. Paul was active in air pollution control issues in the State of Ohio and nationwide. He served as co-chair of the National Association of Clean Air Agencies' New Source Review Committee, as well as several terms as an officer and member of the Board of Directors. He served two six-year terms on EPA's Clean Air Act Advisory Committee (CAAAC) and co-chaired the CAAAC working group on the utility MACT.

Amicus Dr. Ranajit Sahu is an environmental engineer and consultant based in Southern California. Dr. Sahu has more than 25 years of experience in the fields of environmental, mechanical and chemical engineering, including: design and specification of environmental control equipment, hazardous waste remediation, air pollution control

and equipment design, combustion process engineering, energy studies, multimedia environmental regulatory compliance, transportation air quality impact analysis, multipathway health risk assessments for toxics, air dispersion modeling, regulatory strategy development, and design for pollution prevention. He has provided numerous industrial, government, commercial and public interest group clients with comprehensive multimedia compliance assistance encompassing all media (air, water, solid and hazardous waste, mixed waste, noise and community issues). He has Ph.D. and M.S. degrees in Mechanical Engineering from the California Institute of Technology and a B.Tech degree from the Indian Institute of Technology.

Amicus Mr. Eric Svenson is a Senior Advisor with M.J. Bradley & Associates (MJB&A) where he focuses on strategic planning and analysis for the electric and gas utility industry. He has over 39 years of experience in many aspects of the industry including: electric power plant operations, engineering and construction, strategic planning, and electric and gas transmission and distribution systems. He also has significant expertise in state, regional, and federal public policies pertaining to economic, energy, and environmental regulation. Prior to joining MJB&A, Eric was the Vice President for Environment, Health and Safety for Public Service Enterprise Group, a $16 billion market cap Fortune 500 electric and gas utility headquartered in Newark, NJ. He co-chaired EPA's Greenhouse Gas Best Available Control Technology (BACT) committee that provided advice to EPA for its

development of BACT regulation and co-authored with the Natural Resources Defense Council several reports benchmarking electric power industry emissions. He holds a Master of Engineering – Mechanical degree from Stevens Institute of Technology.

All *Amici* file this brief solely as individuals and not on behalf of the institutions with which they are affiliated.

SUMMARY OF THE ARGUMENT

Fossil fuel-fired power plants account for nearly seventy percent of electricity generation in the United States. Coal-fired power plants alone account for nearly forty percent of total generation. Coal-fired generation results in emissions of numerous air pollutants, some of which are toxic and cause or may cause cancer or other serious health effects. As coal is burned in utility boilers, mercury and other heavy metals are released, as are halogens, which form acid gases such as hydrogen chloride and hydrogen fluoride. These metals and gases are considered HAPs under Section 112 of the Clean Air Act.

Based on studies EPA performed and other information available to it at the time, EPA concluded in 2000 that it was appropriate and necessary to regulate HAP emissions from coal- and oil-fired[2] EGUs. It based this finding in part on the

[2] Coal-fired EGUs emit by far the largest amount of utility-originated HAPs. Oil-fired EGUs contributed to less than two

health hazards posed by HAPs emitted by EGUs, particularly mercury, and on its determination that when it eventually promulgated a regulation, EGUs would be able to control their HAP emissions using technologies that were, for the most part, already available and already in use at many EGUs in 2000. In 2012, after an additional decade of experience with and study of the technological, economic and operational feasibility of HAP controls, EPA affirmed its 2000 finding. Both decisions were reasonable and supported by the facts known to EPA and throughout the industry.

ARGUMENT

In December 2000, after nearly a decade of study of the health effects posed by EGU HAP emissions and the control strategies available to reduce such emissions, EPA determined that the regulation of HAPs emitted by coal-fired EGUs was appropriate and necessary. This decision was based in part on EPA's conclusion that technologies for controlling HAP emissions that posed a threat to the public health would be available for use (and in some cases were already in use) once EPA promulgated its regulation. More than eleven years later, EPA affirmed this decision, finding that the control of EGU HAP emissions was achievable with existing

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percent of the total HAP emissions for 1990 and 2010. Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units, 65 Fed. Reg. 79,828 (Dec. 20, 2000). Therefore, this brief does not discuss oil-fired EGUs and focuses solely on coal-fired EGUs.

technologies and without placing the reliability of electric service at risk.

I. IN 2000, EPA REASONABLY FOUND IT APPROPRIATE TO REGULATE EGU HAP EMISSIONS WITHOUT FORMALLY CONSIDERING COSTS BECAUSE CONTROL TECHNOLOGIES FOR REDUCING SUCH EMISSIONS WERE ALREADY AVAILABLE AND WIDELY USED, AND THE COSTS OF THOSE TECHNOLOGIES WERE NOT PROHIBITIVE.

A. The HAPs Emitted By EGUs Include Mercury, Non-Mercury Metals, Acid Gases, And Organic HAPs; Mercury Has Been Identified As The HAP Of Greatest Potential Concern For Public Health.

EGUs emit a variety of HAPs including mercury, non-mercury metals, acid gases, and organic HAPs.[3]

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[3] Organic HAPs include dioxins and furans. The significant majority of data obtained by EPA for measured organic HAP emissions from EGUs were below the detection levels of the EPA test methods, leading EPA to conclude that it is impracticable to measure organic HAP emissions from EGUs and to propose work practice standards for organic HAPs instead of the emission limitations it set for the other HAPs. 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,

Mercury and non-mercury metals (arsenic, cadmium, chromium, lead, nickel, selenium, and others) are naturally occurring elements found in coal in trace amounts. Non-mercury metals generally do not volatilize (convert into a gaseous state) when coal is burned in utility boilers and instead remain as solid particles or bound to solid particles in the residual ash. Mercury, by contrast, is highly volatile and tends to vaporize and become entrained in the flue gas (combustion exhaust) as either elemental or ionic mercury vapor. Coal characteristics, *e.g.*, rank,[4] and combustion conditions dictate which form of vapor phase mercury predominates. A small amount of mercury, typically less than 10 percent, does not volatilize when coal is burned in utility boilers and remains in the residual ash as particle-bound mercury.

Coal also contains halogens, highly reactive elements in a group that includes fluorine, chlorine, bromine, and iodine. When coal is burned in utility boilers the halogens are released and form strong acids – primarily hydrogen chloride (HCl) and

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77 Fed. Reg. 9,369 (Feb. 16, 2012). Therefore, organic HAPs will not be further discussed in this brief.

[4] Rank is a measure of the degree of alteration that occurs as buried organic matter undergoing coalification is subjected to increasing temperature and pressure. Lower rank coals contain less carbon and have a lower energy content than higher rank coals. Lower rank coals also generally contain less chlorine, which oxidizes mercury making it easier to capture in air pollution control devices. The major ranks, from lowest to highest, are lignite, subbituminous coal, bituminous coal, and anthracite.

hydrogen fluoride (HF) – as the flue gas cools. The concentration of halogens in coal varies by coal type, although chlorine is usually the most abundant. Coal-fired EGUs emit far more HCl than any other HAP. EPA, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress*, Vol. I 3-15 tbl.3-3 (Feb. 1998) (Utility RTC).

Based on the results of the Utility RTC and on information obtained subsequent to that study, EPA's 2000 finding that regulation of EGU HAP emissions was appropriate identified mercury from coal-fired EGUs as the HAP of greatest concern for public health. Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units, 65 Fed. Reg. 79,825, 79,826 (Dec. 20, 2000) (2000 Finding). Pursuant to §112(n)(1) of the Clean Air Act, EPA performed a study in the late 1990s of the hazards to public health reasonably anticipated to occur as a result of EGU HAP emissions after imposition of the other requirements of the Clean Air Act. EPA examined HAP emissions test data from 52 coal-, oil-, and natural gas-fired utility units for the study and identified 67 of the more than 180 HAPs listed in Section 112 of the Act as potentially emitted by EGUs. Utility RTC at ES-2 to ES-4. EPA then performed an assessment of inhalation and/or multipathway exposure risks for a subset of priority HAPs and concluded that mercury from coal-fired EGUs is the HAP of greatest potential concern for public health due to its high toxicity, its persistence in the environment, and its tendency to

bioaccumulate in food chains. *Id.* at 7-45. EPA also concluded that arsenic and a few other metals are of potential concern for carcinogenic effects, and that dioxins and acid gas HAPs are of potential concern as well. 2000 Finding at 79,827.

B. Technologies Were Readily Available For Controlling Mercury And Other HAPs Emitted By EGUs In 2000.

In 2000, when EPA made its finding that regulation of EGU HAP emissions was appropriate, EPA specifically identified a number of strategies for controlling HAP emissions, including the use of pre-combustion controls (fuel switching, coal switching, coal cleaning, coal gasification), combustion controls (boiler type, low NO_x burners), post-combustion controls (flue gas cleaning technologies), and alternative controls (demand side management, energy conservation). Utility RTC at 13-1 to 13-32. EPA determined that the qualitative effects of these strategies on EGU HAP emissions varied and could not be predicted in some cases. *Id.* at 13-33. However, the ability of readily available post-combustion controls to effectively capture most HAPs emitted by EGUs was well understood. The available technologies for controlling particulate matter had the important co-benefit of capturing metallic HAPs and particle-bound mercury, while the available technologies for controlling sulfur dioxide had the important co-benefit of capturing acid gases and the ionic form of mercury. In addition, recent data indicated that post-combustion control of elemental

mercury, perhaps the most difficult HAP to capture, was also possible.

1. Controls For Non-Mercury Metallic HAPs And Particle-Bound Mercury

Conventional controls for particulate matter (PM) are highly effective for controlling non-mercury metallic HAPs. These HAPs normally form or attach to ash particles and are captured by standard PM control devices, including electrostatic precipitators (ESPs) and fabric filters. Mercury bound to ash particles or other PM is also captured by these devices.

ESPs use an electrical charge to remove particles from flue gas under the influence of an electric field. An ESP imparts a positive or negative charge to incoming particles, then collects the particles on oppositely charged plates or tubes. The collection surfaces are rapped or vibrated periodically to remove the accumulated particles, which are collected in a hopper for disposal. ESP effectiveness depends on the electrical resistivity of the particles and on particle size. High resistivity particles (produced by low-sulfur coal) are more difficult to capture, as are smaller particles. Despite these difficulties, ESPs can capture more than 99 percent of total PM and 80 to 95 percent of $PM_{2.5}$.[5] NORTHEAST STATES FOR COORDINATED AIR USE

[5] $PM_{2.5}$, also known as fine particulate matter, consists of particles 2.5 micrometers in diameter or smaller.

MANAGEMENT, CONTROL TECHNOLOGIES TO REDUCE CONVENTIONAL AND HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS 23 (Mar. 31, 2011) (2011 NESCAUM Report).

Fabric filters trap and collect particles in flue gas as it passes through the filter. The filters are made of woven or felted material in the form of sheets, cartridges, or bags, although bags are the most common type. Gas passes freely through fabric filters, but particles are retained and gradually build up a cake on the fabric which is periodically removed by one of a number of different cleaning mechanisms and collected in a hopper for disposal. Fabric filters are more efficient than ESPs and can capture up to 99.9 percent of total PM and 99 to 99.8 percent of $PM_{2.5}$. *Id.* at 24.

ESPs and fabric filters generally capture greater than 90 percent of all non-mercury metallic HAPs. 2000 Finding at 79,829. Capture rates for particle-bound mercury are comparable to total PM capture rates.

2. Controls For Acid Gas HAPs And Ionized Mercury

Acid gas HAPs (HCl and HF) are effectively captured by conventional controls for sulfur dioxide (SO_2), a highly reactive gas and criteria pollutant emitted in large amounts by coal-fired EGUs. Technologies for capturing SO_2 are called Flue Gas

Desulfurization (FGD) systems and include wet and dry scrubbers and dry sorbent injection.[6]

Wet scrubbers inject an aqueous lime or limestone slurry into the flue gas within a spray tower. SO_2 and acid gases in the flue gas, including HCl and HF, are absorbed by and react with the alkaline slurry to produce a wet solid residue, commonly called FGD sludge, which is then collected for disposal or use as a by-product. Lime is more reactive than limestone and offers the potential for higher removal rates but is also more expensive, so limestone is the most commonly used reagent. Wet scrubbers typically capture over 95 percent of SO_2 and are sometimes capable of removal rates in excess of 98 percent. Removal rates for HCl are even higher. 2011 NESCAUM Report at 10. *See also* AMERICAN LUNG ASSOCIATION, EMISSIONS OF HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS 32 (Mar. 7, 2011).

Dry scrubbers are similar to wet scrubbers in that they inject an aqueous lime slurry into the flue gas to react with acid gases. However, in dry scrubber systems the slurry has a higher sorbent concentration, and the water is evaporated by the heat of the flue gas. As a result, a dry waste product is formed instead of a wet sludge, which is then captured in a standard PM control device. Dry scrubbers are slightly less efficient than wet

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[6] A sorbent is a material that collects molecules of another substance by absorption (drawing molecules into its interstices) or by adsorption (attracting molecules to its surface).

scrubbers but still typically capture more than 90 percent of SO_2. 2011 NESCAUM Report at 11. When used in conjunction with fabric filters, dry scrubbers typically capture about 95 percent of HCl. DAVID G. SLOAT & PAUL S. FARBER, PARTICULATE CONTROL FOR INDUSTRIAL APPLICATIONS 7 (Mar. 25, 2007).

Dry sorbent injection (DSI) is the pneumatic injection of a powdered sorbent directly into the boiler or the downstream ductwork to react with acid gases in the flue gas. The dry reaction products are then captured in a standard PM control device. Capture efficiency depends on the sorbent and the type of PM control device used. The mineral trona, the most common sorbent in use, can capture 30-60 percent of SO_2 when injected upstream of an ESP and up to 90 percent when injected upstream of a fabric filter. 2011 NESCAUM Report at 13. EGUs using DSI with a downstream ESP for particle collection have demonstrated HCl captures rates in the 95-98 percent range. AMERICAN LUNG ASSOCIATION, EMISSIONS OF HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS 33 (Mar. 7, 2011).

Technologies for SO_2 and acid gas HAP control also capture ionic mercury. Ionic mercury vapor is water-soluble and dissolves in and reacts with the aqueous slurry used in wet and dry scrubbers. In wet scrubbers it is collected in the FGD sludge; in dry scrubbers it is captured in the downstream PM control device. Removal rates are highly variable and depend on a number of factors. Wet FGD systems have exhibited capture rates in the 23 to 97 percent

range, while dry FGD systems have exhibited rates in the 3 to 98 percent range. EPA, EPA-600/R-03-110, PERFORMANCE AND COST OF MERCURY AND MULTIPOLLUTANT EMISSION CONTROL TECHNOLOGY APPLICATIONS ON ELECTRIC UTILITY BOILERS 17-18 (Oct. 2003).

3. Controls For Elemental Mercury

Elemental mercury is insoluble in water and has poor reactivity with other species so it is not prone to adsorption onto ash. Approaches for controlling it include converting it into particle-bound mercury by means of adsorption onto activated carbon, or converting it into ionic mercury by adding an oxidizing agent (e.g., chlorine or bromine) or through the use of selective catalytic reduction (SCR) technology.[7]

Conversion of elemental mercury into particle-bound mercury is achieved using activated carbon injection (ACI), which is the pneumatic injection of powdered activated carbon directly into the flue gas. Unlike ash, activated carbon particles effectively adsorb elemental mercury due to their increased surface area, converting it into particle-bound mercury and allowing it to be captured in a standard PM control device. Conversion of elemental mercury into ionic mercury is achieved by adding a halogen to

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[7] SCR technology is used to control nitrogen oxides (NO_x). Flue gas is passed through a catalyst where NO_x reacts with the catalyst and anhydrous ammonia, converting it to nitrogen and water.

the coal or, if ACI is used, to the activated carbon prior to injection. Halogens help oxidize[8] elemental mercury, turning it into ionic mercury which is captured in FGD systems. SCR technology also oxidizes elemental mercury for capture in FGD systems.

EPA was aware of the potential to capture elemental mercury through the use of sorbents such as activated carbon at the time of its 2000 finding. 2000 Finding at 79,829. ACI has since been proven capable of capturing about 65 percent of elemental mercury using untreated carbon, and in the 90 percent range using carbon treated with chemical additives. LARRY GRAY, REVIEW OF CONTROL TECHNOLOGIES FOR MERCURY EMISSIONS FROM COAL-FIRED POWER PLANTS 8-9 (Oct. 24, 2013).

C. Technologies For Controlling Mercury And Other HAPs Emitted By EGUs Were Already Widely Used In 2000.

Technologies for controlling two of the three forms of mercury and other HAPs emitted by EGUs were not only available in 2000, when EPA made its finding that regulation of EGU HAP emissions was appropriate, they were already widely used. Several of these technologies had already been in use for decades by that time.

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[8] "Oxidize" in this situation refers to the removal of electrons to make a positively charged mercury ion.

1. Installed Base Of Non-Mercury Metallic HAP And Particle-Bound Mercury Controls

EPA has regulated some forms of particulate matter since at least 1971, when the first National Ambient Air Quality Standards (NAAQS) were promulgated. EPA, EPA Sets National Air Quality Standards (Apr. 30, 1971), *available at* http://www2.epa.gov/aboutepa/epa-sets-national-air-quality-standards. The original PM NAAQS set limits for total PM. These were replaced in 1987 with limits for PM_{10}[9], and separate limits for $PM_{2.5}$ were added in 1997. EPA, *Particulate Matter (PM) Standards – Table of Historical PM NAAQS*, http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_history.html (last visited Feb. 28, 2015).

For purposes of compliance with the NAAQS and other Clean Air Act requirements, nearly every EGU in the U.S. had already installed PM control devices by 2000, when EPA made its finding. At that time, 300 out of 302 total gigawatts (GW) of coal-fired capacity (99.2 percent) already had PM controls, primarily ESPs (256 GW; 84.9 percent) and/or fabric filters (51 GW; 16.9 percent). EPA, *National Electric Energy Data System (NEEDS) Database v.3.02*, http://www.epa.gov/airmarkets/documents/ipm/NEEDSV3.02_EISA.xls (last visited Mar. 2, 2015) (NEEDS v.3.02). Because these control devices have

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[9] PM_{10} consists of particles 10 micrometers in diameter or smaller.

the co-benefit of capturing metallic HAPs and particle-bound mercury, the installed base of metallic HAP/particle-bound mercury controls was also over 99 percent in 2000.

2. Installed Base Of Acid Gas HAP And Ionized Mercury Controls

Just as the PM NAAQS set limits for that pollutant, the SO_2 NAAQS have set limits for SO_2 since 1971. These limits did not change between 1971 and 2000, except for the revocation of annual and 3-hour secondary standards in 1973 and 1996, respectively.[10] EPA, *Sulfur Dioxide (SO_2) Primary Standards – Table of Historical SO_2 NAAQS*, http://www.epa.gov/ttn/naaqs/standards/so2/s_so2_history.html (last visited Feb. 28, 2015). Additionally, in 1990 Congress recognized that SO_2 pollution was causing a serious problem that was not being addressed through the NAAQS – acid deposition, also known as acid rain.[11] The 1990 Clean Air Act amendments directed EPA to establish a program to control acid rain. EPA did so, implementing the Acid

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[10] Primary NAAQS provide public health protection. Secondary NAAQS provide public welfare protection, e.g., protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

[11] The presence of acid gases in the air can cause atmospheric water vapor to shift from a neutral pH to an acidic pH. When the acidic water vapor condenses, it becomes acid rain, or acid snow, and can damage trees and other vegetation as well as cars and buildings. In some cases, the acid gases remain in gas form or cause dust particles to become acidic. In this form, they can be inhaled and cause health problems.

Rain Program in 1995 which regulated SO_2 emissions from EGUs through a cap-and-trade program. For purposes of compliance with the NAAQS and other Clean Air Act requirements and programs, including the Acid Rain Program, some EGUs – primarily in the Northeast and the Midwest – had already installed scrubbers by 2000, when EPA made its finding. EPA, EPA430-R-99-011, PROGRESS REPORT ON THE EPA ACID RAIN PROGRAM (Nov. 1999). At that time, 73 out of 302 total GW of coal-fired capacity (24 percent) had already installed wet or dry scrubbers. NEEDS v.3.02. Because these control devices have the co-benefit of capturing acid gas HAPs and ionized mercury, the installed base of acid gas HAP/ionized mercury controls was also 24 percent in 2000.

3. Installed Base Of Elemental Mercury Controls

Elemental mercury is the only HAP not captured by controls for other pollutants. However, elemental mercury can be captured using ACI, which converts it to particle-bound mercury for capture in PM control devices, or by adding halogens to the coal (or to the activated carbon, if ACI is used) to convert it to ionized mercury for capture in FGD systems. Neither of these technologies was commercially available when EPA made its regulatory finding in 2000, but their theory of operation was well understood, they had already undergone pilot-scale testing, and full-scale testing on several coal-fired utility boilers was approximately one year away. U.S. DEPARTMENT OF ENERGY, DOE/NETL'S PHASE II MERCURY CONTROL

TECHNOLOGY FIELD TESTING PROGRAM: UPDATED ECONOMIC ANALYSIS OF ACTIVATED CARBON INJECTION 14 tbl.5 (May 2007) (showing initial testing at Alabama Power's E.C. Gaston Unit 3 in April 2001).

D. Because Control Technologies For Reducing Mercury And Other HAPs Emitted By EGUs Were Available And Widely Used, And The Costs Of Those Technologies Were Not Prohibitive, EPA's 2000 Finding Was Reasonable.

By the end of 2000, it was apparent that almost all HAPs, including two of the three species of mercury, could be removed from EGU emissions through the use of control devices that also removed already-regulated criteria pollutants like PM and SO_2 as described above. ESPs and fabric filters, which capture PM, also capture particle-bound mercury and other metallic HAPs that remain as particles or bound to solid particles in the residual ash after coal combustion. *See supra* Part I.B. Additionally, scrubbers and DSI, which capture SO_2, also capture acid gas HAPs and ionized mercury from flue gas. *See supra* Part I.B.

EPA was not blind to the practical implications of controlling EGU HAP emissions when it made its 2000 finding that regulation was appropriate. In fact EPA made its finding based in part on the technological feasibility of controlling HAP emissions, coupled with an understanding of the general expense of mercury and other HAP controls.

2000 Finding at 79,828-30 (noting feasibility of control and technologies that could "greatly reduc[e]" mercury control costs). The general cost of installation and operation of these control devices was well known throughout the electric power generation industry and to EPA. However, the ultimate cost of emission controls depended heavily on the degree of removal efficiency that would eventually be required by regulation after the completion of the administrative rulemaking process.[12] At the finding stage, EPA's analysis demonstrated an understanding of the expense of control devices relative to the overall costs of EGU operation, as an inherent aspect of technological feasibility.

1. ESPs And Fabric Filters

ESPs were the most well-established technology. At the time of EPA's finding, they had been used on boilers for about 80 years. Utility RTC at 2-12. Similarly, as of 2000, fabric filters had been used on utility boilers for about two decades, although not on as wide a scale as ESPs. *Id.* at 2-13. Of course, not all installations were the same and they did not involve the same capital investment or operation costs, but nonetheless, roughly 99 percent of coal-fired EGU capacity had installed ESPs, fabric filters or other PM controls by the end of 1999. NEEDS v.3.02. These control technologies were in place at a near-universal

[12] In fact, Section 112(d)(2) of the Clean Air Act requires this kind of inquiry at the standard-setting stage for all source categories, not just EGUs.

level and were therefore providing a significant amount of metallic HAP and particle-bound mercury control prior to MATS at little additional cost to operators.[13] EPA, *Mercury Study Report to Congress*, ES-14; Vol. VIII 5-20 (Dec. 1997) (Mercury RTC).

2. Flue Gas Desulfurization (Wet/Dry Scrubbers)

By 2000, extensive research had been conducted by EPA and others into the capital and operational costs of various scrubber configurations that could be used to remove acid gases and ionized mercury. *See, e.g.*, EPA, EPA/600/R-00/093, CONTROLLING SO_2 EMISSIONS: A REVIEW OF TECHNOLOGIES 43-84 (Nov. 2000); *Id.* at 84 tbl.6-12 (summarizing costs for various configurations). Industry publications aimed at EGU operators focused on reducing the costs of scrubber operation by examining the factors that could lower the costs of operation, such as age of equipment, use of different coal types and equipment selection. EPRI, FGD OPTIMIZATION WORKBOOK, app. B at 16 tbl.B-8 (Aug. 22, 1998), *available at* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=TR-111118. EPA also offered a tool for estimating capital and operating costs. *See* EPA, EPA/600/R-99/056, COAL UTILITY ENVIRONMENTAL COST (CUECOST) WORKBOOK USER'S MANUAL (1999). Indeed, the basic facts about the conditions most favorable for scrubber use were well known

[13] Some older ESPs might require upgrades or add-on equipment to enhance efficiency.

throughout the power-generation sector. For example, it was known that wet scrubbers had a higher efficiency, and that scrubbers generally were more cost effective on higher capacity generating units. EPA, EPA/600/R-00/093, CONTROLLING SO_2 EMISSIONS: A REVIEW OF TECHNOLOGIES 24, 56 (Nov. 2000). It was also well known that acid gas HAP and mercury removal through the use of SO_2 control technology was a co-benefit and, to the extent that such equipment was already installed, provided acid gas HAP and ionized mercury control at little additional cost to operators. Mercury RTC, Vol. VII, 5-20.

Moreover, it was well known that the marginal cost of SO_2 abatement, including the cost of scrubbers, had dropped significantly between 1990 and 2000, due in part to advances in control technology. Curtis Carlson, *et. al.*, *Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade?,* Resources for the Future Discussion Paper 98-44-REV 34 (Apr. 2000) (the marginal abatement cost of FGD due to technology improvements had dropped by $50 per ton of SO_2). Studies also indicated that industry had significantly overestimated the cost of SO_2 removal during the 1980s and early 1990s. NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT, ENVIRONMENTAL REGULATION AND TECHNOLOGY INNOVATION: CONTROLLING MERCURY EMISSIONS FROM COAL-FIRED BOILERS V-6 to V-7

(Sep. 2000) (2000 NESCAUM Report).[14] At any rate, between 1991 and 1995, 19 GW of U.S. generating capacity installed scrubbers, bringing the installed base to about 24 percent of total generating capacity by 1999.[15] *See supra* Part I.C.2.

3. ACI And Other Sorbent Injection Systems

Although activated carbon injection and other controls for elemental mercury were not yet commercially available in 2000, their theory of operation was well understood, bench- and pilot-scale projects had been completed, and full-scale demonstration projects were in the initial stages, such as the one at FirstEnergy's Eastlake facility near Cleveland, Ohio, with more scheduled to follow, such as the ones at Alabama Power Company's Gaston facility and at the Pleasant Prairie plant in Wisconsin. *FirstEnergy to Demonstrate Multi-Pollutant Control System,* INDUSTRIAL ENVIRONMENT (July 1, 2000), *available at* 2000 WL 9960640 (demonstration of ECO technology to control "nitrogen oxide (NO_x), sulfur dioxide, fine particulate matter, mercury and other substances"); *B&W, Southern Co. announce DOE-Based Projects to*

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[14] *See also* 2000 NESCAUM Report at xiv ("early estimates consistently overstate actual compliance costs, often by a factor of two or more").

[15] This was lower than expected due to the significant drop in the cost of low-sulfur coal. Burning low-sulfur coal proved a cheaper alternative than installing FGD technology. *See* 2000 NESCAUM Report at IV-25 to IV-26.

Reduce Mercury, INSIDE ENERGY (Dec. 25, 2000), *available at* 2000 WL 2108218; EPA, CONTROL OF MERCURY EMISSIONS FROM COAL-FIRED ELECTRIC UTILITY BOILERS 4-6 (Feb. 26, 2004).

Using the results of pilot and bench-scale studies and cost-projection modeling, experts were able to estimate the cost to EGUs of elemental mercury removal. According to EPA, the capital costs of activated carbon technology were relatively low. EPA, EPA-600/R-00/083, PERFORMANCE AND COST OF MERCURY EMISSION CONTROL TECHNOLOGY APPLICATIONS ON ELECTRIC UTILITY BOILERS 7 (Sep. 2000). The then-best estimate of mercury removal costs ranged from 0.305 mills per kilowatt-hour at the low end to 3.783 mills per kilowatt-hour at the highest,[16] just 0.4 to 4.9 percent of the average retail price of electricity in 2000.[17] The costs of elemental mercury removal were roughly comparable to the cost of removing nitrogen oxides. *Id.* at 23.[18]

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[16] The use of hot-side ESP technology at a small number of power plants is responsible for the highest numbers. If those are excluded, the upper end of the range is only 1.915 mills per kilowatt-hour. *Id.* at 22-23.

[17] On average, consumers paid six to eight cents per kilowatt-hour for electricity. U.S. ENERGY INFO. ADMIN., DOE/EIA-0384(2011), ANNUAL ENERGY REVIEW 2011 (Sep. 2012), *available at* http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf. A mill is $\frac{1}{1000}$ of a dollar.

[18] See also 2000 NESCAUM Report at VI-19. Both the EPA study and the NESCAUM report were part of the administrative record EPA assembled in conjunction with the 2000 Finding in preparation for the rulemaking. Docket Nos. I-

Research indicated that the total costs of mercury removal vary according to an EGU's existing configuration of pollution controls, the type of coal it burns, and the efficiency of the mercury removal required. For example, one study showed that a relatively small EGU producing 100 megawatts of power, burning low-sulfur bituminous coal, and equipped with an ESP for controlling PM and ACI and spray cooling for controlling elemental mercury, would experience costs ranging from a low of 1.262 mills per kilowatt-hour if only 60 percent of the total mercury is removed to a high of 2.810 mills per kilowatt-hour if 90 percent of the total mercury is removed, just 1.6 to 3.7 percent of the average retail price of electricity in 2000. *Id.* at 11 tbl.3 (showing ESP-4). To give another example, in September 2000, EPA looked at the effectiveness of removing mercury, evaluating two possible regulatory scenarios and a variety of scrubber/fabric filter/ESP/sorbent injection configurations. Unsurprisingly, the regulatory scenario that required larger reductions of mercury (an 80 percent reduction) cost more than the version that required lower reductions (60 percent). Memorandum, Mercury Cost Calculations: Assumptions, Approach, and Results (Sep. 2000), *available at* http://www.epa.gov/ttn/atw/combust/utiltox/hgmemo.pdf.

In other words, while EPA did not conduct a formal cost-benefit analysis in connection with its

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A-138-40; I-A-143, A-92-55, *available at* http://www.epa.gov/ttn/atw/combust/utiltox/eu_index-master_121603.pdf.

2000 finding that regulation of EGU HAP emissions was appropriate, it was neither blind nor indifferent to the practical aspects of compliance with any rule that it might later promulgate. It was aware of the control technologies and strategies available, it was aware of the factors driving costs of installation and use of those technologies, and it was aware of technological advances on the horizon that could be adopted by EGUs in the near future. Regulation was appropriate because it was practicable and achievable by the industry without compromising grid reliability or economic security.

II. EPA REASONABLY AFFIRMED ITS 2000 FINDING THAT REGULATION WAS APPROPRIATE BECAUSE COST-EFFECTIVE EMISSION CONTROL TECHNOLOGIES FOR MERCURY AND OTHER HAPS WERE IN WIDE USE BY 2012.

By 2012 many EGUs were subject to mercury and other HAP emission requirements through state regulations. In the more than 11 years following EPA's finding that regulation was appropriate, EGUs installed emission control technologies in order to meet state mercury and HAP limits; limits that were in some cases more stringent than those eventually promulgated by EPA. In addition, other federal regulations – such as the EPA rules directed at interstate air pollution, ozone, and acid rain[19] –

[19] The Clean Air Interstate Rule (CAIR) was issued by EPA in 2005. Although it was later invalidated by the D.C. Circuit Court of Appeals in 2008, it remained in effect during litigation

compelled a number of EGUs to install control technologies for other pollutants that have the co-benefit of controlling mercury and other HAPs. In all cases, the EGUs were able to meet regulatory requirements at reasonable cost and without causing a disruption in electrical service. In fact, three years before MATS took effect, the EGUs responsible for a majority of the total electricity generated by coal-fired power plants already had the equipment installed that would enable them to comply with the MATS requirements. EPA explicitly relied on this background in its 2012 affirmation of the 2000 Finding, noting that "cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions." 77 Fed. Reg. 9,418. Because these technologies were available, and because control of HAPs was achievable, it was reasonable for EPA to conclude as it did in 2012 that its 2000 finding that regulation of HAP emissions from EGUs remained appropriate.

A. Between 2000 And 2012, Many EGUs Installed Mercury Emission Control Equipment In Response To State Regulations.

EPA was not the only governmental agency to consider regulation of mercury and other HAPs in

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over the Cross-State Air Pollution Rule (CSAPR). CSAPR is now scheduled to replace CAIR in 2015. 79 Fed. Reg. 71,663. The NO_x SIP Call was issued in 1998 and was designed to control interstate ozone pollution by reducing NO_x emissions.

the late 1990s-early 2000s. A number of state air pollution agencies had been aware of the risks posed by mercury to human health and the environment and were looking at implementing state-wide rules. When EPA made its finding that federal regulation was appropriate and necessary, some states continued to move forward with their own laws.

The earliest state mercury regulation was adopted by New Hampshire in 2002, followed by Connecticut in 2003 and New Jersey in 2004. CLEAN ENERGY GROUP, ENSURING A CLEAN, MODERN ELECTRIC GENERATING FLEET WHILE MAINTAINING ELECTRIC SYSTEM RELIABILITY: SUMMER 2011 UPDATE, app. A (June 2011). These regulations were based in part on a policy decision that requiring mercury control technology was both necessary to protect the public health and was feasible to implement without risking the reliability of the state's electricity grid. *See* JAMES E. MCCARTHY, CONG. RESEARCH SERV., RL33535, MERCURY EMISSIONS FROM ELECTRIC POWER PLANTS: STATES ARE SETTING STRICTER LIMITS 6 & nn. 9-10 (2006).

New Jersey officials observed, for example, that municipal solid waste incinerators using fabric filter control and ACI had achieved 99 percent mercury control over the last decade. They further stated: "The USDOE cost analyses indicate that retrofitting the coal-fired boilers with activated carbon injection (ACI) and [fabric filters] … can achieve 90 percent mercury emission reduction. ACI has a low capitol (sic) cost. It also has low operating costs if [fabric filter] technology is used." *Id.* at n.10 (*quoting* New

Jersey Department of Environmental Protection, Summary of Public Comments and Agency Responses, Control and Prohibition of Mercury Emissions, December 6, 2004 New Jersey Register, pp. 83-84, *available at* http://www.nj.gov/dep/rules/adoptions/mercury_rule7-27.pdf).

In 2005, EPA backtracked from its 2000 finding that regulation of HAP emissions at EGUs was appropriate and necessary and attempted to remove EGUs from the list of regulated sources in Section 112(c) of the Clean Air Act.[20] This decision sparked another round of interest in regulation at the state level, with ten additional states adopting mercury regulations in 2006 and 2007.[21] After that, another five states adopted regulations, bringing the total to eighteen states by the summer of 2011.[22] These eighteen states represent 40 percent of states with

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[20] Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 15,994 (Mar. 29, 2005). EPA then attempted to regulate mercury through section 111 instead. Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, Final Rule, 70 Fed. Reg. 28,606 (May 18, 2005). Both regulations were eventually vacated by the D.C. Circuit.

[21] Those states were Delaware, Maryland, Illinois, North Carolina, Montana, Minnesota, Massachusetts, New York, Colorado, and Georgia. Clean Energy Group, supra, at App. A.

[22] Wisconsin, South Carolina, Michigan, Oregon, and Virginia. *Id.*

coal-fired EGUs.[23] Collectively, they have established mercury limits on approximately 96 GW of coal-fired capacity – approximately 30 percent of total capacity.[24]

In the regulated states, EGUs have been able to achieve mercury emission reductions of 90 percent on average, using the older technologies for controlling PM and SO_2 that also reduce particle-bound and ionized mercury, as well as making use of the newer technologies for controlling elemental mercury that became commercially available after 2000. U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-10-47, MERCURY CONTROL TECHNOLOGIES AT COAL-FIRED POWER PLANTS HAVE ACHIEVED SUBSTANTIAL EMISSIONS REDUCTION 7 (2009). In particular, ACI, which was in the pilot-test stage at the end of 2000, matured as a technology in the first decade of the century. Field testing from 2001-2002 demonstrated that ACI used in conjunction with an ESP was capable of capturing up to 94 percent of the elemental mercury released during the combustion of bituminous coals and approximately 65 percent of the mercury released during the combustion of subbituminous coals. When used in conjunction with a fabric filter, removal efficiencies in excess of 90 percent were achieved while using less sorbent than required to achieve

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[23] Alaska, Hawaii, Idaho, Rhode Island, and Vermont do not have any coal-fired EGUs. EPA, *National Electric Energy Data System (NEEDS) Database v.4.10,* http://www.epa.gov/airmarkets/documents/ipm/NEEDSv410.zip (last visited Mar. 2, 2015) (NEEDS v.4.10).

[24] *Id.*

similar efficiencies with an ESP. NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT, MERCURY EMISSIONS FROM COAL-FIRED POWER PLANTS 4-5 fig.4.2 (2003).

In 2002, Salem Harbor Station in Salem, Massachusetts became the first coal-fired power plant in the U.S. to utilize ACI, installing it on three units. NEEDS v.4.10. By 2010, an additional 65 units had installed or planned to install ACI to meet current or anticipated mercury emission limits.

At the same time, the cost of ACI fell considerably relative to earlier estimates. Before 2000, the estimated costs had relatively large uncertainties and varied considerably, ranging from $10 million to $31 million for a large EGU unit.[25] Mercury RTC, Vol. VIII 3-11 tbl.3-5 (Dec. 1997). By 2007, the costs ranged from $800,000 to $10.3 million while achieving very high removal efficiencies.[26] U.S. DEPARTMENT OF ENERGY, DOE/NETL'S PHASE II MERCURY CONTROL TECHNOLOGY FIELD TESTING PROGRAM: UPDATED ECONOMIC ANALYSIS OF ACTIVATED CARBON INJECTION 32 tbl.11, 35 tbl.14, 38 tbl.17 (May 2007). Such reductions in costs and/or improvements in efficiency are usually expected as a new technology takes hold.

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[25] A large unit has a capacity of 975MW, and a smaller unit 100MW.

[26] These figures represent annualized costs based on tests done over a shorter period.

With controls for elemental mercury added to the existing arsenal of controls, EGUs of differing design, location, and size, that utilize different coals, found it possible to achieve state-established mercury limits.[27] In fact, by the time EPA proposed MATS in 2011, the EGUs in six states were already in compliance with mercury limits stricter than the proposed MATS standard. CLEAN ENERGY GROUP, ENSURING A CLEAN, MODERN ELECTRIC GENERATING FLEET WHILE MAINTAINING ELECTRIC SYSTEM RELIABILITY: SUMMER 2011 UPDATE at 3 (June 2011). The experience of the states that have implemented mercury rules demonstrates that control of mercury emissions is possible with available technology and can be accomplished on a cost-effective basis and without compromising reliability. *See*, *e.g.,* NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT, COMMENTS ON Docket ID No. EPA–HQ–OAR–2009–0234 at 5-8 (AUG. 2, 2011) (discussing experience of NESCAUM states); NATIONAL ASSOCIATION OF CLEAN AIR AGENCIES, COMMENTS ON DOCKET ID NO. EPA–HQ–OAR–2009–0234 (Aug. 4, 2011) (discussing experiences in regulated states).

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[27] U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-10-47, MERCURY CONTROL TECHNOLOGIES AT COAL-FIRED POWER PLANTS HAVE ACHIEVED SUBSTANTIAL EMISSIONS REDUCTION 8 (2009) (finding that sorbent injection can be used to reduce mercury emissions on boiler configurations present at nearly three-fourths of coal-fired EGUs).

B. Between 2000 And 2012, Many EGUs Installed Control Technologies That Will Reduce Mercury And Other HAP Emissions In Response To Federal Regulation Of Other Pollutants And Were Able To Meet The MATS Requirements Before They Took Effect.

MATS was not the only federal regulatory initiative that affected mercury and HAP emissions from EGUs. CAIR required the EGUs in 28 states to limit their own emissions of NO_x and SO_2 if those emissions would contribute to nonattainment of NAAQS in another state. The NO_x SIP call required 26 states, mostly in the eastern U.S., to submit state implementation plans that would address the interstate transport of NO_x and the formation of ozone. The Acid Rain Program, part of the 1990 CAA amendments, had also created incentives for EGUs to control SO_2, although not to the extent hoped for at its enactment.[28] While none of these rules addressed mercury or HAP emissions *per se,* EGUs installed a variety of control technologies – including scrubbers and other FGD technologies – in order to comply with their requirements.

As a result of the limitations on SO_2 and NO_x, between 2000 and 2011, EGUs representing 80 GW

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[28] The Title IV Acid Rain Program (CAA §§ 401-416) differed from other EPA regulations because it allowed for SO_2 emissions trading, allowing some EGUs to lower their emissions and obtain allowances or credits which they could then sell to EGUs that did not lower their emissions to the same degree.

of generating capacity (approximately 25 percent of the U.S. total) installed FGD technology, and EGUs representing 96 GW of generating capacity (approximately 30 percent of the U.S. total) installed SCR systems. 2011 NESCAUM Report at 26. These control technologies had the practical co-benefit of limiting mercury and other HAPs, in addition to their primary duties of reducing criteria pollutants.

EGU operators have come to recognize that mercury and other HAP emission control is technologically, operationally, and financially feasible. Perhaps the most telling statistic is this: "At the end of 2012, 64.3 percent of the U.S. coal generating capacity in the electric power sector already had the appropriate environmental control equipment to comply with the MATS" – more than two years before MATS was scheduled to take effect. U.S. ENERGY INFO. ADMIN., *Coal-fired power plant operators consider emissions compliance strategies* (Mar. 28, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=15611. Factoring in the additional capacity that already planned to add control equipment before the compliance deadline, nearly 70 percent of total coal-fired capacity was either in compliance with the MATS or already had plans in place to achieve compliance at the end of 2012. Only a minority still needed to determine how to comply with MATS – and it had over two years to do so. *Id.* This is on-the-ground confirmation that regulation of HAP emissions at EGUs was appropriate and that EPA's decision was and remains reasonable.

CONCLUSION

For the foregoing reasons, this Court should affirm the lower court's decision.

Respectfully submitted,

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